

Identifying and Evaluating Opportunities for Greenhouse Gas Mitigation & Operational Efficiency Improvement at Oil and Gas Facilities



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DISCLAIMER

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Special thanks are given to members of the GMI Oil & Gas Subcommittee for their guidance and constructive review comments. The update of this document was part of the GMI Oil & Gas Subcommittee 2018 Action Plan to advance project implementation, facilitate investment, and create appropriate policy frameworks that support methane abatement, recovery, and use.

The GMI Oil & Gas Subcommittee focuses on supporting identification and deployment of practical and cost-effective methane mitigation technologies and practices to reduce or eliminate emissions from oil and natural gas systems. This is achieved by encouraging collaboration among Partner Countries, subcommittee members, and Project Network members to build capacity, develop strategies and markets, and remove technical and nontechnical barriers to methane mitigation project development. Ultimately, such collaboration will improve environmental quality and operational efficiency, and strengthen the economy by bringing additional methane to market.

EXECUTIVE SUMMARY

This document presents introductory guidance on a pragmatic integrated approach to identify, evaluate, and advance cost-effective, high-impact opportunities to further manage greenhouse gas (GHG) emissions and energy use at oil and natural gas facilities. The focus is primarily on key sources of short-lived climate pollutants (SLCP) and less on effective energy management strategies. The primary audience for this document includes company management, facility operators, and relevant service providers outside of North America (particularly, where other regulatory guidance to GHG reductions and energy management may not be available). The primary aim of this guide is to help identify opportunities for cost-effective mitigation of methane and more energy-efficient operations, with focus on types of facilities and operations mostly likely to offer such opportunities based on practical experience. The guide identifies specific operational issues or problems that could contribute to unaccounted emissions, product losses, and process inefficiencies.

This document references relevant standards, guidelines, and best management practices from North America to provide the reader access to detailed information on measurement or assessment techniques and available control technologies. This includes references to relevant documents published by EPA's Natural Gas Star Program (<https://www.epa.gov/natural-gas-star-program/recommended-technologies-reduce-methane-emissions>) and the Climate and Clean Air Coalition (CCAC) Oil and Gas Methane Partnership (OGMP) (<http://ccacoalition.org/en/content/oil-and-gas-methane-partnership-technical-guidance-documents>).

This guide also provides information on developing and financing a GHG mitigation project, including a discussion of the project development cycle and enabling conditions for successfully advancing GHG emission reduction projects, namely:

- Developing a credible business case.
- Identifying and quantifying potential risks.
- Highlighting co-benefits (especially those that align with company and local or regional priorities).

Information presented on potential funding mechanisms includes a discussion of the following options:

- Self-financing.
- External debt and equity financing.
- Partnerships.
- Third-party agreements.

A key consideration at oil production facilities (based on current commodity pricing) is that most economic value of any waste-associated gas streams rich in non-methane hydrocarbons tends to come from the liquefied petroleum gas (LPG) and natural gas liquids (NGL) fractions rather than the methane. The LPG and NGL value is realized only if the gas is processed on site or at a

downstream gas processing plant. Feasible economic opportunities exist to recover the LPG and NGL (even at a small scale) to power the process and flare the balance if it cannot be used. Operators can recombine the recovered liquids with the weathered crude oil and send it to market via the existing crude oil transportation system if the Reid vapour pressure¹ (RVP) of the blended product is properly managed to comply with the shipper's specifications.

¹ Reid vapour pressure (RVP) is the vapour pressure of crude or petroleum-refined products measured at 37.8 degrees Celsius (°C) (100 degrees Fahrenheit [°F]) and a vapour-to-liquid ratio of 4:1. The applicable test method is ASTM International (ASTM) D323. The RVP may be applied to estimate the true vapour pressure at other temperatures by use of the American Petroleum Institute (API) correlation published in the *API Manual of Petroleum Measurement Standards* (MPMS) Chapter 19.2 (formerly API 2517). Crude oil purchasers and transporters often specify maximum allowable RVPs to minimize product losses due to weathering effects. Typical RVP requirements for crude oil sales range from 70 to 82 kilopascals (kPa) (10 to 12 pounds per square inch [psi]).

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LIST OF ACRONYMS

°C	Degrees Celsius
°F	Degrees Fahrenheit
API	American Petroleum Institute
ASTM	ASTM International
AVO	Audible, visual, or olfactory
AWP	Alternative work practice
BMP	Best Management Practice
BLT	Build-lease-transfer
BOO	Build-own-operate
BOOT	Build-own-operate-transfer
BOT	Build-operate-transfer
BTEX	Benzene, toluene, ethylbenzene, and xylenes
CAPEX	Capital expenditure
CAPP	Canadian Association of Petroleum Producers
CARB	California Air Resources Board
CCAC	Climate and Clean Air Coalition
CEPEI	Canadian Energy Partnership for Environmental Innovation
CETAC	Canadian Environmental Technology Advancement Corporation
CH ₄	Methane
CO	Carbon monoxide
CO ₂	Carbon dioxide
CO _{2e}	Carbon dioxide-equivalent
m ³ /d	Cubic Meters Per Day
DBM	Design Basis Memorandum
DBOT	Design-build-operate-transfer
EMM	Emissions Mitigation Mechanism
EPA	U.S. Environmental Protection Agency
ETS	Emission Trading System
EU	European Union
FEED	Front-end engineering design
GBP	Green Bond Principles
GGFR	Global Gas Flaring Reduction Partnership
GHG	Greenhouse gas
GMI	Global Methane Initiative
H ₂ S	Hydrogen sulfide
ICMA	International Capital Market Association
IETA	International Emissions Trading Association

ITMO	Internationally transferred mitigation outcome
kg/h	Kilograms per hour
kPa	Kilopascal
LDAR	Leak detection and repair
LHV	Lower heating value
LP	Limited Partnership
LPG	Liquefied petroleum gas
MJ/kmole	Megajoules per kilomole
Mm ³ /d	Million cubic meters per day
MPMS	Manual of Petroleum Measurement Standards
MRV	Measurement, reporting, and verification
Mt/y	Million tons per year
NDC	Nationally Determined Contributions
NGL	Natural gas liquid
NO _x	Nitrogen oxides
OEE	Office of Energy Efficiency
OGI	Optical gas imaging
OGMP	Oil and Gas Methane Partnership
P&ID	Piping and instrumentation drawing
PERD	Program for Energy Research and Development
psi	Pounds per square inch
PTAC	Petroleum Technology Alliance of Canada
PM	Particulate matter
QA	Quality assurance
QC	Quality control
RVP	Reid vapour pressure
SBG	Sustainability Bond Guidelines
SBP	Social Bond Principles
SLCP	Short-lived climate pollutant
SO ₂	Sulfur dioxide
TEAM	Technology Early Action Measures
UPAIRI	Upstream Petroleum Air Issues Research Initiative
USD	United States dollars
VAT	Value added tax
VCCS	Vapour collection and control systems
VOC	Volatile organic compound

1 Introduction

This document presents a practicable approach to identify and develop cost-effective, high-impact opportunities to reduce GHG emissions (especially short-lived climate pollutants [SLCP] such as methane [CH₄] and black carbon), and to improve energy efficiencies at oil and natural gas facilities. The focus is primarily on key sources of SLCPs and less on effective energy management strategies.

This document uses the term “emissions mitigation review” throughout to describe application of this approach at oil and gas facilities. Overall objectives are to maximize effectiveness of GHG emission reduction efforts and provide consistency in results needed to generate, and subsequently sustain, industry and investor support while addressing local barriers and circumstances.

This document begins with guidance on systematically identifying and evaluating emission reduction opportunities at oil and gas facilities by conducting prefeasibility assessments and ultimately developing refined business cases for consideration by senior management and potential investors to implement these opportunities. Explanations are provided on why emission reduction opportunities exist, advantages of conducting an independent evaluation, and potential uncertainties. Guidance is also provided on how to access financing needed to implement projects.

Since development of the initial document in 2008, there has been a significant improvement in technical knowledge regarding key types of sources to target and control strategies for these sources, the understanding of enabling conditions for successfully advancing projects, and the availability of more potential funding mechanisms to implement projects. This updated version includes new information that renders the document more relevant within the current business environment. A broader framework is provided on how to justify and facilitate implementation of CH₄ and other emission mitigation projects in the context of the industry’s key performance indicators and competing investment opportunities for available funds. The important potential co-benefits of GHG mitigation actions are highlighted, including:

- Improved operational efficiencies.
- Increased revenues.
- Reduced emissions of other co-pollutants that are hazardous to human health.
- Enhanced workplace safety.
- Conservation of a non-renewable resource.
- Improved system reliability.
- Alignment with corporate policies regarding sustainable development and social license.
- Potential access to green funding mechanisms.

Highlighting such co-benefits increases the likelihood of companies approving investments in CH₄ and other GHG mitigation measures. To maximize benefits achievable at each site, a holistic approach to identify key cost-effective opportunities for reducing CH₄ and other GHGs emissions, volatile organic compounds (VOC), and black carbon should be considered. This

would allow conveyance of co-benefits of CH₄ projects in a manner that may better align with site-specific and jurisdictional priority objectives, and thereby strengthen the case for investing in identified mitigation opportunities.

1.1 Why Conduct GHG Mitigation Reviews?

With rising energy demand and increasing emphasis on sustainable development, the need to reduce fugitive emissions, avoidable wastage, and inefficiencies is becoming increasingly more important. Experiences in many countries have revealed significant cost-effective opportunities to reduce GHG emissions and improve energy efficiencies at oil and natural gas facilities. Financial payback periods of such opportunities are frequently less than two years and often less than six months. Targeting such opportunities makes good financial sense and offers the following potential co-benefits: increased output, reduced operating costs, resource conservation, improved local air quality (for example, through reduced emissions of hydrogen sulfide [H₂S], VOCs, nitrogen oxides [NO_x], sulfur dioxide [SO₂], carbon monoxide [CO] and particulate matter [PM]), local job creation, a safer workplace, improved system reliability, and best-in-class recognition.

Much effort has been exerted to take advantage of cost-effective opportunities at facilities; however, many countries and companies still struggle with decisions on where and how best to allocate resources for reducing GHG emissions. Often companies arbitrarily pick control technologies and apply these without first seeking out optimum applications for the technologies, which can produce mixed results.

This guide highlights a best practice approach to first find a facility or site-specific, cost-effective control opportunities, and then determine the most practicable control option for each of these opportunities based on site-specific constraints and circumstances. Experiences in North America² have demonstrated that a systematic and holistic approach to first evaluate and benchmark facilities identifies optimum emission reduction opportunities and produces the most consistent value-based results. Moreover, a well-structured and transparent approach to find and evaluate the best control opportunities also provides the information ultimately needed to generate verifiable carbon credits. The first goal is to find and sufficiently delineate these opportunities to make the necessary project business case required to secure management approval and authority for expenditures.

Efforts to identify significant cost-effective emission reduction opportunities at North American upstream oil and gas facilities have revealed that many types of opportunities have a skewed distribution where a few facilities are performing very poorly (with respect to a specific emission or efficiency matter) and other facilities are performing very well. Most facilities have at least some meaningful opportunities for improvements in GHG emissions and energy management given the broad range of potential opportunities.

² This is primarily through federally funded research studies conducted in Canada by the Canadian Environmental Technology Advancement Corporation (CETAC-West) and the Petroleum Technology Alliance of Canada (PTAC), with the financial support of programs such as the PERD, Technology Early Action Measures (TEAM), and the Office of Energy Efficiency (OEE), and similar work in the United States by EPA.

Applying holistic survey methods aimed at high-potential segments of the industry has proven successful in generating consistent environmental benefits with cost-effective implementable solutions. This approach takes maximum advantage of the mitigation review team's expertise and measurement equipment while they are on site and increases the potential number of identified cost-effective emissions reduction opportunities. A rational and systematic approach to finding practicable high-impact GHG emission reduction opportunities benefits the environment and is profitable for industry.

1.2 Why Do Significant Cost-Effective Mitigation Opportunities Exist?

There are two main reasons why a significant cost-effective opportunity for GHG emissions or energy management improvement may persist at a facility: 1) the opportunity does not produce a readily noticeable effect (for example, the opportunity may develop gradually over time or is obscured by other factors) or 2) the magnitude of the opportunity is not easy to determine for the purpose of informing or justifying appropriate mitigative action.

Mitigation opportunities develop in the first place for the following reasons:

- Progressive deterioration of facilities.
- Changes in operating conditions from initial design values.
- Use of outdated technologies, designs, or operating practices.
- Budget constraints during initial implementation of an energy development project, resulting in design bottlenecks, deficiencies, and compromises that contribute to excessive fuel use, increased venting and flaring, and fugitive emissions.
- Lack of instrumentation, process controls, monitoring systems, and performance benchmarking to detect and quantify avoidable losses and inefficiencies.
- Internal policies and key performance indicators that create disincentives for optimizing operational performance.

1.3 What are the Key Advantages of Integrated Mitigation Reviews?

While self-reviews may be done by facilities, it is usually preferable to use a dedicated team, even if it is internal to the company, that is equipped with the necessary tools and resources to do conduct the review. This document encourages companies to develop such teams, and these teams will use this document to identify mitigation opportunities. The main advantages of having a dedicated team include:

- Convenient access to specialized measurement and testing technologies needed to perform the work.
- Fresh views and insights coupled with expert knowledge and capabilities of the review team.
- Increased probability of identifying significant, cost-effective, CH₄ emission reduction opportunities through a comprehensive multi-disciplinary facility examination.
- Avoidance of exceeding available on-site resources.

- Potential synergies between disciplines for improved identification of opportunity.
- Maximum utilization of the review team’s expertise.
- Independent verification of the facility’s performance.
- Transparent third-party determination of the emissions baseline and other data needed for development of a credible business case suitable for senior management and investor or financier approval.
- Opportunity for technology transfer and training of facility staff.

Additionally, the review provides the means to monitor performance over the long term by comparing system performance to the baseline established at the time of the initial facility surveys. This benchmarking is applicable at the facility level and at the individual process unit level.

1.4 What is the Opportunity Potential?

While results achieved may vary dramatically among individual facilities, GHG emission mitigation reviews conducted at facilities internationally and in North America indicate that average improvements, as indicated in Table 1, are reasonable.

Table 1: Typical average improvements from implementing cost-effective emission reduction and energy-efficiency improvement opportunities

Parameter	Percentage Reduction
Fuel Gas Consumption	13%
Electricity Demands	9%
Fugitive Equipment Leaks	70%

Source: General findings of a series of measurement and energy management programs sponsored by CETAC West during the early 2000s.

Older facilities, especially those with inadequately funded maintenance programs, are most likely to have the greatest opportunities. Other contributing factors include the following:

- Effectiveness of the operator’s technology and design standards, management systems, and organizational culture.
- Effectiveness of local regulatory enforcement efforts.
- Reduced use of process instrumentation and continuous monitoring systems, rendering identification and evaluation of opportunities more difficult.
- Rules, regulations, management systems, and fiscal policies that may be disincentives to emissions and energy management.
- Limited access to, and increased costs of, best technologies and practices.
- Potential quality control (QC) issues with locally produced products and technologies.

1.5 What are the Key Factors Affecting Viability of Mitigation Opportunities?

Key factors affecting potential for viable GHG mitigation opportunities include the following:

- Costs of financing.
- Capital and operating costs of the mitigation option.
- Duties.
- Tax and royalty regimes, and the extent of any concessions.
- Market accessibility and pricing for any produced products.
- Potential to conserve or utilize recovered natural gas.
- Existence of emission fees and carbon market.
- Production decline rates and remaining life expectancy of the facility.
- Potential to redeploy mitigation technology at other facilities at the end of the current facility's life.

1.6 Why Don't Good Mitigation Projects Always Get Advanced?

To advance within any organization, a project must satisfy the following criteria:

- The project must be clearly defined and properly documented (for example, a credible business case with sufficient detail and accuracy to allow informed decisions by senior management and potential investors or financiers to invest in the project).
- Risks to costs and time to complete the project are known and acceptable.
- The economics meet or exceed investment hurdle rates expected for the level of risk.
- The project must align with the operator's priority objectives, core competencies, business strategy, and available financial resources.
- The project must align with market key performance indicators (for example, increased reserves, production, revenues, and profits).
- The project must be competitive with other potential investment opportunities.
- The project must be sufficiently large to justify costs of due diligence.

Regulatory compliance can override these criteria, especially if failure to achieve compliance would pose risk to continued operation of the facility.

Existence of material secondary benefits or rewards can improve the attractiveness of the project, but generally are not sufficient for a project to receive approval. These benefits may include strengthened social license, compliance with future legislation, improved workplace safety, sustainable development, improved system reliability, best-in-class recognition, and potential carbon credits or avoidance of emission fees.

1.7 What Are the Uncertainties?

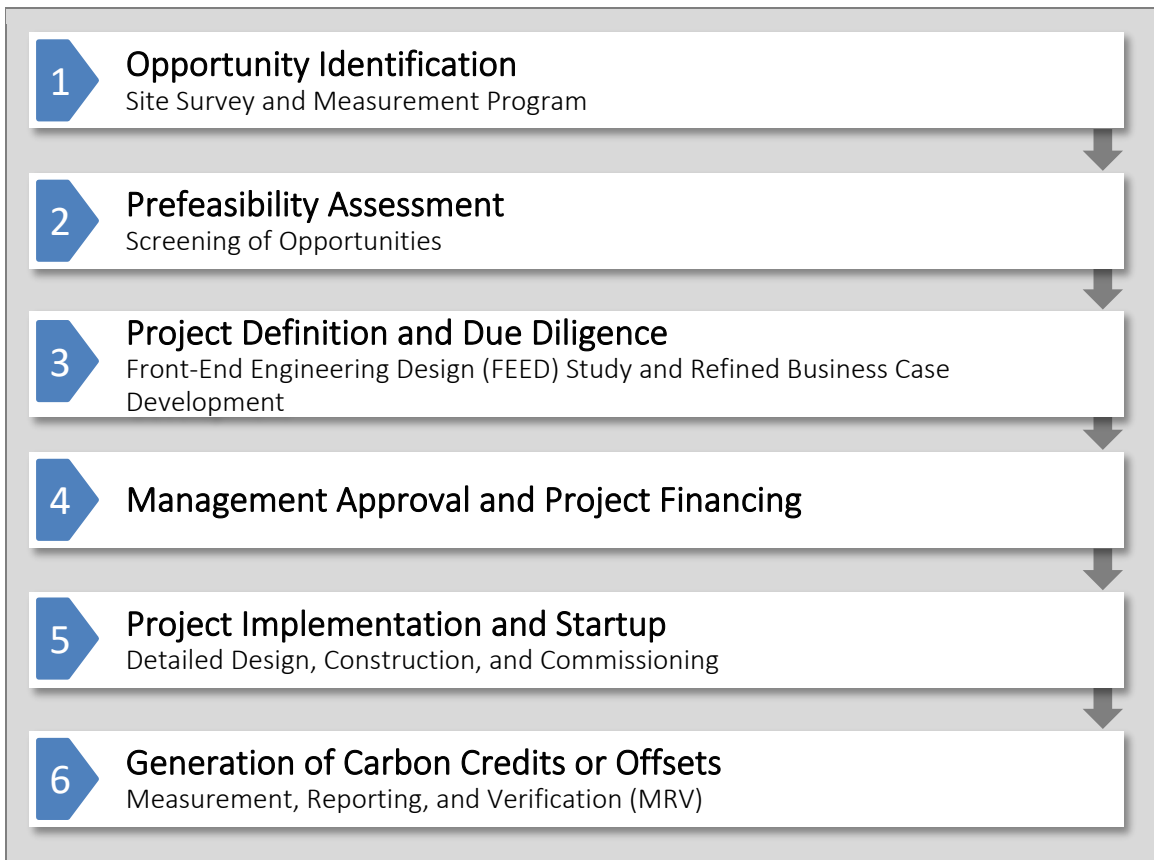
Key uncertainties are potential differences in opportunity economics and frequency distributions. Factors that contribute to these uncertainties include the following:

- Differences in design standards and operating practices.
- Differences in extent of market access.
- Remoteness of facilities.
- Potential security issues.
- Age of the facilities coupled with declines in rate of production and operational efficiency.
- Reduced use of process instrumentation and continuous monitoring systems, rendering identification and evaluation of opportunities more difficult.
- Rules, regulations, management systems, and fiscal policies that may be disincentives to emissions reduction.
- Low labour costs and corresponding emphasis on manual versus instrumental or automated solutions.
- Limited access to, and increased costs of, foreign technologies.
- Limited access to the skilled labour or training needed to operate and maintain advanced technologies.
- Potential QC issues with locally produced products and technologies.
- Protectionist laws and duties aimed at excluding foreign goods and services.

2 Development of GHG Mitigation Projects

Conducting a GHG emissions mitigation review at a facility is only the first in a series of steps needed to develop and implement strategic, high-impact, GHG mitigation projects, and potentially generate marketable carbon credits or offsets. Figure 1 depicts the general flow for a project in which the mitigation measure requires a capital solution, although actual requirements may vary by company and the magnitude of the project. Ultimately, for a project to proceed it must be quantifiable, viable, and align with the company’s priority objectives. Projects for which only a simple maintenance or operational solution is needed may usually be addressed through normal facility operating budgets and avoid the more onerous and time-consuming requirements of capital projects.

Figure 1: General Project Flow Diagram



The typical primary stages of developing a capital GHG mitigation project may be classified as indicated below and are discussed in more detail in subsequent corresponding subsections:

1. Opportunity Identification.
2. Prefeasibility Assessment.
3. Project Definition and Due Diligence.
4. Management Approval and Project Financing.
5. Project Implementation and Start-up.
6. Generation of Carbon Credits and Off-sets.

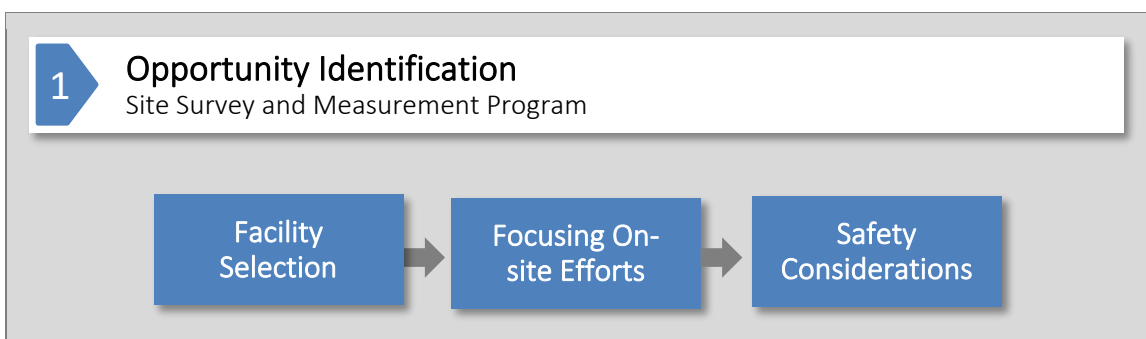
Actual requirements will vary by company.

2.1 Opportunity Identification

A facility may know of or suspect some mitigation opportunities but are not addressed because data to quantify their economic impact and inform any mitigative response are unavailable, and the matter is not perceived to pose a process or safety concern. Other opportunities may occur and persist but the facility may not be aware of them due to lack of relevant monitoring systems, inability to trigger process indicators, or absence of audible, visual, or olfactory (AVO) indicators.

The integrated emissions mitigation review serves two key purposes. First, the review is a useful tool for seeking out and delineating potential opportunities for cost-effective GHG emissions mitigation in a manner that maximizes potential benefit achieved. Second, the review provides an assessment of baseline emissions and the quantitative, source-specific information needed for a preliminary screening-level engineering, operational, and feasibility assessment of these opportunities. Key elements of the opportunity identification stage are depicted on Figure 2 and discussed in the following subsections.

Figure 2: Key Elements of the Opportunity Identification Stage



2.1.1 Facility Selection

Significant cost-effective emission mitigation opportunities can occur and have occurred in almost all conceivable situations; however, these are more likely to occur in certain predictable situations. The best place to begin is with facilities that have compression or significant process

heat demands, are more than 20 years old (typical maximum design life of a facility), and either having gone through multiple ownership changes or undergoing significant decline in production.

Older facilities were often designed when energy prices were low and energy efficiency was less of a concern; therefore, these facilities may offer good opportunities for efficiency improvement. Facilities designed during periods of fiscal restraint are likely to present opportunities for significant efficiency improvement and waste gas recovery.

Facilities that have undergone multiple ownership changes are usually either marginally economic or are approaching the end of their lives. Many facilities that are 40 to 60 years old and still operating today originally were designed to operate for only 20 years or less. As energy prices increase and drilling and production technologies improve, lives of facilities are frequently extended well beyond initial expectations. Reviews of facilities known to be within a few years of closure may be worthwhile, given the short payback periods for some opportunities, especially where saleable carbon credits can be produced.

Other indicators to identify when selecting a facility include the following:

- Poor housekeeping – usually an indicator of poor morale, which may contribute to neglect and deteriorated equipment performance.
- Significant venting and flaring at older facilities – the economics of waste gas recovery or utilization may have improved dramatically from the time the facility was first commissioned.
- Significant flaring and venting at gas production, processing, and transmissions facilities – these facilities already have access to the infrastructure necessary to conserve the gas, so the economics of managing such losses can be very attractive.
- Significant flaring or venting at petroleum refineries and petrochemical plants – these facilities purchase all their energy and feedstock, so addressing the root cause of a flaring or venting can be very economically attractive as well.
- Oil production facilities with access to gas gathering or utilization systems but do not feature any vapour recovery on their storage tanks – once a solution is in place to conserve or utilize the associated gas production at an oil production facility, implementation of vapour recovery often will be practicable.

2.1.2 Focusing On-site Efforts

It is not practicable to expect that the review team would conduct an exhaustive effort to identify and evaluate all potential opportunities at each target facility. There is ultimately a point of diminishing returns, both in terms of size and diversity of the review team assigned to the task and the scope of work to be performed. Sections 3 to 8 of this document highlight a range of opportunities worth considering.

The aim should be to acquire in advance as much useful information about the facility as possible to help plan and focus the review team's field efforts. Additionally, once the review team is at the site, and before initiation of the field review, senior facility personnel should meet

to discuss the facility's operations and areas of potential concern. Often, facility personnel will be aware of good opportunities but will lack the quantitative data needed to present a defensible business case to management. It is important to take advantage of this information but not let it bias the review (that is, cause the team to overlook other opportunities). The team needs to adapt to actual circumstances at the time and use professional judgement. For this reason, the review team must include senior personnel able to apply sound judgement in the field.

Time and effort spent on each item should be commensurate with the magnitude of the opportunity. For example, as soon as there is a reasonable quantitative or qualitative indication that an opportunity will be small, the team should document the basis for this conclusion and move on to the next item. If the team identifies a large opportunity, then it may be appropriate to conduct replicate measurements and document the variability of the opportunity.

Data collection sheets and checklists should be used throughout the review to help guide the process and avoid missing critical information.

Information that the team should request prior to the site visit includes the following:

- Site plot plan.
- Production accounting summary, including flow rates of all input and output streams and a fuel gas disposition analysis.
- Summaries of purchased propane, fuel, and electricity.
- Copies of recent stream analyses for use in performing mass balances.
- Lists of all engines and process heaters, and, if readily available, information on their make, model, age, rated capacity, and emission controls.
- Process flow diagrams showing all points where flow rates are metered.
- Screenshots from the process data acquisition system and process log sheets showing all monitored temperatures, pressures, and flows throughout the facility.

The team can use the information to conduct preliminary mass balances and energy balances to help identify areas where excessive losses or low efficiencies are occurring. The information also familiarizes the review team with the facility design and layout, and allows identification of priority review targets and needs.

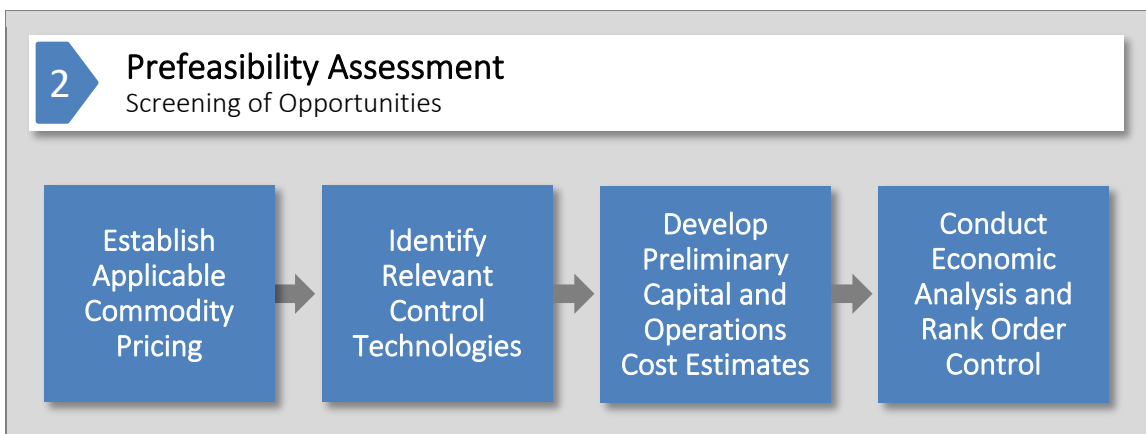
2.1.3 Safety Considerations

Emission measurements and process tests should occur where safe to do so. The review team should be responsible for providing their own basic personal protective equipment. The host facility should be responsible for providing any special provisions (such as ladders, man lifts, lanyards, safety watches, and supplied breathing air) needed to safely access individual components and vent outlets (for example, compressor-seal vent outlets).

2.2 Prefeasibility Assessment

A prefeasibility assessment provides an approximate quantitative indication of the economic viability of an identified opportunity and is a tool for a preliminary screening of opportunities; it includes the basic activities depicted on Figure 3. To advance beyond the prefeasibility assessment, the opportunity will have to show potential for both favorable economics and a high impact. If the opportunity is too small, the operator may find the necessary due diligence too costly relative to benefits. It may be necessary to combine multiple smaller opportunities of the same or related type to achieve sufficient benefit. Conversely, if a project is too large, obtaining the necessary financing may be a challenge. A project is normally considered small when it has a capital expenditure (CAPEX) of less than \$1 million and large when the value exceeds about \$10 million.

Figure 3: Key Elements of the Prefeasibility Assessment Stage



Typically, gross revenue or avoided operating costs achievable by a mitigation measure are estimated based on current commodity prices and data from limited spot (or point-in-time) measurements performed during the review. A key consideration at oil production facilities (based on current commodity pricing) is that most economic value of any waste-associated gas streams rich in non-methane hydrocarbons tends to come from the LPG and NGL fractions rather than the methane. The LPG and NGL value is realized only if the gas is processed on site or at a downstream gas processing plant. Attractive economic opportunities exist to recover the LPG and NGL (even at a small scale) and use the methane just to power the process, with the balance flared if it cannot be conserved. The recovered liquids can be recombined with weathered crude oil and sent to market via the existing crude oil transportation system, provided that vapour pressure (or volatility) of the blended product is properly managed to comply with buyer and shipper specifications.

Capital costs used in a prefeasibility assessment are determined using either Class 5 (capacity factored) or Class 4 (equipment factored) cost estimating techniques published by international standard developing organizations ASTM International (ASTM) and AACE International (see Table 2 below). Results are corrected to present-day values and tend to be order-of-magnitude cost estimates. A Class 5 estimate is derived from available costs of a similar facility or system

using a parametric model, judgement, or analogy. A Class 4 estimate is derived from similar cost estimates of major equipment and use of equipment installation factors.

Operating costs may be estimated using the method published by Chemical Engineering Projects (<https://chemicalprojects.wordpress.com/2014/05/11/estimation-of-operating-costs/>). Energy and other utilities needs are often the dominant operating costs.

Site-specific constraints and considerations that could materially affect viability of the project are poorly known at this point. These could include, but are not limited to, the following:

- Ability of the existing utility, process and control systems (where applicable) to meet project needs, and cost implications of satisfying any incremental demands.
- Type of control system required.
- Locations and details of existing process and utility tie-in points.
- Amount of piping, electrical, and instrumentation work needed to integrate the mitigation measure with the existing process.
- Availability and reliability of current drawings showing structures, underground services, fire protection systems, roads, and pipeline corridors.
- Critical environmental and other regulatory requirements.
- Availability of sufficient spacing for the new infrastructure or ability to satisfy incremental needs at a reasonable cost.
- Access to transportation systems and nearby markets for any new products.
- Remaining life of the existing operation.
- Increased manpower requirements and need for specialized disciplines that cannot be fully utilized.
- Geotechnical considerations.
- Amount of any opposition from nearby residents.
- Disincentives, such as contractual agreements, administrative structure, and corporate policies that prevent those responsible for the costs of implementation from sharing in the benefits achieved.
- Lack of practicable, on-site opportunities to utilize waste energy.
- Need for any costly safeguarding and monitoring measures.
- Excessive variability or intermittent nature of the source.
- Uncertainties regarding representativeness of compiled source data.

In developing countries and countries with economies in transition, additional considerations may include:

- Lack of access to information, contractors, experience, and necessary financial resources necessary to complete the front-end engineering assessment.
- Cultural, language, and calendar differences that require more planning and longer response times.

- Differences and difficulties in the local political context in which the companies are operating.
- Slowness of local companies to embrace an international program, for reasons ranging from corporate policy independence to reticence regarding commitments.

Assuming the above matters can be addressed, the project still has to compete against other potential investment opportunities. Not only must the project be competitive from a financial perspective, but it must also overcome the traditional focus on increasing shareholder value through exploration and development, rather than reducing wastage or losses and improving efficiency.

Table 2: Summary of cost estimation classifications published by AACE International

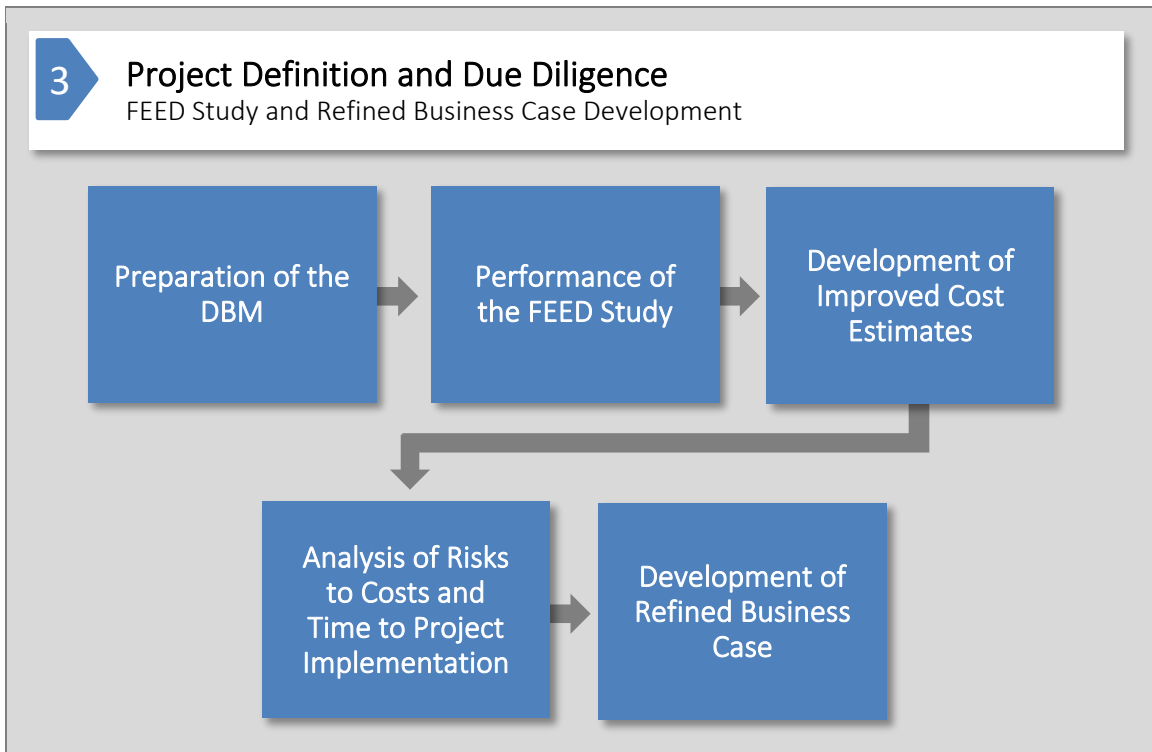
Estimate Class	Name	Purpose	Expected Uncertainty Range	Maturity Level of Project Definition
Class 5	Order of Magnitude	Screening or feasibility	L: -20% to -50%	0% to 2%
			H: +30% to +100%	
Class 4	Intermediate	Conceptual study or feasibility	L: -15% to -30%	1% to 15%
			H: +20% to +50%	
Class 3	Preliminary	Budget authorization	L: -10% to -20%	10% to 40%
			H: +10% to +30%	
Class 2	Substantive	Control or bid/tender	L: -5% to -15%	30% to 40%
			H: +5% to +20%	
Class 1	Definitive	Check estimate or bid/tender	L: -3% to -10%	50% to 100%
			H: +3% to +15%	

2.3 Project Definition and Due Diligence

If the opportunity passes the prefeasibility or screening-level assessment, the next step is to better define the project to more accurately assess its feasibility and risks, as depicted on Figure 4. This requires preparing the following items:

- Design Basis Memorandum (DBM).
- Front-end Engineering Design (FEED).
- Refined Business Case.

Many opportunities that look promising at the prefeasibility stage may be determined impractical or infeasible as the project becomes more defined, or may just be rejected because they do not align well with the operator’s business model or are perceived to pose unacceptable risks.

Figure 4: Key Elements of the Project Definition and Due Diligence Stage

2.3.1 Design Basis Memorandum

One of the first tasks that should be completed during the project definition phase is the preparation of the DBM (or project design criteria). The DBM establishes the basic design parameters needed for preliminary engineering work to proceed. The DBM typically includes a description of the project and its objectives, performance specifications of the considered mitigation measure(s), input design data (for example, compositions, flows, temperatures, and pressures), and standards and regulations to which the mitigation solution is to be designed. Supplemental measurement work may be necessary to reaffirm and complement audit results (for example, 24-h tests, and replicate or more current sampling and analysis of the process fluids), and to better inform the engineering work. Additionally, the operator may have to review and mine the facility's existing drawings and equipment data books for relevant information. The DBM tends to be a living document that is revised throughout the engineering process as new information becomes available and the design is refined.

2.3.2 Front-end Engineering Design

The FEED is the engineering work needed to narrow the relevant mitigation options to a single choice or concept, and to determine the main technical requirements associated with the final concept. Key FEED activities may include preparing or obtaining the following:

- An updated site-plot plan showing where all proposed infrastructure and equipment would be placed relative to existing infrastructure at the site.

- Piping and instrumentation drawings (P&ID) showing details of the solution and how it will be integrated with the existing process.
- Datasheets detailing sizing and specifications of all major pieces of equipment, controls, and instrumentation to be installed.
- Size and routing plans for any required pipeline segments.
- Regulatory approvals (if the risk of obtaining approvals is low, this may be deferred until after project approval is obtained).
- Class 3 cost estimates (see Table 2). This is a budgetary cost estimate used for final investment decisions and is derived from semi-detailed unit costs with bulk material take-offs.

2.3.3 Refined Business Case

The refined business case is necessary to support decisions by the operator's senior management and potential investors or financiers. This involves preparation of more accurate costs (typically Class 3) based on the improved project definition provided by the FEED study, update of the feasibility assessment and detailing of any risks to costs, timely project implementation, and reliable ongoing operation of the mitigation measure. Feasibility results are benchmarked against the acceptance criteria of the operator, investor, and/or financier. Details are provided to show how the project aligns with the operator's priority objectives and business model.

2.4 Management Approval and Project Financing

Significant time and effort may be necessary to refine the project and advance it to the stage in which senior management and potential investors/financiers can make an informed decision on the matter. It is not sufficient that the project be profitable or provide material co-benefits. The project must also be competitive against the operator's other investment opportunities, pose an acceptable level of risk, align with the operator's key performance indicators, and be understandable and valuable to shareholders, investors, and financiers.

If the project involves a mitigation measure familiar to and commonly implemented by the operator, its development and approval cycle will be much shorter and less onerous. Projects new to the operator or that do not align well with the business model will be much less likely to succeed.

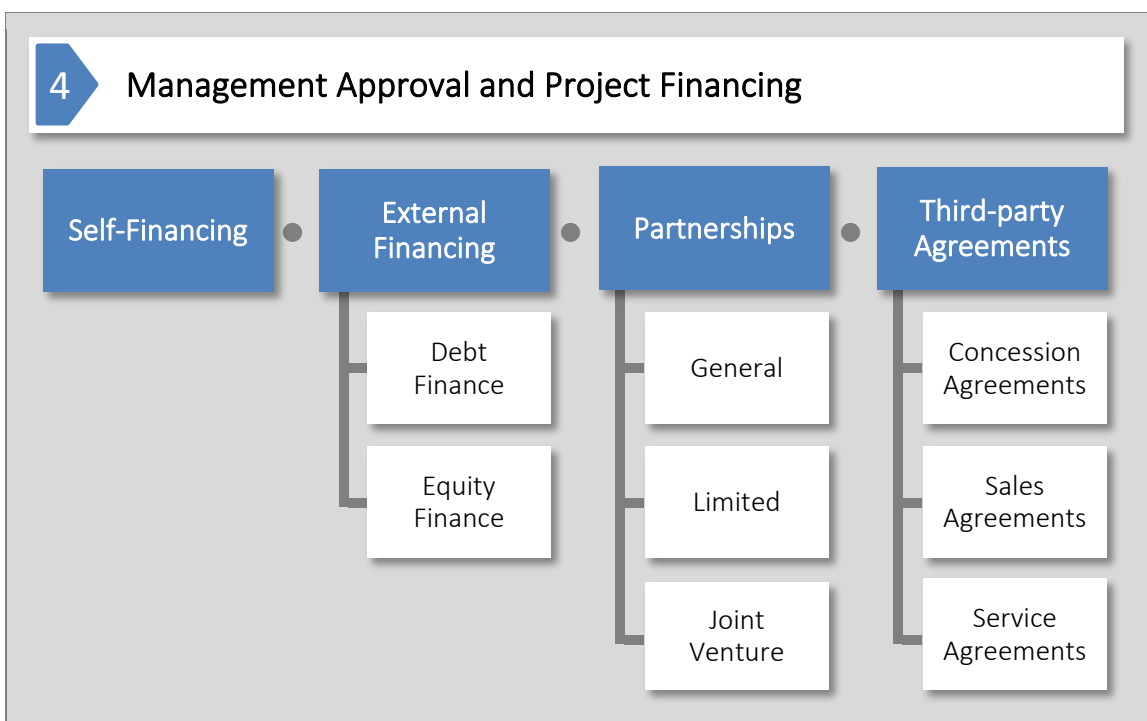
To sell the project to management, the operator should show competitive financials and alignment with the company’s priority objectives and business model and highlight any quantifiable co-benefits, which may include:

- Improved workplace air quality resulting in worker health and safety benefits.
- Improved local air quality resulting in human health and environmental benefits, as well as improved public relations.
- Reduced wastage, inefficiencies, and system losses resulting in improved profitability (that is, through conservation of a non-renewable resource, increased product yields, improved system reliability, increased sales, and reduced energy consumption).

Financing mechanisms for cost-effective GHG mitigation projects include the following and are depicted on Figure 5:

- Self-financing (from internal cash flows).
- External financing.
- Partnerships.
- Third-party agreements.

Figure 5: Potential Project Financing Mechanisms



2.4.1 Self-Financing

If a company is profitable, it may consider financing GHG mitigation projects out of its revenues. This avoids interest payments and need to repay any capital, but may be practical only for small to medium sized projects.

In the same way that some companies devote a certain percentage of their revenues to research and development efforts, some companies have given thought to either allocating a certain percentage of their revenues to green projects or establishing an internal green fund that would be used to finance its green projects. The intent in the latter case would be for the fund to share in a portion of the revenues generated by the green projects with its sponsors so that the fund can grow and continue to support such projects.

2.4.2 External Financing

There are two main types of external finance: debt and equity. A comparison of debt and equity is provided in Table 3. Debt finance is money borrowed from external lenders, such as a bank, which must be paid back with interest in accordance with an agreed repayment schedule. Equity finance is money received from an investor in exchange for a percentage of the business. Investors or “equity partners” usually do not expect a return on their investment for three to five years, but often exit after five to seven years.

Table 3: A comparison of debt versus equity funding

Parameter	Debt	Equity
Requirements	Profitability and collateral	High growth potential and reach
Effort	Time required for the application process	May take months to find and convince investors
Ownership	The borrower retains 100% ownership	The borrower must give up a percentage of the ownership and potentially controlling interest
Rates	Interest may be high and repayment begins almost immediately	There is no pressure to make early returns, but returns are generally greater than the interest incurred on equivalent debt financing
Predictability	The repayment amounts and schedule are known	Unpredictable exit of the investor
Oversight	Minimal oversight	Investors need reporting and may get involved in decision-making
Cash Flow	Loan payments decrease net cash flow	No repayment of the cash; the cash is invested straight into the business
Lender’s Stake	Often has little stake in the success of the business	Is very interested in success of the business

Some key advantages of debt financing are that the interest on loans is usually less than the return on equity investments and is tax deductible; however, the borrower is burdened with regular principal and interest payments regardless of how well the business is doing. Equity financing avoids need to repay any capital but requires giving up some control of the company and imposes an increased reporting burden on the company.

PREQIN (www.preqin.com) is an important source of information on private equity and debt investors. Its database has more than 500,000 contacts, including 3,856 active natural resources

investors, 3,749 active infrastructure limited partnerships (LP), 3,822 active Private Debt investors, and 7,835 active Private Equity LPs (Sick 2019).

Bonds are another means to finance a project. A bond is a fixed-income instrument in which an investor loans money to an entity (corporate or governmental) that borrows the funds for a defined period of time at a fixed interest rate. Green Bonds are bonds dedicated to qualifying climate and environmental projects. They are typically asset linked and backed by the issuer's balance sheet. According to James Chen at Investopedia (2019), Green Bonds come with tax incentives, such as tax exemption and tax credits, rendering them a more attractive investment than a comparable taxable bond. This provides a monetary incentive to tackle prominent social issues, such as climate change and a movement to renewable sources of energy. To qualify for Green status, a proposed bond issue is verified by a third party, such as the Climate Bond Standard Board, which certifies that the bond will fund projects that include benefits to the environment. Green Bonds generally are not given to fossil fuel producers especially if the GHG mitigation measure is regarded as a means of extending the life of a fossil fuel project. The only oil and gas projects that potentially qualify would be those involving conversion to renewables (for example, using solar panels to power instruments) and those aimed at managing fugitive emissions. Other potential options include Sustainability Bonds and Social Bonds.

Sustainability Bonds are bonds with proceeds exclusively applied to finance or refinance a combination of both green and social projects. The International Capital Market Association (ICMA) has published Sustainability Bond Guidelines (SBG), as well as Green Bond Principles (GBP) and Social Bond Principles (SBP), available at <https://www.icmagroup.org/>. Social Projects may have environmental co-benefits, and certain Green Projects may have social co-benefits.

2.4.3 Partnerships

An operator (or resource owner) may consider participating in a corporation or other entity with third parties for the purpose of implementing and operating a specific GHG mitigation project or group of projects. This approach possibly would avoid any debt burden by the operator. The operator, as the owner of the produced hydrocarbons, could contribute waste natural gas to a new entity formed with the third party or parties and receive proceeds from the products produced and sold by that entity. The new entity would assume all financing and operating risks as an independent entity. This avoids need for the operator to obtain financing directly. Incorporating a new entity also would facilitate entry of different specialized investors interested in reduction of GHG emissions by allowing them to participate directly in the created entity.

There are three types of partnerships: general, limited, and joint venture. In a general partnership, each partner shares proportionately in the workload, liability, and profits generated. Limited partnerships allow outside investors to buy into a business but maintain limited liability and involvement, based on their contributions. Although a more complicated form of partnership, limited partnerships offers more flexibility in terms of ownership and decision-making. Joint ventures are for short-term projects or alliances. If the venture performs well, it is continued as a general partnership; otherwise, it is dissolved.

Some countries have signed international treaties pertaining to foreign investment that provide certainty and protection to foreign investors. Some countries offer concessions specifically aimed at advancing certain types of GHG mitigation projects (for example, royalty holidays and duty waivers on equipment imported for green projects).

2.4.4 Third-Party Agreements

There are three main types of third-party agreements that may be considered as a form of project financing: concession, sales, and service.

2.4.4.1 Concession Agreement

A concession agreement may take many different forms, such as BOT (build-operate-transfer), BOOT (build-own-operate-transfer), BLT (build-lease-transfer), and DBOT (design-build-operate-transfer). All concession agreements involve a private entity receiving a concession from the operator (resource owner) to finance, design, construct, and operate facilities defined in the agreement in return for the private entity realizing a satisfactory internal rate of return for its investment. At the end of the concession period, the asset is transferred to the operator at no cost. The private entity typically creates a special-purpose entity that enters into the concession agreement, and that entity often obtains debt financing for the project. The special-purpose entity then subcontracts a third party to perform its obligations under the concession agreement. A supply contract is established as part of this agreement to ensure that the project has the necessary access to the waste natural gas stream during the concession period.

2.4.4.2 Sales Agreement

Under a sales agreement, the operator transfers the waste natural gas to a third party who is then required to design and install all the equipment needed to capture and commercialize the resource. This is a form of build-own-operate (BOO) agreement. The operator would sell the raw (unprocessed) natural gas to the third party at the source and allow the third party to perform, by its own means, any activity required to capture and commercialize the natural gas. Ownership of the natural gas is transferred to the third party after establishment of the fiscal point for quantification of natural gas for tax and royalty purposes. The operator is responsible for paying those fees but obtains the benefit of the revenues received from sale of the natural gas to the third party. The operator does not have to transfer ownership of any of its assets other than the natural gas and does not have to invest any money.

The third party assumes the full burden of the project's capital and operating costs, as well as responsibility for converting the raw natural gas into a marketable product or products and getting them to market. However, the third party realizes the full benefit from the sale of those products.

2.4.4.3 Service Agreement

Under a service agreement, another type of BOO arrangement, the operator receives an integral service from a third party in exchange for a fee to manage natural gas losses and avoidable

system inefficiencies. Examples include implementing a gas conservation scheme, utilizing waste gas to reduce the operator’s purchase of fuel and electricity, installing vapour and waste heat recovery systems, and managing fugitive emissions and avoidable system inefficiencies.

The operator does not have any liability to other parties for implementation and ongoing operation of the project other than payment of the service fee.

The third party has the burden of securing all necessary finance for the project, but in return, obtains a long-term service agreement that allows it to cover its operating costs and realize a reasonable rate of return on its investment.

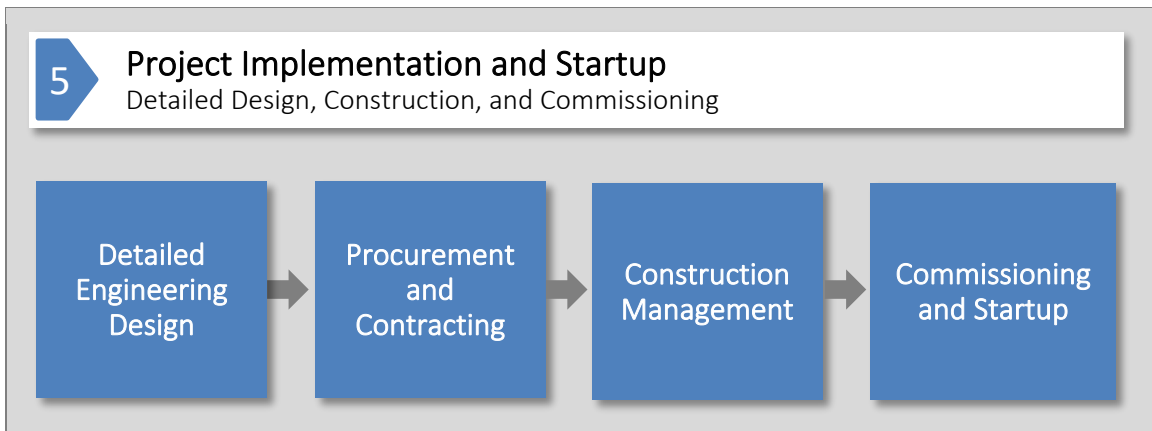
If the operator’s ability to pay service fees is in question, possible solutions include provisions for in-kind payments and earmarking a portion of the savings or revenues generated by the project for payment of the service fee. If reliability of the upstream operation is uncertain, a take or pay provision may be considered. This allows the service provider to secure a regular income for making available certain infrastructure, even when the consumer does not use or require the service.

2.5 Project Implementation and Start-up

This stage of a project development and implementation cycle includes the following activities as depicted on Figure 6:

- Detailed Engineering Design.
- Procurement and Contracting.
- Construction Management.
- Commissioning and Start-up.

Figure 6: Key Elements of the Project Implementation and Startup Stage



2.5.1 Detailed Engineering Design

The detailed engineering design is the engineering stage that follows the FEED. The design’s purpose is to define all technical details of the project, including civil, structural, piping,

electrical, and instrumentation. During this phase, the Control Budget Cost Estimate for the project is identified based on complete equipment requirements and detailed material take-offs.

2.5.2 Procurement and Contracting

This is the competitive process of sourcing and contracting all required materials, equipment, instrumentation, and services for construction, commissioning, and startup phases. Documents generated during procurement and contracting include requests for quotations and bids, bid evaluations, purchase orders, and services contracts.

2.5.3 Construction Management

Construction management is a professional service that oversees planning and construction of a project. This includes inspection and management of the purchased equipment, instrumentation, and materials at the vendor's facility or as these arrive on site. Construction management also includes coordination with civil, mechanical, electrical, instrumentation, painting, and safety contractors, and assurance of compliance with the engineering design and quality standards.

2.5.4 Commissioning and Start-up

Commissioning and Startup is the phase between construction completion and commercial operations. It encompasses all activities that bridge these two phases including systems turnover, checkout of systems, commissioning of systems, introduction of feedstock, and performance testing. Additional information regarding commissioning and start-up is available from the Construction Industries Institute (<https://www.construction-institute.org/resources/knowledgebase/knowledge-areas/commissioning-and-startup>).

2.6 Generation of Carbon or GHG Offset Credits

A carbon credit is a permit that allows a country or organization to produce a certain amount of carbon emissions, which can be traded if the full allowance is not used.

A carbon offset is a reduction in emissions of carbon dioxide (CO₂) or other greenhouse gases to compensate for emissions elsewhere. Offsets are measured in tonnes of carbon dioxide equivalent (CO₂e).

Requirements for generating marketable carbon credits and offsets depend on the market. All cases involve a strong emphasis on transparency and accuracy to the standards of commercial transactions. A formal project design document must be prepared that describes the method or technology to be applied to generate emission reductions, monitoring and calculations to quantify the amount of these reductions, and quality assurance (QA)/QC measures to be applied. Finally, there are requirements for independent validation of the plan by an accredited third party and ongoing verification of reduction claims, usually by a different accredited third party.

Where project financing has been provided, the investors will usually require, as a QA/QC measure, ongoing technical oversight by a qualified third-party advisor of their choosing.

Under the previous Kyoto market, there was a particular emphasis on additionality and management of project leakage. Additionality is the criterion used to assess whether a project results in GHG reductions or removal enhancements in addition to what would have occurred in its absence. Each market provides specific tests to be applied in determining additionality. Project leakage refers to market transformation or activity shifting resulting from the project. Leakage may be either positive (good) or negative (bad).

Article 6 of the 2015 Paris Agreement provides an opportunity to expand the reach of carbon pricing to enable full implementation of Nationally Determined Contributions (NDC) (https://www.ieta.org/resources/UNFCCC/IETA_Article_6_Implementation_Paper_May2016.pdf). Article 6 has two key features (International Emissions Trading Association [IETA] 2016):

1. It describes use of internationally transferred mitigation outcomes (ITMO).
2. It establishes a mechanism to contribute to mitigation of GHG emissions, or an Emissions Mitigation Mechanism (EMM), and to support sustainable development.

The EMM, in conjunction with the ITMO, could be designed to promote carbon pricing. With full implementation of the Paris Agreement, the EMM could offer a universal carbon allowance or credit to those countries choosing to use it, thereby facilitating trade between NDCs (ITMO), providing registry facilities, and offering the prospect of carbon pricing in many economies (IETA 2016). This in turn could channel additional investment.

The term Measurement, Reporting, and Verification (MRV) originally came from the Bali Action Plan in 2007. The basic understanding of the Bali Action Plan is that climate change mitigation actions (mainly GHG emissions reductions) will be implemented in a “measurable, reportable, and verifiable” manner. The key function of MRV is enhancing transparency by tracking national GHG emission levels and climate finance flows received or the impact of mitigation actions.

MRV requirements for ITMOs are still evolving; however, examples exist from the established carbon trading programs (see Table 4). In all cases, requirements for carbon credits are to be consistent with accuracies, accounting, and transparency principles for fungible commodities.

Table 4: Examples of established GHG emission offset programs

Jurisdiction	Program	Web Site	Information Available
Alberta, Canada	Alberta Emissions Offset System	https://www.alberta.ca/alberta-emission-offset-system.aspx	<ul style="list-style-type: none"> • Standards and Guidance • Quantification Protocols
Australia	National Carbon Offset Standard	http://www.environment.gov.au/climate-change/government/carbon-neutral/ncos	<ul style="list-style-type: none"> • Best-practice guidance on how to measure, reduce, offset, report, and audit emissions. • Carbon Neutral Certification.
California, USA	California Air Resources Board (CARB)	https://www.arb.ca.gov/cc/capandtrade/offsets/offsets.htm	<ul style="list-style-type: none"> • Early Action Offset Program Guidance • Attestations • Compliance Offset Protocols

Jurisdiction	Program	Web Site	Information Available
	Compliance Offset Program		<ul style="list-style-type: none"> • Compliance Offset Projects • Offset Project Registries • Offset Verification Program
European Union (EU)	EU Emission Trading System (ETS)	https://ec.europa.eu/clima/policies/ets_en	<ul style="list-style-type: none"> • EU ETS Legislation • Carbon Market Reports • Implementation • Application of value added tax (VAT)
Selected U.S. States and Canadian Provinces	Western Climate Initiative	http://www.wci-inc.org/	<ul style="list-style-type: none"> • Program Design

3 Mitigation Opportunities to Assess: #1 Storage Tanks

Production and processing facilities are often equipped with one or more atmospheric tanks for temporary storage of produced hydrocarbon liquids (oil or condensate) and water (see Figure 7). If these tanks are vented to the atmosphere, they are sources of storage losses (that is, the product is lost to the atmosphere due to evaporation effects). The amount and type of emissions normally depend on the composition of the stored product, its vapour pressure, storage conditions, and the amount of liquid level movement in the tank. In tanks containing hydrocarbon liquids, the true vapour pressure of the product at storage conditions should be well below atmospheric pressure to avoid boiling or flashing losses.

Figure 7: Photograph of hydrocarbon and produced water storage tanks at a production facility



Depending on the amount of evaporation loss and the value of the product, it may become economical to install vapour controls. Vapour controls may have been uneconomical when the facility was first designed, but this situation may have changed over time due to the rising value of oil and natural gas. In addition, process conditions may have changed, resulting in greater evaporation losses than intended.

Methane emissions from storage tanks occur where one or more of the following conditions apply: (1) the liquid hydrocarbons has been in direct contact with natural gas in a pressurized vessel immediately prior to entering the atmospheric storage tank (that is, some of the natural gas will have dissolved in the liquid hydrocarbons and will flash out upon entering the storage tank); (2) the tank is equipped with a natural gas blanketing system designed to vent directly to the

atmosphere or is subject to operational problems; and (3) unintentional gas carry-through to the tanks occurs (for example, due to failure of the upstream dump-valve to seat properly, formation of a vortex during dumping events).

3.1.1 Recommended Checks

Emission rates from all atmospheric storage tanks containing process liquids (produced oil, condensate, or water) should be measured, and the value of conserving these vapours determined. Furthermore, the cause of any emission contributions exceeding normal design (or intended) evaporation losses should be determined and resolved. Specific emission contributions on which to focus are as follows: Flashing Losses, Unintentional Gas Carry-Through to Storage Tanks, Malfunctioning Gas Blanketing System, and Undersized Vapour Recovery Units.

3.1.1.1 Flashing Losses

Flashing losses occur when the produced hydrocarbon liquid has a vapour pressure greater than local atmospheric pressure. When this material enters the stock tank, its vapour pressure decreases rapidly toward local atmospheric pressure, and then more slowly as the rate of evaporation stabilizes. The vapour pressure of the incoming product will be equal to the vapour pressure of the first vessel upstream of the tanks (usually 275+ kilopascals [kPa] at oil production facilities and 2000+ kPa at gas production facilities). At oil batteries, this vessel is usually either the inlet separator or the treater. At gas facilities, it is usually the inlet separator or, in the case of compressor stations, the suction and inter-stage scrubbers.

3.1.1.2 Unintentional Gas Carry-through to Storage Tanks

There are various opportunities for unintentional carry-through of natural gas to crude oil storage tanks and may include the following:

- Inefficient separation of gas and liquid phases upstream of the tanks, allowing some gas carry-through (by entrainment) to the tanks. This may occur where inlet liquid production (for example, produced water) has increased significantly over time, resulting in undersizing of a facility's inlet separators under current conditions.
- The liquid-level control valve on the upstream separator may not be seating properly at the end of a dump cycle, allowing the separator to empty to the point of allowing gas to carry through to the storage tank.
- The set point of the liquid-level controller may be too low.
- A manual drain valve may have been left partially or fully open, or may not be seating properly, allowing drainage of liquids from the vessel and carry through of gas to the storage tanks.
- If a purge system is connected to the liquid header, the purge-gas valve may have been left partially or fully open or may not be seating properly.
- Piping changes resulting in unintentional placement of high-vapour-pressure product in tanks not equipped with appropriate vapour controls (for example, routing of liquids from compressor suction and interstage scrubbers directly to atmospheric storage tanks).

- Large volumes of gas may be displaced to storage tanks during pigging operations.

3.1.1.3 Malfunctioning Gas Blanketing System

The purpose of a gas blanketing system is to keep air out of the vapour space and, where the tank is connected to a vapour collection system, prevent an over-vacuum condition. If the system is functioning properly, gas should be flowing into the tank only when the liquid level is falling or a cooling effect occurs (for example, due to a drop in ambient temperature), causing pressure inside the tank to drop below the low-pressure set point of the blanket gas system. The rest of the time, blanket gas flow into the storage tank should be zero.

Malfunctioning or improperly set blanket gas regulators and vapour-control valves can result in excessive blanket gas consumption and, consequently, increased flows to the end control device (for example, vent, flare, or vapour recovery compressor). The blanket gas is both a carrier of product vapours and a potential pollutant itself (that is, natural gas is usually used as the blanket medium for blanketed tanks at gas processing plants).

3.1.1.4 Undersized Vapour Recovery Units

Vapour recovery systems can become undersized due to changes in production levels, and vapour collection lines can become fouled, thereby restricting vapour flow out of the tank. Both situations will contribute to over-pressure conditions in the tank and cause gas to be relieved through the pressure-vacuum relief valve(s) and thief hatch on the roof of the tank. Usually when this occurs, indications of condensation or fouling on the outlets of the pressure-vacuum valves are visible. Moreover, once these conditions begin, the pressure vacuum-relief valves will eventually have trouble seating, causing a continuous loss of blanket gas and vapour.

3.1.2 Measurements

The above emission contributions may be determined by measuring venting rates and comparing observed emissions to calculated working losses under conditions at the time of testing. Refer to Section 5.2 for potential measurement techniques.

3.1.3 Reduction Potential

Tanks at five gas-processing plants (three in the United States and two in Canada) were checked for emissions exceeding normal weathered-product evaporation losses. Two sites showed abnormally high emissions from storage tank vents. Total hydrocarbon emissions in one case amounted to 4.56×10^3 cubic meters per day (m^3/d) (or roughly 0.017 million tons per year [Mt/y] of CO_{2e} emissions based on the CH₄ content of the vapours), and $1.39 \times 10^3 m^3/d$ (0.005 Mt/y of CO_{2e} emissions) in the other case. The average losses over the five sites surveyed amounts to 0.0045 Mt/y of CO_{2e} emissions due to excess venting by storage tanks. Thus, while excess storage losses do not occur at all sites, where losses do occur, the amount of emissions can be significantly large, and consequently, very economical to control. Frequency of such situations is sufficiently high to warrant targeting these sources.

The following is a list of control measures that may be considered:

- Process optimization.
- Pressure-vacuum relief valves.
- Floating decks.
- Vapour control systems.
- Vapour-recovery towers.

The Natural Gas Star program provides additional, more-specific information regarding control technologies applicable to storage tanks, summarized in Table 5.

Table 5: Natural Gas Star documents on cost-effective options for reducing CH₄ emissions from storage tanks

Document Title	Capital Cost (USD)	Estimated Payback	Applicable Industry Segments			
			Production	Gathering and Processing	Transmission	Distribution
Convert Water Tank Blanket from Natural Gas to Produced CO ₂ Gas, PRO Fact Sheet #503 (https://www.epa.gov/natural-gas-star-program/convert-water-tank-blanket-natural-gas-produced-co2-gas).	\$1,000 to \$10,000	0 to 1 year	✓			
Eliminate Unnecessary Equipment and/or Systems, Pro Fact Sheet #504 (https://www.epa.gov/natural-gas-star-program/eliminate-unnecessary-equipment-andor-systems).	\$1,000 to \$10,000	0 to 1 year	✓	✓	✓	✓
Recovery Gas from Pipeline Pigging Operations, PRO Fact Sheet #505 (https://www.epa.gov/natural-gas-star-program/recover-gas-pipeline-pigging-operations).	\$10,000 to \$50,000	0 to 1 year	✓	✓	✓	
Recovery Gas During Condensate Loading, PRO Fact Sheet #502 (https://www.epa.gov/natural-gas-star-program/recover-gas-during-condensate-loading).	<\$1,000	1 to 3 years	✓	✓	✓	

Document Title	Capital Cost (USD)	Estimated Payback	Applicable Industry Segments			
			Production	Gathering and Processing	Transmission	Distribution
Install Pressurized Storage of Condensate, PRO Fact Sheet #501 (https://www.epa.gov/natural-gas-star-program/install-pressurized-storage-condensate).	\$10,000 to \$50,000	1 to 3 years	✓	✓	✓	
Installing Vapor Recovery Units on Storage Tanks, Lessons Learned (https://www.epa.gov/natural-gas-star-program/installing-vapor-recovery-units-storage-tanks).	>\$50,000	1 to 3 years	✓			

Additional emissions mitigation guidance pertaining to petroleum storage tanks containing unstabilized products is provided in the CCAC *Technical Guidance Document Number 6: Unstabilized Hydrocarbon Liquid Storage Tanks* (CCAC 2017f) (<https://www.ccacoalition.org/en/resources/technical-guidance-document-number-6-unstabilized-hydrocarbon-liquid-storage-tanks>).

3.1.3.1 Process Optimization

Several process variables, as well as size and cost of any additional add-on controls that may be required, may be optimized to help minimize storage losses. If flashing losses occur, significant benefit may result from minimizing the following variables:

Vapour Pressure of the Product to be Stored. Three options may be considered for reducing this variable, described as follows:

- Lower operating pressure of the first vessel upstream of the tanks. The initial vapour pressure of the hydrocarbon liquids will be the same as this pressure at most oil and gas field facilities. Some trade-off is likely between increased energy requirements (for example, increased pumping or compression requirements) in other parts of the process and reduced storage losses; however, this option could prove beneficial in many cases.
- Install a vapour recovery tower (or gas boot) (see Section 3.1.3.5) directly upstream of the storage tanks and connect the off-gas line to the flare system. A vapour recovery tower is an elevated two-phase separator operated at just enough pressure to push the vapours into the low-pressure flare system and placed high enough to allow oil flow by gravity into the storage tanks. This approach may eliminate the need to install a costly vapour collection system on the storage tanks.

- Install a stabilizer upstream of the storage tanks. This option may be considered for both crude oil and hydrocarbon condensate storage systems. It is feasible only at sites where the stabilizer off-gas (or overheads) can be conserved or utilized.

Amount of Product to be Stored. At compressor stations, it may be appropriate to pump the hydrocarbon liquids from the scrubbers to the compressor discharge piping rather than to an on-site storage tank. This would allow for more centralized handling of the liquids but may be practicable only where the amount of liquid is relatively small compared to the amount of gas.

This same approach may be considered for use at field dehydrators.; however, care must be exercised. Condensate in the inlet separator contains dissolved water. This water may be enough to cause hydrate problems even though the gas is dehydrated. Dehydration of the condensate also may be necessary.

Peak Emission Rates. The recycling of product back to the treater at oil batteries allows the oil to re-absorb solution gas and thereby increases flashing losses. Consequently, any efforts to reduce the amount of oil recycling will be beneficial. Typically, 10 to 15 percent of the produced oil is recycled, usually in batches. Because any add-on controls possibly required will be sized to handle the maximum emission rate, minimizing the actual pumping rate during these recycle operations would be useful. This same logic applies to batch shipments of oil that may be brought on site by tank truck for treatment or cleaning.

Another possibility is to minimize displacement of vapours from the tank due to rising and falling of the liquid surface (that is, working losses) by properly scheduling filling, emptying, and recycling activities. For example, shipping product from a tank while it is being filled will reduce the net change in the liquid level and amount of working losses.

If the product has been weathered or stabilized prior to storage, no flashing losses will occur, and minimization of the following variables may be helpful:

- **Storage Temperature.** Lowering the temperature of the stored product will reduce vapour pressure of the product and thereby reduce evaporation rates. The storage temperature can be lowered by applying reflective paints to the outside of the tank, decreasing the set point of the tank heaters, and possibly decreasing the set point of any process heaters directly upstream of the tanks.
- **Exposed Liquid Surface Area.** At many older facilities, tanks commonly are oversized for the amount of production. Exchanging these tanks for more appropriate, smaller diameter tanks will reduce standing losses by the percent change in cross-sectional area and reduce working losses to a much lesser extent. This strategy will be most beneficial when applied to tanks with low turnover rates (for example, slop or waste oil tanks).

Potential for reducing emissions through process optimization depends greatly on the age and design of the plant, maintenance and operating practices, training of personnel, and commitment by management.

3.1.3.2 Pressure-Vacuum Relief Valves

A pressure-vacuum valve is a control device used to regulate the outflow of vapours from and the inflow of air to tanks storing products at or near atmospheric pressure. It allows a slight pressure rise or vacuum (usually up to 30 cm of water-column pressure) before opening to allow pressure or vacuum relief to the tank. Once activated, the valve remains open until pressure in the tank is within the limits of its high and low set points.

In addition to protecting the tank from any damaging effects of overpressure or over-vacuum, the control action helps to inhibit certain types of evaporation loss, namely standing losses, and to a lesser extent, working losses. This provides little control of emissions in cases of significant flashing losses or deficient vapour tightness of the tank.

3.1.3.3 Floating Decks

A floating deck is an impermeable, plate-like structure that rests freely on the liquid surface. It reduces storage losses by providing a barrier to evaporation from the liquid surface.

Automatic bleeder vents are used on the deck to prevent gas from accumulating under it (for example, solution gas or slugs of gas from the pipeline), as this could cause the deck to tilt and bind or possibly collapse and sink. These vents also serve to equalize the pressure of the vapour space across the deck, when the deck is either landed on or floated off its supports. Legs or suspended cables are used to hold the deck a predetermined distance off the tank bottom to prevent damage to fittings underneath the deck and to allow for tank cleaning or repair.

Because of the use of bleeder vents and the need to operate the tanks near atmospheric pressure, a floating deck is effective only in reducing standing and working losses; it does not prevent flashing losses. Usefulness of a floating deck is therefore limited to applications involving products with a true vapour pressure below local atmospheric pressure (for example, weathered or stabilized products).

Effectiveness of a floating deck (excluding flashing losses) is determined by how well the deck maintains a vapour-tight barrier across the liquid surface. Typically, losses result from evaporation in gaps between the tank wall and the perimeter of the deck, and through any bolted seams or fittings that penetrate the deck. Any liquid that clings to the walls as the deck descends during the removal of product is subject to evaporation. Sealing and wiping mechanisms help reduce these losses, but radial variances in tank shape and the nature of deck fittings significantly lower possibility of a completely vapour-tight seal.

Problems could arise during use of floating roof tanks to store heavy, waxy crudes. The solid wax tends to adhere to the shell as the deck is lowered, and then melts and runs onto the roof and sealing mechanism as the tank walls heat during the day. This can pose a fire hazard and foul some fittings on the deck. Also, if hard seals are used, these can scrape wax from the walls onto the deck to aggravate the situation, or they may cause the deck to bind in the presence of a wax buildup. However, potential for these problems is much greater on external floating roofs because they are more susceptible to fouling and necessitate use of more rigid seals than do internal floating roofs (EPA 1987).

In the event of these problems, internal floating roof tanks may be insulated and equipped with steam coils to keep the wax in solution; however, this results in higher operating costs and requires a source of steam.

3.1.3.4 Vapour Collection and Control System

Vapour collection and control systems (VCCS) collect and recover or dispose of vapours from the stored product. They can also help reduce evaporation at the liquid surface by aiding maintenance of high concentrations of hydrocarbon vapour above the liquid. It is possible that less vapour would be present than under freely vented conditions. VCCSs may be considered for all storage applications but are particularly suited to those involving significant flashing losses.

An important consideration in the design of any VCCS is the potential for condensation in the vapour collection piping. Normal practice is to design vapour collection piping so that it slopes to a knockout drum, where any condensate can accumulate and be removed. Also important is use of corrosion-resistant material for the piping (for example, plastic, stainless steel, or internally coated carbon steel). Carbon steel piping without any internal coating is susceptible to corrosion in these applications. Resulting corrosion products may build up in the piping and restrict flow by fouling devices, such as flame or detonation arrestors. In northern climates, if pipe-rack supports are not designed to preclude frost heave, the pipe rack can lose its initial vertical alignment and cause low spots where liquids can accumulate and restrict vapour flow.

Additionally, any condensation that may form in the vapour collection system can be very volatile and difficult to pump. Consequently, a blow case system may be necessary to transfer the liquids back to the stock tanks or other appropriate storage containers.

Typical performance standard for vapour control systems is a minimum control efficiency of 95 percent.

3.1.3.5 Vapour Recovery Towers

A vapour recovery tower is a vertical vessel designed to release and remove any gas that may be in solution or entrained in the hydrocarbon liquid to be stored. It is located immediately upstream of the receiving tank or tanks. The gas line off the top of the vessel is connected directly to the vapour collection system. The liquid line off the bottom is connected directly to the stock tanks. Some vessels are equipped with several trays to promote complete flashing of the solution gas.

Design operating pressure of the vapour recovery tower is near local atmospheric conditions, and slightly greater than for a stock tank vapour collection system (for example, 15 to 30 centimeters of water column pressure). The design shut-in pressure of the vessel is usually about 40 kPa. Consequently, the vessel can be operated over a much wider range of pressures than can stock tanks, and it is much less susceptible to damage in the event of a system upset or malfunction. Actual vessel operating pressure depends on the amount of friction losses through the vapour collection piping, as well as the suction pressure and capacity of the control device.

To eliminate any need for pumps, the vessel is either elevated a sufficient distance above the ground or is made tall enough for the liquid to flow by gravity into the stock tanks. It must

usually be at least 5 meters taller than the stock tanks to overcome friction losses in the connecting piping and check valve.

Hydrocarbon liquid enters the boot with a true vapour pressure of about 250 to 400 kPa (that is, the absolute operating pressure of the next upstream vessel, namely the treater or inlet separator), and leaves with a true vapour pressure of about 90 to 100 kPa (that is, about local atmospheric pressure). Therefore, the product to be stored is still quite volatile. The use of a gas vapour recovery tower does not necessarily preclude the need for some form of emission control on the stock tanks. Advantages of the vapour recovery tower are that it is simple, protects the tanks from possible pressure damage caused by sudden unexpected gas slugs, and can be less costly to implement if many tanks connect to the vapour collection system.

A limitation of the vapour recovery tower is its ineffectiveness in releasing solution gas from heavy viscous oils, particularly crude bitumen (that is, residence time is not long enough to achieve vapour-liquid equilibrium).

4 Mitigation Opportunities to Assess: #2 Fugitive Equipment Leaks

Fugitive equipment leaks (Figure 8) are unintentional leaks from equipment components including, but not limited to, valves, flanges, and other connections, pumps, compressors, pressure relief devices, process drains, open-ended valves, pump and compressor seal system degassing vents, accumulator vessel vents, agitator seals, and access door seals. Once a leak starts, it tends to remain a continuous source of emissions until repaired.

Figure 8: Photograph showing tagged fugitive equipment leaks at a gas processing facility



Some noteworthy trends and considerations pertaining to leaks are as follows:

- Components on fuel gas systems tend to leak more than components on process gas systems. The leaks likely reflect a lower level of care and attention and lower quality components in fuel gas applications.
- Potential for leaks tends to decrease as the value or toxicity of the process fluid increases, and where gas has been odorized. Thus, leak frequencies for equipment components in sour service are much lower than for components in sweet service. At sour gas plants, often only a small portion of the plant is actually in sour service.
- Stem packing on control valves tends to leak more than on block valves.

- A hydra-mechanical governor³ on a compressor engine tends to be the most leak-prone component in control valve service. Average leak rate of these is 0.479 kilograms per hour (kg/h) per source compared to 0.049 kg/h per source for other control valves and 0.011 kg/h per source for block valves.
- Components tend to have greater average emissions when subjected to frequent thermal cycling, vibrations, or cryogenic service.

4.1 Recommended Checks

A good practice is to include a comprehensive leak survey as part of the review because these emissions are often the easiest and most cost-effective to control, and usually do not require any capital expenditures. Moreover, leaks are more apt to pose a safety issue than other types of opportunities highlighted in this guide.

4.1.1 High-Risk Sources

It is important to recognize that different types of components in different service applications will have different leak potentials (that is, different probabilities of leaking and different average leak rates when they do leak). Usually, most emissions from fugitive equipment leaks at a facility come from a few big leakers rather than many smaller leakers. While in theory any component could be a big leaker, the most probable sources of these big leaks include:

- Compressor seal vents.
- Pressure relief valves.
- Leakage into intermittent vent or flare systems.
- Leaking pressure vacuum relief valves, thief hatches, and gauge well covers on storage tanks equipped with gas blanketing.

Accordingly, these components merit the greatest attention. This is reflected in Table 6, which lists sample statistics of a gas transmission system. Valves and connectors make up most of the component population (97.96 percent) but contribute a relatively small portion of the total emissions (13.0 percent), while open-ended lines, blowdown systems, and compressor seals make up a very small portion of the component population (1.7 percent) but contribute 86.7 percent of the total emissions.

The components that have the greatest leak potential are often the ones that are most difficult to access, and thus are most likely to be excluded from a leak survey—resulting in a missed significant control opportunity. It is important to make advance arrangements with the facility to provide any special assistance possibly needed to access high-potential leak sources. Ultimately,

³ The engine governor controls engine speed, and in some generator applications, generator load. Hydra-mechanical governors sense engine speed mechanically and use the engine's oil pressure to hydraulically move the actuator controlling fuel flow to the cylinders.

facilities should move toward installing easy-access monitoring ports, sample lines, or permanent instrumented monitoring solutions to facilitate easy self-monitoring of these components.

Table 6: Sample leak statistics for a gas transmission facility

Major Category	Sub-Category	Typical Leak Frequency (%)	Portion of Component Population (%)	Contribution to Total Leakage (%)
Connectors	All	1.21	87.33	6.06
Valves	Control Valves	14.65	0.27	1.34
	Block Valves	3.98	10.36	5.63
Open-Ended Lines	All	N/A	1.33	28.27
Pressure Relief Devices	All	14.65	0.20	14.21
Pressure Regulators	All	16.28	0.30	0.25
Blowdown Systems	Pressurized Station or Compressor Unit	73.53	0.08	18.38
	Depressurized Reciprocating Compressor	73.33	0.00	0.00
	Depressurized Centrifugal Compressor	61.11	0.00	0.00
Compressor Seals	Reciprocating Compressor	86.11	0.06	10.62
	Centrifugal Compressor	95.23	0.07	15.24
Flow Meters	Orifice Meters	20.19	0.00	0.00
	Other	2.63	0.00	0.00
All	All	100	100.00	100.00

Source: Based on data from measurement programs sponsored by Canadian Energy Partnership for Environmental Innovation (CEPEI) in 2007 and prior years.

The following are special considerations when checking selected high leak potential components:

- Leakage from a compressor blowdown system is less when the compressor is pressurized than when it is depressurized. In the pressurized case, leakage occurs only past the seat of the blowdown valve. In the unpressurized case, leakage occurs past the seats of the upstream and downstream unit block valves.
- When checking compressor seals, it is important to check the packing case, distance piece, and lube oil drain tank (or degassing reservoir) vents for emissions.

- Compressors that feature a seal-gas recovery system normally are designed with a pressure-relief vent for discharging any seal-gas flows exceeding the capacity of the seal-gas recovery system. These vents and the compressor crankcase vent (that is, on reciprocating compressors) should be checked for leaks.

4.1.2 Low-risk Components

Low-leak-potential components such as connectors and valve stem packing systems are less likely to be sources of big leaks, but occasionally can be major leak sources. Examples of situations of this or possibly other unexpected significant leak contributions include the following:

- Connections left untightened after a plant turnaround or maintenance that go unnoticed due to high background noise levels or because the component is at a difficult-to-access or infrequently visited location (for example, at high elevation locations or on a pipe rack)
- Holes that have developed in equipment or piping due to corrosion, abrasion, or damage
- Components improperly installed or not installed (for example, a pressure gauge removed during maintenance work was not put back into its monitoring port, and the valve on the port is in an open or partially open position)
- A major failure of a valve stem packing system (for example, blowout of the packing material).

Accordingly, surveys of low-leak-potential components are recommended.

4.2 Measurements

Methane leaks are detected during formal leak surveys using US EPA Method 21 techniques (EPA 2017) (<https://www.epa.gov/emc/method-21-volatile-organic-compound-leaks>) and use of optical gas imaging (OGI) infrared cameras guided by the EPA's *Alternative Work Practice (AWP) to Detect Leaks from Equipment* (EPA 2008) (<https://www.federalregister.gov/documents/2008/12/22/E8-30196/alternative-work-practice-to-detect-leaks-from-equipment>). Additional guidance is provided in the EPA (2007) report titled *Leak Detection and Repair: A Best Practices Guide* (<https://www.epa.gov/compliance/leak-detection-and-repair-best-practices-guide>).

EPA Method 21 allows use of handheld gas sensors and bubble tests to detect leakage points on process equipment causing fugitive emission to the atmosphere. The survey team must come into direct contact with the components surveyed, but some components escape survey because they are inaccessible. Also, unexpected leakage points go unchecked (for example, cracked welds, corrosion or abrasion holes, mechanical damage points).

OGI cameras are less sensitive than Method 21 techniques but allow equipment components to be surveyed much more quickly and survey inaccessible components from a short distance. A comparison of the two approaches is provided in the EPA 2015 Natural Gas STAR Annual Implementation Workshop presentation by T. Trefiak of Target Emissions titled *LDAR Case*

Study Comparison of Conventional Method 21 Vs Alternative Work Practice (US EPA 2015) (<https://www.epa.gov/natural-gas-star-program/ldar-case-study-comparison-conventional-method-21-vs-alternative-work>). This presentation shows that, despite its lower sensitivity, the OGI camera is more effective at finding leaks—particularly the bigger leaks that contribute most of the emissions and unexpected leakage points. Moreover, costs of OGI surveys tend to be 28 percent less than costs of Method 21 surveys.

Newer techniques involving use of drones and remote sensing are under development. These are more likely to be effective for whole facility screening to determine which sites to target for detailed alternative work practices (AWP) or Method 21 surveys.

Leak quantification allows rank ordering of detected leaks for repair purposes, an economic analysis of individual repairs, and monitoring of overall effectiveness of a leak detection and repair (LDAR) program over time. Techniques applied to quantify leaks include the Hi-Flow Sampler and bagging. Leakage into vent and flare systems may be quantified by application of the techniques discussed in Section 5.2.

Some additional information on leak detection and quantification techniques is provided in the CCAC report titled: *Conducting Emissions Surveys, Including Detection and Quantification Equipment (Appendix A of the OGMP Technical Guidance Documents)* (CCAC 2017j) (<https://www.ccacoalition.org/en/resources/conducting-emissions-surveys-including-emission-detection-and-quantification-equipment>).

The Canadian Association of Petroleum Producers (CAPP) has developed a Best Management Practice (BMP) report titled *Management of Fugitive Emissions at Upstream Oil and Gas Facilities*, January (CAPP 2007) (<https://www.capp.ca/publications-and-statistics/publications/116116>) for detection, measurement, and management of fugitive emissions at oil and gas facilities. CAPP also provides a BMP for Pipeline Leak Detection Programs (CAPP 2018) (<https://www.capp.ca/publications-and-statistics/publications/310502>).

4.3 Reduction Potential

Field studies have shown that pursuing leak control opportunities with a 1-year payback or better can reduce fugitive emissions by 70 percent or more. Any leak that can be readily repaired should be repaired; however, the focus should clearly be on finding and controlling the few big leaks at sites.

A good practice is to survey all components annually and survey high-leak-potential components at sufficiently greater frequencies to manage their greater risk. Additionally, individual equipment components that have undergone repairs, servicing, or replacement, or that have been disassembled should be checked for leaks after return to pressurized service.

Where repair of a leaking equipment component has been delayed, for whatever reason, the component should be monitored at least monthly, and at such greater frequencies as may be needed to ensure that the situation does not, at any time, pose an occupational health or safety concern. Monitoring should include, at a minimum, determining that the leak does not cause any high percent-LEL alarm conditions in unclassified areas (for example, as determined by use of a personal monitor or other combustible gas detector).

Table 7 presents guidance on conducting directed inspection and maintenance programs at different types of facilities.

Table 7: EPA Natural Gas STAR documents on conducting directed inspection and maintenance

Document Title	Capital Cost (USD)	Estimated Payback	Applicable Industry Segments			
			Production	Gathering and Processing	Transmission	Distribution
Conduct Directed Inspection and Maintenance at Remote Sites, PRO Fact Sheet #901 (https://www.epa.gov/natural-gas-star-program/conduct-directed-inspection-and-maintenance-remote-sites).	<\$1,000	0 to 1 year			✓	✓
Directed Inspection and Maintenance at Gate Stations and Surface Facilities, Lessons Learned (https://www.epa.gov/natural-gas-star-program/directed-inspection-and-maintenance-gate-stations-and-surface-facilities).	\$1,000 to \$10,000	0 to 1 year			✓	✓
Directed Inspection and Maintenance at Compressor Stations, Lessons Learned (https://www.epa.gov/natural-gas-star-program/directed-inspection-and-maintenance-gate-stations-and-surface-facilities).	\$10,000 to \$50,000	0 to 1 year			✓	✓
Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations, Lessons Learned (https://www.epa.gov/natural-gas-star-program/directed-inspection-and-maintenance-gas-processing-plants-and-booster).	\$10,000 to \$50,000	1 to 3 years		✓		

AVO inspections by site personnel should occur regularly as a leak detection measure between formal leak surveys—inside and outside each active process building, around all process units, and along all aboveground piping to check for signs of the following:

- Frosting or sweating of valves and pressure relief devices connected to vent lines.
- Visible vapor or steam plumes or dripping from equipment components.
- Normally closed valves connected to vents or open-ended lines not fully closed during normal operations.
- Components (for example, covers, plugs, pressure gauges) that have been temporarily removed for inspection, maintenance, or other purposes, and not put back in place afterwards.
- Unlit pilots on fired equipment (for example, line heaters) and unlit flares.
- Odors inside buildings and downwind of piping and process equipment.
- Sounds indicative of a leak.

AVO inspections may be recorded either as additions to existing operator check sheets or on preventative-maintenance forms that indicate when AVO inspections occurred.

Table 8 summarizes information provided by the EPA Natural Gas Star program regarding control technologies applicable to different types of fugitive equipment leaks.

Table 8: EPA Natural Gas Star documents on cost-effective options for controlling different types of fugitive equipment leaks

Document Title	Capital Cost (USD)	Estimated Payback	Applicable Industry Segments			
			Production	Gathering and Processing	Transmission	Distribution
Wet Seal Degassing Recovery System for Centrifugal Compressors, PRO Fact Sheet (https://www.epa.gov/natural-gas-star-program/wet-seal-degassing-recovery-system-centrifugal-compressors).	\$33,000 (1 compressor) \$90,000 (4 compressors)	0 to 1 year	✓	✓	✓	
Reducing Methane Emissions from Compressor Rod Packing Systems, Lessons Learned (https://www.epa.gov/natural-gas-star-program/reducing-methane-emissions-compressor-rod-packing-systems).	\$1,000 to \$10,000	0 to 1 year	✓	✓	✓	

Document Title	Capital Cost (USD)	Estimated Payback	Applicable Industry Segments			
			Production	Gathering and Processing	Transmission	Distribution
Test and Repair Pressure Safety Valves, PRO Fact Sheet #602 (https://www.epa.gov/natural-gas-star-program/test-and-repair-pressure-safety-valves).	<\$1,000	0 to 1 year	✓	✓	✓	✓
Eliminate Unnecessary Equipment and/or Systems, PRO Fact Sheet #504 (https://www.epa.gov/natural-gas-star-program/eliminate-unnecessary-equipment-andor-systems).	\$1,000 to \$10,000	0 to 1 year	✓	✓	✓	
Replace Compressor Cylinder Unloaders, PRO Fact Sheet #106 (https://www.epa.gov/natural-gas-star-program/replace-compressor-cylinder-unloaders).	\$10,000 to \$50,000	1 to 3 years	✓	✓	✓	
Replacing Wet Seals with Dry Seals in Centrifugal Compressors, Lessons Learned (https://www.epa.gov/natural-gas-star-program/replacing-wet-seals-dry-seals-centrifugal-compressors).	>\$50,000	1 to 3 years	✓		✓	
Install BASO Valves, PRO Fact Sheet #604 (https://www.epa.gov/natural-gas-star-program/install-baso-valves).	<\$1,000	0 to 1 year	✓			
Perform Valve Leak Repair During Pipeline Replacement, PRO Fact Sheet #601 (https://www.epa.gov/natural-gas-star-program/perform-valve-leak-repair-during-pipeline-replacement).	\$1,000 to \$10,000	0 to 1 year			✓	✓
Replace Burst Plates with Secondary Relief Valves, PRO Fact Sheet #605 (https://www.epa.gov/natural-gas-star-program/replace-burst-plates-secondary-relief-valves).	\$1,000 to \$10,000	0 to 1 year	✓	✓	✓	
Install Excess Flow Valves, PRO Fact Sheet #603 (https://www.epa.gov/natural-gas-star-program/install-excess-flow-valves).	\$1,000 to \$10,000	3 to 10 years				✓

Additional guidance for managing emissions from compressor seals and other types of fugitive equipment leaks is available in the following CCAC documents:

- *Technical Guidance Document Number 2: Fugitive Component and Equipment Leaks* (CCAC 2017b) (<https://www.ccacoalition.org/en/resources/technical-guidance-document-number-2-fugitive-component-and-equipment-leaks>).
- *Technical Guidance Document Number 3: Centrifugal Compressors with “Wet” (Oil) Seals* (CCAC 2017c) (<https://www.ccacoalition.org/en/resources/technical-guidance-document-number-3-centrifugal-compressors-%E2%80%9Cwet%E2%80%9D-oil-seals>).
- *Technical Guidance Document Number 4: Reciprocating Compressors Rod Seal/Packing Vents* (CCAC 2017d) (<https://www.ccacoalition.org/en/resources/technical-guidance-document-number-4-reciprocating-compressors-rod-sealpacking-vents>).

5 Mitigation Opportunities to Assess: #3 Vent and Flare Systems

Flare and vent systems exist in essentially all segments of the oil and gas industry and are used for two basic types of waste gas disposal: intermittent and continuous. Intermittent applications may include disposal of waste volumes from emergency pressure-relief episodes, operator-initiated or instrumented depressurization events (for example, depressurization of process equipment for inspection or maintenance purposes, or depressurization of piping for tie-ins), plant or system upsets, well servicing and testing, pigging events, and routine blowdown of instruments, drip pots, and scrubbers. Continuous applications may include disposal of the following:

- Associated gas and vapours from storage tanks at oil production facilities where gas conservation is uneconomical or until such economics can be evaluated.
- Casing gas at heavy oil wells.
- Process waste or byproduct streams that either have little or no value or are uneconomical to recover (for example, vent gas from glycol dehydrators, acid gas from gas sweetening units, and sometimes stabilizer overheads).
- Vent gas from gas-operated devices where natural gas is used as the supply medium (for example, instrument control loops, chemical injection pumps, samplers).

An example of a commonly used, un-enclosed flare at an upstream oil and gas facility appears on Figure 9.

Typically, waste gas volumes are flared if they pose an odor, health, or safety concern, and otherwise are vented.

5.1 Recommended Checks

5.1.1 Continuous Venting or Flaring

Continuous vents or flares should be reviewed to accurately determine the amount of gas to be disposed and whether current market conditions now make the gas economical to conserve or utilize. Additionally, sufficient review of the process should occur to determine whether the measured values are consistent with what would be expected and if any unintentional contributions are occurring.

Figure 9: Photograph of a typical flare at an upstream oil and gas facility



5.1.2 Intermittent Venting and Flaring

Key issues with intermittent vent or flare systems include:

- The systems often lack a flow meter or if one is present, it is either unreliable or is sized to monitor peak flows during relief or blowdown events. Low flow readings that occur the rest of the time are usually ignored and treated as meter noise.
- In the absence of any instrumentation, it is difficult to detect excessive residual flows, except in very extreme cases. This is partly because the discharge point is an elevated source and generally inaccessible. Moreover, these systems are designed for large blowdown, purge, or relief events, and therefore much lower flows do not produce a perceptible AVO indication. When allowed to persist for prolonged periods of time, residual flows can become a major contributor to emissions and a loss of marketable gas.
- Flares require a reasonable degree of turbulence at the flare tip to promote good destruction efficiencies. Destruction efficiencies at low flows are much lower than those during flaring episodes under design conditions.

5.1.2.1 Leakage Into Vent or Flare Systems

Intermittent vents and flares should be checked for leakage into the collection header. Where residual flows in the header are detected, further efforts should occur to determine the exact cause of the leakage or residual flow. The cause may be leakage past the seat of a connected pressure relief valve or blowdown valve; however, a manual blowdown or purge-gas valve inadvertently may have been left partially or fully open.

Ultimately, facilities should consider installing flow meters, monitoring ports, or flow switches on intermittent vent or flare systems to allow frequent or continuous self-monitoring of leakage into vent and flare systems.

Where significant losses into the vent or flare header are difficult to avoid, facilities should consider installing a flare or vent gas recovery system.

5.1.2.2 Excessive Purge Gas Consumption

All flares should be checked to confirm that purge gas consumption rates are reasonable (that is, are sufficient to safely meet minimum requirements). Specific matters to check or consider are as follows:

- Some facilities use flash gas from amine sweetening units or glycol dehydrators as a replacement for, or supplemental source of, purge gas. This may greatly exceed the necessary requirements, and should be reviewed to consider conserving these gas streams and providing only enough purge gas to safely meet minimum requirements.
- The control system for supplying purge gas to a flare system is usually just a manual valve and possibly a regulator or a fixed orifice plate with no actual flow indication or monitoring. The tendency in these cases is to err on the side of conservatism, which potentially results in far more purge gas consumption than required. Frequently, operations personnel manually adjust the purge rate until a reasonable-sized flame is

visible at the flare tip, without any specific criterion as to size of the flame and without realizing that small changes in flame size can represent large changes in the amount of purge gas supplied.

- Many flares do not feature, and would greatly benefit from, installation of a purge reducing seal. The purge seal is a device installed near the tip of the flare stack that greatly reduces the minimum purge gas flow rate needed to prevent air from flowing down into the flare and causing burn-back, which could damage the flare tip and pose a safety issue.
- Flares equipped with an unreliable pilot or ignition system requires operations personnel to increase purge gas flows to help maintain a flame at the flare tip. While this is an easy short-term solution to the problem, it can become an extremely costly long-term solution due to excessive fuel consumption.

5.1.3 Flare Gas Enriching Systems

Flare gas may sometimes be enriched with fuel gas either to meet local regulatory requirements on the minimum-required heating value of the flare gas (that is, to ensure stable combustion) or to promote greater atmospheric dispersion of the flaring emissions (particularly SO₂) through increased thermal buoyancy. The installed flare gas enriching system is often a manual system designed in the same way as purge gas systems, and thus may evidence the same issues (see Section 5.1.2.2), for which they should be checked.

5.1.4 Low Efficiency Pilots on Continuous or Intermittent Flares

In recent years, many technological advancements in design of flare pilot systems have greatly improved their reliability, performance, and efficiency with respect to fuel requirements. Fuel consumption of existing pilots should be reviewed to determine if significant savings are possible by upgrading to a more advanced design.

5.2 Measurements

The Global Gas Flaring Reduction (GGFR) Partnership (a World Bank-lead public-private initiative) (<http://www.worldbank.org/en/programs/gasflaringreduction>) has developed a guide on flare and vent gas measurement (GGFR 2008) that should be applied (<http://documents.worldbank.org/curated/en/689451468158369316/Guidelines-on-flare-and-vent-measurement>).

5.3 Reduction Potential

Useful reference documents on reducing venting and flaring and optimizing these systems include the following:

- CAPP. 2006. *Best Management Practices for Facility Flare Reduction*. (<https://www.capp.ca/publications-and-statistics/publications/114231>).
- American Petroleum Institute (API). *Recommended Practice 521: Guide for Pressure-Relieving and Depressuring Systems*. (<https://www.api.org/>).
- API. *Recommended Practice 520: Sizing, Selection, and Installation of Pressure-Relieving Devices in Refineries*.
- API. *Recommended Practice 537: Flare Details for General Refinery and Petrochemical Service*.

Additional information is summarized in Table 9.

Table 9: EPA Natural Gas Star documents on cost-effective options for reducing CH₄ emissions from vent and flare systems

Document Title	Capital Cost (USD)	Estimated Payback	Applicable Industry Segments			
			Production	Gathering and Processing	Transmission	Distribution
Redesign Blowdown Systems and Alter ESD Practices, PRO Fact Sheet #908 (https://www.epa.gov/natural-gas-star-program/redesign-blowdown-systems-and-alter-emergency-shutdown-practices).	\$1,000 to \$10,000	0 to 1 year			✓	
Install Flares, PRO Fact Sheet #904 (https://www.epa.gov/natural-gas-star-program/install-flares).	\$10,000 to \$50,000	0 to 1 year	✓		✓	
Install Electronic Flare Ignition Devices, PRO Fact Sheet #903 (https://www.epa.gov/natural-gas-star-program/install-electronic-flare-ignition-devices).	\$1,000 to \$10,000	1 to 3 years	✓	✓	✓	✓

Also, CAPP (2006) has published a document on *Best Management Practices for Facility Flare Reduction* (<https://www.capp.ca/publications-and-statistics/publications/114231>).

6 Mitigation Opportunities to Assess: #4 Combustion Equipment

Heaters, boilers, and engines are widely used throughout the oil and gas industry. Collectively, they are the dominant source of GHG emissions because of large amounts of fuel consumption. At most facilities, natural gas, or sometimes even oil, is taken from the process and used as fuel. On an industry-wide basis, most of this fuel is used by compressor engines, pump engines, heaters, and boilers. Table 10 lists estimated disposition of this fuel by each type of device.

Other fuel uses include make-up gas to flare gas streams to satisfy minimum heating value requirements, supplemental fuel for incinerators to achieve good destruction efficiencies and to maintain minimum stack temperatures needed to achieve good atmospheric dispersion of the emitted pollutants, flare and incinerator pilot gas, and flare and vent header purge gas (see Section 5).

Table 10: Percentage distribution by primary source category of total fuel consumption within each sector in the oil and gas industry

Sector	Typical Percentage Distribution by Source Category of Total Use			
	Reciprocating Engines	Gas Turbines	Heaters/Boilers	Incinerators
Oil Production	40.0	0.0	60.0	0.0
Gas Production	68.9	3.5	27.6	0.0
Heavy Oil Production	0.0	0.0	100.0	0.0
Crude Bitumen Production	0.0	0.0	100.0	0.0
Sweet Gas Plants	84.9	0.0	15.1	0.0
Sour Gas Plants – Flaring	17.5	11.4	71.1	0.0
Sour Gas Plants – Recovery	15.6	10.2	73.4	10.9
Reprocessing Plants	0.0	85.0	15.0	0.0
Gas Transmission	5.3	94.3	0.4	0.0
Propane Consumption	40.0	0.0	60.0	0.0

Source: Colley et al. 1983. Alberta Oxides of Nitrogen Emissions Forecast: 1980-2000. A report prepared by Western Research Ltd. for Alberta Environment. Calgary, Alberta.

6.1 Recommended Checks

Two key evaluations should occur to identify cost-effective opportunities to reduce fuel consumption: (1) process optimization to minimize heat demands and engine loads, and (2) optimization of operation of each heater, boiler, engine, or incinerator. The first type of evaluation may include a review of the facility design to ensure exploitation of all reasonable opportunities for waste heat recovery and minimization of pressure drops and recycling. Performance benchmarking against rigorous process simulations or historical baselines may be performed as a global check for proper performance.

Evaluation of individual units (engines or heaters) involves conducting performance tests to confirm operation of the equipment at acceptable efficiency levels and efficient operation of the coupled pump or compressor for engines. These tests should include the following: confirmations of proper air-to-fuel ratios, good combustion, and operation of the unit on an efficient portion of its performance curve.

Facilities also should consider checks for internal process leaks that may be contributing to reprocessing of process streams, especially on reciprocating compressors. On reciprocating compressors, cylinder intake and discharge valve leakages cause some recompression of gas, resulting in higher cylinder exit temperatures that reduce compressor efficiencies.

Additionally, all heat exchangers (aerial coolers) should be checked to confirm that their performances are in accordance with design specifications and that they have not become fouled. A small change in temperature differences across the heat exchanger may significantly affect fuel or energy demands in other parts of the process.

6.2 Measurements

6.2.1 Fuel Consumption

A wide variety of fuel gas metering arrangements may be in place at facilities, which complicates production account requirements and thereby introduces a potential for errors. At many facilities, a single flow meter measures the total amount of fuel withdrawn from the process. Sometimes secondary meters are installed to determine the fuel disposition by major fuel-use category. In some cases, the available fuel gas meter or meters may measure only a portion of the fuel gas usage. For example, it is common practice to supply packaged compressor units with a dedicated fuel gas meter. A facility might rely on these meters to determine fuel use by the compressor engines, and just estimate the amount of fuel consumption by all other sources (for example, fuel for heaters, reboilers, incinerators, flare pilots, and for flare header purge and makeup gas). Fuel gas use for non-combustion purposes (for example, instrument gas, compressor start gas, dehydrator stripping gas, blow-case supply gas, and some blanket gas and equipment purging applications) may occur either upstream or downstream of available fuel gas meters, or a combination thereof. Complexities in fuel gas metering and accounting often result from additions of and changes to a facility over time.

Information on fuel disposition by type of combustion device is most important to determine emissions of criteria air contaminants, such as CO, NO_x, and PM, because emission factors for these pollutants vary greatly according to the type of combustion device (that is, reciprocating engine, turbine engine, or heater/boiler). GHG emissions are less of an issue because CO₂ is the predominant contributor to GHG emissions from fuel combustion, and emission factors for this pollutant vary little with the type of combustion device. Methane emission factors for fuel combustion do vary significantly with the type of combustion device and may contribute up to 17 percent of fuel-use GHG emissions. N₂O emissions from fuel combustion contribute much less to fuel-use GHG emissions. Moreover, N₂O emission factors currently are independent of the type of combustion device.

Composition of natural gas may vary appreciably from site to site, but variation in carbon content of the fuel is smaller—typically from 64 to 76 percent on a mass basis for different types of gas streams (for example, raw gas, processed gas, tank vapours, and dehydrator vent gas). In processed natural gas, the range of carbon content may be smaller still, only about 72 to 74 percent on a mass basis.

6.2.2 Performance Tests

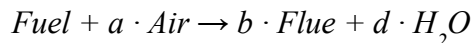
Performance testing on a combustion source involves analyzing the flue gas, measuring the flue gas temperature, determining fuel gas composition, and if possible, measuring the flow rate of one or more of the following: fuel gas, combustion air, and flue gas. Additionally, make and model of each unit, and ambient conditions (that is, temperature and barometric pressure) at the site should be recorded if available.

Typically, insufficient process data are available to allow a reliable estimate of the total amount of useful process work done by each unit or to determine overall unit performance.

Consequently, a simplified approach may be followed to evaluate the parameters listed below and to determine their departures from proper operating conditions to quantify opportunities for improvement including:

- Residual heat content of the discharged flue gas (stack losses).
- Excess air setting.
- Concentration of CO and unburned hydrocarbons in the flue gas.

Measured fuel and exhaust gas compositions should be referenced to determine the air-to-fuel and exhaust-to-fuel ratios. Species mole balances and the following combustion relation may be applied for this purpose:



where a carbon mole balance is used to determine *b*, a nitrogen balance to determine *a*, and a hydrogen balance to determine *d*. These coefficients may then be used to determine flow rates of the unknown streams from the known flow.

Combustion efficiency may be defined as the total enthalpy of reactants minus the total enthalpy of the products divided by the energy content of the fuel:

$$\text{Combustion efficiency} = \frac{\dot{m}_{Fuel} \cdot h_{Fuel}^f + \dot{m}_{Air} \cdot h_{Air}^f - \dot{m}_{Flue} \cdot h_{Flue}^f}{\dot{m}_{Fuel} \cdot LHV}$$

Where:

- \dot{m} = Molar flow rate of the stream (fuel, air, or flue gas) (kmole/h)
- h^f = Heat of formation of the stream (megajoules per kilomole [MJ/kmole])
- LHV = Lower heating value of the fuel gas stream (MJ/kmole)

For ideal operation, combustion efficiencies calculated by use of this equation are expected to be within the range of 95 to 98 percent.

While combustion efficiency is useful to indicate how much energy in the fuel is converted to heat, it does not completely describe how effectively the equipment is utilizing this energy. An energy balance on a typical reciprocating engine at full load yields the following (based on manufacturers' heat load data):

- Energy from Fuel: 100%
- Useful Work: 30 to 35%
- Jacket Water and Oil Cooler: 15 to 40%
- Radiation: 3.5 to 7.5%
- Turbocharger After Cooler: 1 to 6%
- Exhaust: 20 to 35%

Heat loads for jacket water, oil cooler, turbocharger after cooler, and radiation typically depend on design or safe operating conditions. Heat lost to the exhaust is a function of the combustion efficiency and the quantity of combustion air required for efficient operation. Useful work derives from whatever heat remains after account of all losses. Because heat losses to jacket water, oil cooler, turbocharger after cooler, and radiation are typically fixed by design, the amount of heat lost up the stack is a good indication of whether or not operation of the unit is efficient.

The situation is similar, although less complicated, for heaters/boilers and gas turbine engines. For heaters and boilers:

- Energy from Fuel: 100%
- Useful Work: 70 to 85%
- Radiation: 2 to 5%
- Exhaust: 15 to 25%

And for gas turbines:

- Energy from Fuel: 100%
- Useful Work: 30 to 40%

- Radiation: 2 to 5%
- Exhaust: 60 to 70%

Stack heat losses are calculated via a simplified heat balance:

$$\text{Fraction of Heat Loss} = \frac{\text{Stack Losses}}{\text{Heat Input}}$$

Where:

$$\text{Heat Input} = \text{Energy Content of Fuel} + \text{Sensible Heat in Fuel} + \text{Sensible Heat in Combustion Air}$$

$$\text{Stack Losses} = \text{Energy Content of the Exhaust Gas} + \text{Convective Stack Losses} + \text{Sensible Heat in the Exhaust Gas}$$

Optimum air-to-fuel ratio varies significantly among reciprocating engines according to the make and model of unit. Hence, specific manufacturers' values should be used. For heaters and boilers, 15 percent excess air may be assumed to be sufficient for proper operation.

6.2.3 Internal Process Leakage

Valve leakage in reciprocating compressors may be detected by monitoring inter-stage and discharge process gas temperatures. The amount of leakage and the resulting performance loss can be back-calculated through simulation of the compression process. Thermal imaging is another common means for detecting internal leakage problems and can often detect drain or bypass valves that are not seating properly. Ultrasonic techniques offer the greatest sensitivity for detecting leakage past valve seats.

6.3 Reduction Potential

Generally, fuel use at oil and gas facilities may be reduced via implementation of more aggressive energy auditing and conservation programs.

Relative potential for reductions in fuel use generally is lowest at large newer facilities with dedicated, full-time maintenance staff and greatest at older unmanned facilities, especially where the facility is deemed to be in the latter stages of its useful life. Recent experiences at a variety of different facilities indicate average potential reductions of 10 to 15 percent in fuel use. Notwithstanding these reductions, average specific energy intensities of oil and gas production are generally increasing with time because of increased water disposal and gas compression requirements as reservoirs are depleted and increased transportation distances as companies must search farther afield to replenish reserves.

The following are key elements for consideration as part of an energy management program at an oil and gas facility:

- Process optimizations to reduce direct energy requirements and amounts of recycling and reprocessing. For example, some sour gas processing plants are finding financially attractive opportunities to optimize fuel use by tail gas incinerators via introduction of

complex control loops to evaluate fuel requirements as a function of both process conditions and local meteorology.

- Improvement in energy efficiencies of gas-fired equipment through increased monitoring of unit performance and frequency of servicing. Most manufacturers recommend conducting minor tune-ups to adjust air-to-fuel ratios at least four times per year with each changing season. Operators should check engines at these times for possible valve or ignition problems via analysis of flue gas and conduct regular checks for gas flows from the engine crankcase. Engine crankcase vents usually are not checked as part of normal engine inspections; however blow-by past engine piston rings and engine crankcase vents can contribute significantly to energy losses.
- Where process conditions differ appreciably from initial design specifications, there may be an opportunity to replace oversized compressor and pump engines with smaller units to allow operation at more efficient points on the performance curve. For example, fuel consumption by a typical 746-kilowatt, natural gas-fueled engine is 16.7 percent lower at full load than at half load. As high as 50 percent reductions in fuel consumption are possible in extreme cases.
- Implementation at larger facilities of waste heat recovery or co-generation schemes.

7 Mitigation Opportunities to Assess: #5 Recirculating Chemical Treatment Systems

Glycol dehydrators and amine sweetening units are the most common types of re-circulating chemical treatment systems encountered at oil and gas facilities. In these systems, the circulated liquor is brought into contact with a gas stream, usually in an absorber (or contactor) column, and then separated and passed through a regeneration loop before returning to the absorber section. The regeneration loop features a reboiler, which applies heat to the liquor to reverse the absorption process.

A low-pressure flash separator is sometimes installed between the absorber and regenerator to release any solution gas that may be entrained in the rich (wet) liquor. The gas separated in the flash separator may be used to supplement the fuel and stripping gas required for the reboiler. Any excess gas is discharged through a back-pressure valve to atmosphere. The system also features a heat exchanger to preheat the rich liquor before it reaches the reboiler.

Primary causes of hydrocarbon emissions are secondary absorption/desorption by the liquor, entrainment of some gas from the absorber in the rich liquor, and possibly use of stripping gas in the reboiler. In glycol and amine systems, key secondary compounds possibly removed by the liquor are aromatic hydrocarbons (for example, benzene, toluene, ethylbenzene, and xylenes [BTEX]), which are notable toxic substances.

7.1 Recommended Checks

Key matters for consideration regarding re-circulating chemical treatment systems are as follows:

- Optimization of the unit to minimize the liquor circulation rate, and thereby reduce the load on the reboiler and emissions or secondary absorption products released in the flash gas and reboiler.
- Disposition of the flash gas, which usually may be recovered and either used as fuel or compressed back into the process inlet.
- Disposition of the off-gas from the reboiler (for glycol systems, the opportunity may be available to condense the water vapour and recover the hydrocarbon fraction; for amine systems, more efficient disposal options may be available).

7.2 Measurements

Refer to Section 6.2 for performance of the reboiler and to Section 5.2 for any related process venting or flaring. Process simulations normally occur to determine optimum operating conditions for the overall re-circulating chemical treatment process.

7.3 Reduction Potential

CAPP (2000) has developed a *Best Management Practice for Control of Benzene Emissions from Glycol Dehydration* (<https://www.capp.ca/publications-and-statistics/publications/279307>), which provides guidance on measuring and managing process emissions from these units. Specific guidance provided by the EPA Natural Gas Star Program is summarized in Table 11.

Table 11: EPA Natural Gas Star documents on cost-effective options for managing methane emissions from glycol dehydrators

Document Title	Capital Cost (USD)	Estimated Payback	Applicable Industry Segments			
			Production	Gathering and Processing	Transmission	Distribution
Reroute Glycol Skimmer Gas, PRO Fact Sheet #201 (https://www.epa.gov/natural-gas-star-program/reroute-glycol-skimmer-gas).	\$1,000 to \$10,000	0 to 1 year	✓	✓	✓	
Pipe Glycol Dehydrator to Vapor Recovery Unit, PRO Fact Sheet #203 (https://www.epa.gov/natural-gas-star-program/pipe-glycol-dehydrator-vapor-recovery-unit).	\$1,000 to \$10,000	0 to 1 year	✓	✓	✓	
Replace Glycol Dehydrator Units with Methanol Injection, PRO Fact Sheet #205 (https://www.epa.gov/natural-gas-star-program/replace-glycol-dehydration-units-methanol-injection).	\$1,000 to \$10,000	0 to 1 year	✓	✓	✓	
Portable Desiccant Dehydrators, PRO Fact Sheet #207 (https://www.epa.gov/natural-gas-star-program/portable-desiccant-dehydrators).	\$1,000 to \$10,000	0 to 1 year	✓			

Document Title	Capital Cost (USD)	Estimated Payback	Applicable Industry Segments			
			Production	Gathering and Processing	Transmission	Distribution
Eliminate Unnecessary Equipment and/or Systems, PRO Fact Sheet #504 (https://www.epa.gov/natural-gas-star-program/eliminate-unnecessary-equipment-andor-systems).	\$1,000 to \$10,000	0 to 1 year	✓	✓	✓	✓
Zero Emissions Dehydrators, PRO Fact Sheet #206 (https://www.epa.gov/natural-gas-star-program/zero-emissions-dehydrators).	\$10,000 to \$50,000	0 to 1 year	✓	✓	✓	✓
Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators, Lessons Learned (https://www.epa.gov/natural-gas-star-program/optimize-glycol-circulation-and-install-flash-tank-separators-glycol).	\$10,000 to \$50,000	0 to 1 year	✓	✓		
Convert Natural Gas–Driven Chemical Pumps, PRO Fact Sheet #202 (https://www.epa.gov/natural-gas-star-program/convert-natural-gas-driven-chemical-pumps).	\$1,000 to \$10,000	1 to 3 years	✓	✓	✓	
Convert Pneumatics to Mechanical Controls, PRO Fact Sheet #301 (https://www.epa.gov/natural-gas-star-program/convert-pneumatics-mechanical-controls).	\$1,000 to \$10,000	1 to 3 years	✓	✓	✓	✓
Replacing Gas-Assisted Glycol Pumps with Electric Pumps, Lessons Learned (https://www.epa.gov/natural-gas-star-program/replacing-gas-assisted-glycol-pumps-electric-pumps).	\$1,000 to \$10,000	1 to 3 years	✓	✓		

Document Title	Capital Cost (USD)	Estimated Payback	Applicable Industry Segments			
			Production	Gathering and Processing	Transmission	Distribution
Replacing Glycol Dehydrators with Desiccant Dehydrators, Lessons Learned (https://www.epa.gov/natural-gas-star-program/replacing-gas-assisted-glycol-pumps-electric-pumps).	\$10,000 to \$50,000	1 to 3 years	✓	✓		

The relevant CCAC (2017e) guidance is provided in *Technical Guidance Document Number 5: Glycol Dehydrators* (<https://www.ccacoalition.org/en/resources/technical-guidance-document-number-5-glycol-dehydrators>).

The following are a few process variables that may be optimized to help minimize the heating load on the reboiler, and to a lesser extent, control emissions or losses of secondary absorption products:

- Flash Tank:** If appreciable quantities of natural gas are absorbed or entrained in the liquor, a two-phase flash separator should be installed downstream of the rich/lean liquor heat exchanger. The separated gas can be used as fuel for the reboiler or as stripping gas, or, as a last resort, sent to flare for disposal. If significant amounts of hydrocarbon liquids are encountered at this point, the flash tank should be designed for three-phase separation. Otherwise, the hydrocarbon liquids could cause problems in the reboiler (that is, gradual coke accumulation on the fire tube) and lead to reduced boiler efficiency and increased combustion emissions.
- Glycol Circulation Rate:** The amount of actual gas treatment provided by recirculating chemical treatment systems is usually determined by the liquor circulation rate. However, because this rate also determines the amount of secondary absorption products emitted, it is important not to set the circulation rate any higher than needed. The usual practice is to set the circulation rate for peak flows plus a comfortable safety factor (for example, +10 percent). Thereafter, adjustments to the circulation rate with changes in throughput occur infrequently, if at all. Consequently, there is considerable potential for optimization of the liquor circulation rate—not only would this reduce venting emissions, but it would remove unnecessary load from the reboiler and thereby lower combustion emissions and conserve fuel.
- One option is to conduct periodic performance tests (for example, sample the rich and lean glycol) on each unit, and manually adjust the glycol circulation rate. Sometimes, replacement of the existing pump with a smaller pump may be necessary (the glycol pump and other components of the dehydrator commonly are oversized because of production decline or low gas demand).

- Another option is to implement a continuous feedback control loop to regulate a variable speed recirculation pump.
- **Inlet Gas Temperature and Pressure:** The amount of emissions that may occur from a well-posed application involving properly trained operators is ultimately determined by the amount of contaminant to be removed by the chemical treatment system. For glycol dehydrators, the amount of water vapour to be removed is determined by the inlet temperature and pressure of the gas. Water content of the gas will decrease through condensation as temperature is lowered and pressure is increased, so will the concentrations of higher boiling point aromatics and their corresponding emissions. Accordingly, the operating temperature should be minimized and the operating pressure maximized to the fullest extent possible. In most cases, the temperature will be easiest to adjust and this will likely offer the greatest benefits. Sometimes if pressures are relatively low, it may be feasible to install an inlet air cooler when the inlet gas temperature is too high, although if temperature gets too low, the liquor may become sufficiently viscous to impair efficient contact in the absorber.
- **Reboiler Temperature:** The operating temperature of the reboiler should be as high as possible without exceeding the maximum heat tolerance of the liquor in order to ensure maximum reconcentration of the liquor and thereby suppress the necessary re-circulation rate. Temperatures too high will lead to excessive liquor losses and possibly thermal decomposition of the liquor. On a standard unit (that is, the unit with a gas-fired reboiler), temperature is thermostatically controlled automatically. Nonetheless, the reboiler temperature should be verified occasionally by use of a test thermometer to ensure recordings of true readings. The reboiler operates best when it can maintain a uniform temperature. If temperature fluctuates excessively during operation below the design capacity, the fuel gas pressure should be reduced. If reboiler temperature cannot be raised as desired, increasing fuel gas pressure to about 200 kPa and readjusting the dampers on the air intake may be necessary.

8 Mitigation Opportunities to Assess: #6 Pneumatic Devices

In the upstream petroleum industry, where compressed air is unavailable or deemed uneconomical to use, common practice is to use natural gas as the operating medium for pneumatic instrumentation systems and gas-operated devices (for example, chemical injection pumps and compressor starters). This is usually the case at single-well oil batteries, single-unit compressor stations, well-site facilities, minor field installations, and at some small (design capacity below 0.7 million cubic meters per day [Mm^3/d]) and medium-sized (design capacity of 0.7 to 7 Mm^3/d) gas processing plants. Natural gas may also be used in specific applications where available air pressure is too low to operate a given device (for example, large valves).

8.1 Recommended Checks

Measurements should occur to quantify gas consumption rates by gas-operated devices that use natural gas as the supply medium. Experience has been that consumption rates often are significantly greater than expected under the following circumstances:

- Limited information is available on the number of consumption devices, and usually the number of devices is underestimated.
- These devices receive very little attention and have not been tuned for optimum performance. For example, supply pressures may be greater than needed, and device activity levels may be set too high.
- Some devices such as continuous bleed instrument control loops will begin to use more gas as they wear.

8.2 Measurements

Measurements of gas consumption by pneumatic devices does not routinely occur at oil and gas facilities. Regarding smaller devices, these measurements may be performed using rotameters, diaphragm meters, or Hi-Flow Samplers. Regarding larger devices such as pneumatic starter motors, reliable measurements may be difficult because of the brief duration of the event and high flow rates involved. In these cases, common practice is to refer to the manufacturer's specifications and data; however, the use of clamp-on, transit-time ultrasonic flow meters may also be appropriate.

8.3 Reduction Potential

The following options may be considered to eliminate or reduce emissions from gas-operated instrumentation systems:

- Control loop tuning.
- Low-consumption control systems.
- Use of air as the supply medium.
- Replacement with equivalent electronic systems.
- Vent gas disposal or recovery systems.

Useful guidance available from the EPA Natural Gas Star Program is summarized in Table 12.

Table 12: EPA Natural Gas Star documents on cost-effective options for managing methane emissions from pneumatic devices that use natural gas as the supply medium

Document Title	Capital Cost (USD)	Estimated Payback	Applicable Industry Segments			
			Production	Gathering and Processing	Transmission	Distribution
Convert Gas Pneumatic Controls to Instrument Air, Lessons Learned (https://www.epa.gov/natural-gas-star-program/convert-gas-pneumatic-controls-instrument-air).	>\$50,000	0 to 1 year	✓	✓	✓	✓
Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry, Lessons Learned (https://www.epa.gov/natural-gas-star-program/options-reducing-methane-emissions-pneumatic-devices-natural-gas-industry).	<\$1,000	1 to 3 years	✓	✓	✓	✓
Convert Pneumatics to Mechanical Controls, PRO Fact Sheet #301 (https://www.epa.gov/natural-gas-star-program/convert-pneumatics-mechanical-controls).	\$1,000 to \$10,000	1 to 3 years	✓	✓	✓	✓

Document Title	Capital Cost (USD)	Estimated Payback	Applicable Industry Segments			
			Production	Gathering and Processing	Transmission	Distribution
Convert Natural Gas-Driven Chemical Pumps, PRO Fact Sheet #202 (https://www.epa.gov/natural-gas-star-program/convert-natural-gas-driven-chemical-pumps).	\$1,000 to \$10,000	1 to 3 years	✓	✓	✓	
Replacing Gas-Assisted Glycol Pumps with Electric Pumps, Lessons Learned (https://www.epa.gov/natural-gas-star-program/replacing-gas-assisted-glycol-pumps-electric-pumps).	\$1,000 to \$10,000	1 to 3 years	✓	✓		

Corresponding guidance by CCAC (2017a) is provided in *Technical Guidance Document Number 1: Natural Gas-Driven Pneumatic Controller and Pumps* (<https://www.ccacoalition.org/en/resources/technical-guidance-document-number-1-natural-gas-driven-pneumatic-controllers-and-pumps>).

9 Mitigation Opportunities to Assess: #7 Well Venting

Wells may be sources of venting or flaring emissions due to:

- Completions (that is, during the flowback period following multi-stage hydraulic fracturing of horizontal wells).
- Liquids unloading events.
- Casinghead gas venting.

9.1 Recommended Checks

Flowback periods following multi-stage hydraulic fracturing events typically last one to two weeks but possibly as long as two to four weeks.

9.2 Measurements

Measurements should occur to quantify the venting rate and its rate of decline to inform technical decisions on how best to manage the various types of well venting. Normally, the amount of gas vented or flared during well completions is monitored and reported as a regulatory requirement. Measured gas volumes are much less likely to be available for liquids unloading events and casinghead gas venting.

9.3 Reduction Potential

Flowback periods following multi-stage hydraulic fracturing events typically last one to two weeks but possibly as long as two to four weeks. Any hydrocarbon liquid present during the flowback period is separated from the fracking fluids and conserved. Most jurisdictions require that the gas phase be flared rather than vented. At a development well, the gas may be separated and produced in an existing gas gathering system. This approach is commonly referred to as a green completion.

Upon completion of a gas well and its transition to the production phase of its life cycle, gas flow rate may become too low to carry any associated liquids to the surface. One operating procedure sometimes applied to address this matter is to periodically vent the well to the atmosphere to blow out the accumulated liquids from the well bore. An alternative to this practice is to implement an artificial lift system by use of one of the following options:

- Foaming agents or surfactants
- Velocity tubing.
- Plunger lift, operated manually or with smart well automation.
- Downhole pumps, which include reciprocating (beam) pumps and rotating (progressive cavity) pumps.

Technical details, costs, benefits, and limitations of these methods are discussed in the EPA Natural Gas Star document: Lessons Learned – *Options for Removing Accumulated Fluid and Improving Flow in Gas Wells* (https://www.epa.gov/sites/production/files/2016-06/documents/11_options.pdf). Additional related documents are listed in Table 13.

When conventional oil wells reach final stages of exploitation, the production casing may be opened to the atmosphere to minimize pressure in the well bore and promote maximum flow of oil to the well. When an oil well reaches this stage, it is commonly referred to as a stripper well. Good practices are to use the gas to meet any on-site fuel needs and to install a small compressor to balance into the oil flow line. If these options are not practicable, it is better to flare the casinghead gas rather than vent it. A heavy oil well may start venting casinghead gas at a much earlier stage in its life cycle and could be challenged by possible lack of access to a flow line or gas gathering system; however, the available control technologies are the same. Relevant lessons learned and fact sheets are listed in Table 13.

Table 13: EPA Natural Gas Star documents on cost-effective options for managing methane emissions from well venting

Document Title	Capital Cost (USD)	Estimated Payback	Applicable Industry Segments			
			Production	Gathering and Processing	Transmission	Distribution
Connect Casing to Vapor Recovery Unit, PRO Fact Sheet #701 (https://www.epa.gov/natural-gas-star-program/connect-casing-vapor-recovery-unit).	\$1,000 to \$10,000	0 to 1 year	✓			
Installing Plunger Lift System in Gas Wells, Lessons Learned (https://www.epa.gov/natural-gas-star-program/installing-plunger-lift-systems-gas-wells).	\$1,000 to \$10,000	0 to 1 year	✓			
Install Compressors to Capture Casinghead Gas, PRO Fact Sheet #702 (https://www.epa.gov/natural-gas-star-program/install-compressors-capture-casinghead-gas).	\$10,000 to \$50,000	0 to 1 year	✓			

Document Title	Capital Cost (USD)	Estimated Payback	Applicable Industry Segments			
			Production	Gathering and Processing	Transmission	Distribution
Reduced Emission Completions for Hydraulically Fractured Natural Gas Wells, Lessons Learned (https://www.epa.gov/natural-gas-star-program/reduced-emission-completions-hydraulically-fractured-natural-gas-wells).	>\$50,000	0 to 1 year	✓			
Options for Removing Accumulated Fluid and Improving Flow in Gas Wells, Lessons Learned (https://www.epa.gov/natural-gas-star-program/options-removing-accumulated-fluid-and-improving-flow-gas-wells).	\$10,000 to \$50,000	1 to 3 years	✓			

Relevant CCAC (2017) guidance is provided in the following documents:

- Technical Guidance Document Number 7 (CCAC 2017g): *Well Venting for Liquids Unloading* (<https://www.ccacoalition.org/en/resources/technical-guidance-document-number-7-well-venting-liquids-unloading>).
- Technical Guidance Document Number 8 (CCAC 2017h): *Well Venting/Flaring During Well Completion for Hydraulically Fractured Gas* (<https://www.ccacoalition.org/en/resources/technical-guidance-document-number-8-well-ventingflaring-during-well-completion>).
- Technical Guidance Document Number 9 (CCAC 2017i): *Casinghead Gas Venting* (<https://www.ccacoalition.org/en/resources/technical-guidance-document-number-9-casinghead-gas-venting>).

10 Summary

This document offers the following observations and key elements of advancing a project from the initial opportunity identification stage to the final implementation stage:

- Results of GHG emissions mitigation reviews in North America and internationally have indicated that reasonable opportunities to achieve cost-effective, high-impact GHG emissions reductions exist at most oil and gas facilities.
- A wholistic, yet strategic, approach to identify such opportunities is likely to be most cost-efficient and productive. This may require access to specialized measurement and testing equipment or services.
- To be exploitable by a company, an opportunity must be quantifiable, viable, competitive relative to other investment opportunities, and well aligned with the company's priority objectives.
- Prefeasibility assessments generally occur to preliminarily screen identified mitigation opportunities.
- To advance opportunities beyond the prefeasibility stage, completion of a due-diligence assessment and development of a refined business case generally are necessary. This may require performing a FEED study to identify and address site-specific constraints that may apply; determination of requirements for itemized equipment, materials, and labour to improve cost-estimating; and development of a refined business case. These activities can be costly and time consuming. Typically, anywhere from 10 to 40 percent of a project's capital costs may be incurred to reach this decision point.
- Even if the refined business case indicates that the project meets all the company's acceptance criteria, approval of the project will depend on availability of adequate financing.
- A variety of financing mechanisms exist, including self-financing, external financing, partnerships, and third-party agreements. Advantages and disadvantages of each are delineated in Section 2.4.
- A detailed engineering design, procurement and contracting, construction, commissioning, and start-up should follow management's approval and authority for the necessary expenditures. The cost of obtaining all necessary approvals is often part of the prior due diligence process and development of the refined business case.
- Upon full implementation of a project, generation of marketable emissions offsets may be possible if the project occurs within a jurisdiction where an active carbon trading program exists. Otherwise, opportunity may be available to develop marketable ITMOs. In either case, MRV requirements can be demanding and are comparable to commerce standards for other fungible commodities.

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