Flaring management—a framework for the oil and gas industry

This section is aimed at oil and gas production operators, and presents a framework for the identification and management of solutions to successfully bring flared gas to more productive use.
Flaring management—a framework for the oil and gas industry

Addressing gas flaring rests on (a) the identification of project design solutions for new assets, and flare reduction projects for existing fields that can successfully bring the gas to more productive use, and (b) the expansion of potential solutions from those attainable by individual oilfield operators to solutions that fully employ the capabilities of operators and governments working together. For an individual production operator, it begins with a commitment to address the problem and then follow through with a disciplined approach of organization, planning and implementation following the framework shown in Figure 9 and elaborated in the text that follows. This section also includes supplemental information on flaring from midstream operations (including LNG facilities), and on enhanced flaring measurements and monitoring, together with a brief look at research and development.

**HISTORICAL AND CURRENT DATA GATHERING AND ANALYSIS**

Before making operational changes or capital investments to reduce flaring, it is imperative that a firm basis for action is established using actual data and reasonable estimates to forecast gas volumes over time and fill any data gaps. The essential elements that require consideration when making projections of associated gas volumes are discussed below.

**Associated gas forecasts**

Associated gas forecasting to predict the near- and longer-term supply of associated gas from a producing area is a critical aspect of determining the potential flare mitigation solutions that are viable. Gas volume estimates over the life of a potential associated gas monetization project is required in order to appropriately scale the project, select the optimal technology solution, and evaluate the project economics.

Forecasting is often performed by reservoir modeling and simulation to predict future production profiles for wells or entire reservoirs. Another forecasting approach is decline curve analysis, which involves fitting a curve through historical production volumes, and then extrapolating the curve to predict future production. The larger the scope, the more data (e.g., production history, reservoir geology, completion designs, pressure history and other operational parameters) are required to make accurate predictions.

<table>
<thead>
<tr>
<th>Historical and current data gathering and analysis</th>
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<tr>
<td>- Associated gas forecasts</td>
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<td>- Measurement versus estimation</td>
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<tr>
<td>- Segregation of flare volumes</td>
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<table>
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<tr>
<th>Establishing company flaring and venting policy and procedure</th>
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</thead>
<tbody>
<tr>
<td>- Unconventional and shale operations</td>
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<tr>
<td>- New field developments</td>
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<td>- Early development facilities</td>
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<td>- Well test and early production first oil flaring</td>
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<tr>
<td>- Legacy flaring</td>
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<tr>
<td>- Venting at upstream oil and gas facilities</td>
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<tr>
<th>Management of routine flares</th>
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<tr>
<td>- Assessing local conditions and policies</td>
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<tr>
<td>- Reviewing associated gas forecasts</td>
</tr>
<tr>
<td>- Developing a utilization strategy</td>
</tr>
<tr>
<td>- Technology and economic assessment</td>
</tr>
<tr>
<td>- Green/climate change financing opportunities</td>
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</tbody>
</table>

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<tr>
<th>Management of non-routine flares</th>
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</thead>
<tbody>
<tr>
<td>- Raising awareness and visualization of flared gas</td>
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<tr>
<td>- Flaring management during non-routine/ upset scenarios</td>
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<tr>
<td>- Review of operational controls and processes</td>
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<tr>
<td>- Setting flaring targets at the station level</td>
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<tr>
<td>- Framework for variance and waivers</td>
</tr>
<tr>
<td>- Economic and technical risk assessment</td>
</tr>
<tr>
<td>- Root cause analysis and identification of ‘bad actors’</td>
</tr>
<tr>
<td>- Focused strategy for addressing ‘bad actors’</td>
</tr>
<tr>
<td>- Rotating equipment and sparing strategy</td>
</tr>
</tbody>
</table>
Reliable forecasts (those which contain a conservative expected value along with probabilistic upper and lower ranges) for associated gas availability over time are essential in the design, planning and ongoing management of an associated gas monetization project. Forecasting is an ongoing process rather than a one-time event, with the amount and quality of available data changing as development of the resource matures. Although the nature of the hydrocarbon resources, and whether the operation is onshore or offshore, informs the range of possible development concepts, the forecasting process evolves over the course of the development activities, as noted in Table 4.

### Measurement versus estimation

Associated gas forecasts rely on historical data on gas flows (e.g., in-field use, reinjection, sales and gas flared) for existing operations, and on production forecasts for new development activities. In order to select and design optimal solutions to avoid flaring, an accurate quantification of the gas flow to flare is required. In general, measurement of gas flared is considered more accurate than estimation approaches, although flare gas metering can present unique challenges due to the fact that a flare system is designed to handle two very different operating scenarios, i.e., large emergency releases during an upset or blowdown condition, and low flow releases during ‘normal’ operating conditions.

<table>
<thead>
<tr>
<th>PHASE</th>
<th>PURPOSE OF FORECAST</th>
<th>LIMITATIONS AND POTENTIAL ERRORS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production forecasting at the exploration stage</td>
<td>- To determine which development approach will be profitable</td>
<td>- Limited information available constrains potential forecasts</td>
</tr>
<tr>
<td></td>
<td>- Better definition of potential resources</td>
<td>- Focus on too narrow a set of development options</td>
</tr>
<tr>
<td></td>
<td>- Feasibility screening of development concepts and expected timing</td>
<td>- Underestimating capital costs and expenses</td>
</tr>
<tr>
<td></td>
<td>- To obtain approvals from authorities, partners and investors</td>
<td></td>
</tr>
<tr>
<td>Production forecasting during the appraisal phase</td>
<td></td>
<td>Only initial production flowback from appraisal wells or production history from analogue fields</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Same issues as noted above</td>
</tr>
<tr>
<td>Production forecasting during early field life</td>
<td>- To further define resources, near-term production and growth</td>
<td>Limited production history can lead to inaccurate simulations and unreliable predictions</td>
</tr>
<tr>
<td></td>
<td>- To narrow down the development options, facilities and recovery methods</td>
<td>- Pressure to satisfy partners and investors on limited performance data</td>
</tr>
<tr>
<td></td>
<td>- To obtain production allowances from governmental authorities</td>
<td>- Underestimating timing and cost, ramp-up of production, and total resources</td>
</tr>
<tr>
<td>Production forecasting during established field life</td>
<td></td>
<td>Some fields may not have reliable well test data or pressure surveillance</td>
</tr>
<tr>
<td></td>
<td>- To reassess resource potential and better define geo-model blocks/production units</td>
<td>- Underestimating total resources and the timing and cost of changes in the production concept</td>
</tr>
<tr>
<td></td>
<td>- To optimize recovery methods and facilities for maximization of economic recoveries</td>
<td>- As the field ages, there could be changes in associated gas composition (e.g., increasing H₂S), which should be considered</td>
</tr>
</tbody>
</table>
In complicated applications, including large pipe diameters, flow velocities that vary over wide ranges, variable gas composition, low pressures, and entrained liquids and solids, estimation approaches can be preferred over flare metering. Two American Petroleum Institute (API) Standards offer comprehensive information on flare design and measurement of flow to flares, respectively.

**Direct measurement of flare gas volume**

Accurate measurement of the vented and flared volumes is important when evaluating the applicability and economics of flare mitigation technologies. This section presents some of the common types of flow meters used for flare gas measurement, together with a comparison of the range, accuracy, calibration frequency and cost ranges. Supplemental material is provided in Annex II.

- **Differential pressure flow meters**
  Various types of differential pressure flow meters are available (e.g. orifice plate, V-cone, pitot tubes/annubars), all of which operate on the principle of conservation of energy, i.e. the total energy of an isolated, steady flow system must remain the same over time. When a particular aspect of the system, such as pipe diameter, is modified, another aspect of the system must change to maintain the system’s energy. Differential pressure meters utilize this principle by analysing pressure differences in the system both upstream and downstream of the flow element. While differential pressure flow meters are the most common flow measurement devices utilized in upstream oil and gas operations, they have several disadvantages that make their use for flare gas metering difficult, such as the range of operation, downstream pressure loss and straight-line pipe requirements. A chapter in the API Manual of Petroleum Measurement Standards offers more detailed information on orifice meters.

- **Ultrasonic time-of-flight flow meters**
  This type of meter determines the fluid flow rates based on flow velocity, flowing pressure, flowing temperature and composition of the gas. Ultrasonic meters operate by measuring the travel time of ultrasonic signals transmitted with, and against, the fluid flow. The difference in transmittal time of the ultrasonic signals is used to calculate the fluid velocity. Ultrasonic flow meters can be installed permanently or as portable clamp-on models. Ultrasonic devices typically have the highest turndown ratios of all flow metering devices, require infrequent calibrations and can handle varying gas compositions. For this reason, ultrasonic meters are the most common type of measurement device used for flare gas streams. Permanent installations require a long run of straight line pipe, and clamp-on models are impractical for low pressures (< 80 psig) or for use near atmospheric flares. Ultrasonic meters are among the most expensive flow metering devices.

- **Thermal mass anemometers**
  This type of meter measures the mass flow rate of a stream, either by constant power or constant temperature approaches. Thermal mass meters are capable of continuous measurement and the many available models provide for a range of potential turndown ratios all at relatively reasonable costs. Drawbacks for thermal mass meters include their inability to handle fluids with increased levels of particulates, and their lack of suitability for use in wet gas streams where water or condensing hydrocarbons would distort the measurements obtained by the sensors.

- **Coriolis flow meters**
  The operation of this type of meter is based on the principle of the ‘Coriolis effect’. Coriolis meters offer accurate results and do not have any straight-line pipe requirements. However, they have limited applicability for flare gas streams, especially for pipe sizes greater than 6 inches (15 centimeters), and are also considered expensive. A chapter in the API Manual of Petroleum Measurement Standards offers more information on Coriolis flow meters.

While each meter type has advantages and disadvantages, one of the key attributes for measuring vent and flare gas flow rates is the turndown ratio, or ability to measure accurately over a wide range of flow rates that will be encountered for most flares. Ultrasonic, thermal mass, and Coriolis meters have higher turndown ratios than differential pressure meters, but generally at higher cost. Portable external ultrasonic meters have the added advantage that they can be installed without shutting-in production, but they have a higher cost relative to other meters. Coriolis meters have a relatively high turndown ratio and do not require annual calibration, so these meters will have lower operating and maintenance costs, and the highest accuracy. API Technical Report 2571 offers comprehensive information on different equipment used in the measurement and reporting of fuel gas flow rates.
Estimating flare gas volume

In the absence of continuous metering, estimation methods are likely to be the most common approach used by upstream producers to assess flare/vent volumes. These methods utilize: gas-to-oil ratios (GORs); mass balances; process simulations; monitoring valve positions for streams routed to flare; and, more recently, remote sensing. Such methods can provide acceptable alternatives to direct flow measurements where conditions are relatively stable and the required input activity data and factors are accurately known.

Gas-to-oil ratio

Where oil production at a facility is measured but gas production is not, flared volumes can be estimated using GOR data for the wells at the facility. Corrections need to be made for any on-site uses of the gas (e.g. fuel, source gas for pneumatic devices, etc.). GOR values vary with the crude oil production rate, change according to the extent of reservoir depletion, and may become erratic at certain critical flow rates (e.g. due to slug flow conditions, reciprocating pumping actions, gas breakthrough in the reservoir, and other effects). GOR values should be developed based on 24-hour tests at normal flow rates, and should be re-evaluated whenever noteworthy changes in production or pumping rates occur. [6,7]

Mass balance

The mass balance approach is a traditional chemical engineering technique that can be used to provide an estimate of flared gas flows at a facility level or at an equipment level. [6,7] Generally, this involves identifying the difference between the measured or calculated flow rate of all input and output gas and vapor streams, minus any uses and conversions. However, unless the flare gas flow rate is large relative to the absolute errors in the other data used in the calculation, mass balance may not yield an accurate estimate. This can be a particular problem for facility-level or field-level scenarios, due to measurement challenges with input streams that have varying compositions or unsteady flow rates. In addition, production accounting systems often use vented and flared gas as a single entry to balance differences that arise from totals obtained by sales or production meters. Mass balance accuracy is typically better when estimating the volume of gas released from a blowdown or depressurization event, where the internal volume of the vessels, piping and equipment being depressurized and their initial and final pressures and temperatures are known or are measurable.

Process simulation

Process simulations can be used to develop a more granular assessment of flows (i.e. around a particular tank battery or process unit) compared to a high-level mass balance approach. With measured input and output stream flow rates, stream composition data and process temperatures and pressures, commercial process simulators are typically able to predict flared overhead streams from individual process units with accuracies of within 5–10% for most oil and gas applications. [6,7] However, these simulations do not account for undocumented cross-connections or leakage into the flare systems that may be present in the actual field installation, and generally do not provide accurate estimates of intermittent flows.

Valve position monitoring and estimation

This method of quantifying flare gas flow rates involves monitoring the position and upstream/downstream pressures of the flow across valves in streams that are routed to flare. In this case, algorithms are developed to quantify the flow across the valve at different valve opening positions and differential pressures. Monitoring of all streams routed to flare need to be performed, and the estimated flows aggregated to represent the total flow to the flare header. This is a hybrid approach that falls between direct measurement and estimation, and uncertainty is higher than with metered results.

Remote sensing

Remote sensing data have been used by a variety of agencies and scientists to generate estimates of gas flaring and venting flows. [68,69,70,71,72] This approach involves: the use of infrared imaging systems mounted on trucks, planes or drones; continuous monitoring with long-range laser systems combined with optical mirrors; and satellite imaging. A well-known effort is housed at the Colorado School of Mines (formerly at the US National Oceanic and Atmospheric Administration (NOAA)). The current data product from this group leverages raw data from the Visual-Infrared Imaging Radiometer Suite (VIIRS), an instrument developed by the US National Aeronautics and Space Administration (NASA). However, other investigators have used a variety of different remote sensing datasets that capture intensity of light at night to estimate the flaring rate at global oil and gas fields. Although satellite data have been used to provide country-level estimates of flaring rates, [73] using the resulting satellite flaring estimates for further analysis of the oil and gas industry has proven challenging.
Further work is aimed at developing better correlations with satellite data and field-level data reported by production operators to government agencies.\[74\]

**Segregation of flare volumes**

Flare and vent systems exist in all segments of the oil and gas industry, and are used for the disposal of intermittent and continuous waste gas streams. Some common examples of flaring are provided in this section as well as the distinction between sweet and sour gas composition.

**Routine versus non-routine flaring**

The determination of the cause of a flaring event is important for enabling the identification and evaluation of flaring reduction alternatives, e.g. modification projects to reduce continuous or planned non-continuous production flaring, or to provide clear procedures to avoid future unplanned non-continuous flaring events.

Previously, Table 1 described high-level reasons why gas is flared, and Table 2 introduced the flaring categories defined by the GGFR which provide a consistent framework for analysis and communication. The examples of flaring in Table 5 are illustrative of other incidences of flaring that can potentially occur, which are worthy of inclusion with regard to minimization and elimination.

Routine flaring of associated gas represents the most significant source of GHG emissions from flaring at upstream production operations. Controlling this source of flaring is challenging and often requires major capital investments in new equipment and/or infrastructure to manage, process or export the gas, as well as viable markets to monetize the gas.

Non-routine flaring is typically intermittent and of short duration, and can be either planned or unplanned. Good governance practice would include a documented justification for any non-routine flaring event, to enable analyses of root causes and identify mitigation options for such flaring. However, regardless of the cause or classification, the ultimate goal is to pursue gas capture solutions and operating regimes that eliminate the need for any type of flaring.

**Atmospheric pressure flares versus low- and high-pressure flares**

Generally, the gas streams that make the best candidates for a gas monetization project are those which are at high pressure. Low-pressure and atmospheric-pressure gas streams can be monetized, but it is likely that compression (and treatment to remove contaminants) would be required. A multitude of factors need to be evaluated when determining which gas streams to pursue in terms of eliminating flaring. Table 6 on page 36 provides some general characteristics for atmospheric-pressure flares, low-pressure flares and high-pressure flares, and the scenarios where they are used. More information on pressure-relieving and flare systems can be found in three API Standards covering selection, sizing and installation.\[75,76,77\]

**Sour versus sweet flares**

Reservoir conditions determine whether H_2S is present in crude oil and the associated gas.\[78\] Although H_2S may originate from geochemical or biogenic sources, it has generally been thought that H_2S concentrations will increase over time due to increased microbial activity, especially if water flooding has been employed.

Designing mitigation options to address the flaring of sour associated gas requires consideration of the corrosive nature of sour gas. Additionally, safety management systems must be in place to prevent accidental releases of uncombusted sour gas, which could expose workers to dangerous level of H_2S.

For those reasons, monetizing sour gas streams in lieu of flaring typically requires that H_2S removal be one of the first gas conditioning steps prior to any end use scenario. There are many options\[79,80\] for H_2S removal, but the most common method is the use of an amine-based solvent.

---

7 Piping and equipment for sour gas streams containing H_2S (and CO_2, which is often a common ‘acid gas’ co-contaminant) must be specified with more expensive corrosive-resistant materials than that needed for sweet gas streams.
Table 5  Common flaring situations

<table>
<thead>
<tr>
<th>CLASS</th>
<th>DESCRIPTION</th>
</tr>
</thead>
<tbody>
<tr>
<td>Planned continuous flaring</td>
<td>• At existing wells — where gas production exceeds existing gas infrastructure (take-away pipeline or gas processing) capacity.</td>
</tr>
<tr>
<td></td>
<td>• At new wells — where there is insufficient infrastructure and facilities to utilize it on-site or send it to a market, or where the geology does not accommodate gas reinjection.</td>
</tr>
<tr>
<td></td>
<td>• Associated gas volume is very low (e.g. a low-GOR well) or where a well location is remote, making it uneconomical to route the gas to market.</td>
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<tr>
<td></td>
<td>• Initial design of a gas system or plant did not consider that the gas pressure was so low that a compressor was needed.</td>
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<tr>
<td></td>
<td>• Flaring of gas from process units, tanks or equipment (e.g. glycol flash drum, glycol gas stripping, acid gas from gas sweetening units, compressor seals, storage tanks, produced water handling facilities, natural gas pneumatic controllers, etc.).</td>
</tr>
<tr>
<td></td>
<td>• Continuous purge gas is added to the flare header system or to maintain the flare pilot.</td>
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<tr>
<td></td>
<td>• Gas is added to increase the heat content of low-Btu flared gas, or to maintain the combustion efficiency of flared gas containing high concentrations of inert components (e.g. CO₂, H₂S) or hard-to-combust organic compounds.</td>
</tr>
<tr>
<td>Unplanned continuous flaring</td>
<td>• Third-party gas off-taker declares indefinite force majeure due to capacity limitations resulting from mechanical failures, bankruptcy or other causes.</td>
</tr>
<tr>
<td></td>
<td>• Follows the failure of major equipment that handles gas during normal operations, where timely repair or replacement cannot be made.</td>
</tr>
<tr>
<td>Planned intermittent or short-duration flaring</td>
<td>• At new wells — where infrastructure and facilities are not present to utilize the gas on-site, send it to a market or reinject it, but where such facilities can be brought online expeditiously.</td>
</tr>
<tr>
<td></td>
<td>• Exploration-, appraisal- or production-well testing or clean-up following drilling or completions, where no gas handling equipment is on-site or before gas compressors are commissioned.</td>
</tr>
<tr>
<td></td>
<td>• Preventive maintenance (on compressors, drivers, etc.), replacement of equipment or regulatory inspections requires shutdown of the gas handling system.</td>
</tr>
<tr>
<td></td>
<td>• Preparation of a new plant (e.g. gas handling/control/instrumentation system checks) or the required shutdown of the gas handling system for work on existing field facilities or plant systems, tie-ins of new facilities, or phase-in of new operating conditions.</td>
</tr>
<tr>
<td></td>
<td>• Reservoir studies, gas injector well maintenance, or offloading of sensitive wells (where there are no facilities to recover low-pressure well-head gas).</td>
</tr>
<tr>
<td></td>
<td>• Safety-related activities (including leak testing and emergency shutdown system testing) at wells, field facilities, plants or pipelines.</td>
</tr>
<tr>
<td></td>
<td>• Production well clean-up, or immediately following workovers and recompletion activities, where the gas handling equipment on-site is not designed for temporary high-volume flows.</td>
</tr>
<tr>
<td>Unplanned intermittent or short-duration flaring</td>
<td>• Issues related to production dynamics, including start-up after facility or equipment shutdowns, off-specification gas issues, flow assurance problems (slugs, etc.), changes in hydrocarbon composition or flow, etc.</td>
</tr>
<tr>
<td></td>
<td>• Mechanical equipment failure (e.g. pumps, compressors, turbines, etc.), loss of piping integrity, or electrical system failures.</td>
</tr>
<tr>
<td></td>
<td>• Failure of automated control systems, safety systems or equipment protection instruments, or failures due to human factors (e.g. lack of preparation and procedures, non-compliance with an existing procedure, etc.).</td>
</tr>
<tr>
<td></td>
<td>• Failure of a gas-injector well, or difficulties restarting a producer well.</td>
</tr>
<tr>
<td></td>
<td>• Temporary unavailability of gas-receiving facilities.</td>
</tr>
<tr>
<td></td>
<td>• Emergency shutdown with depressurization.</td>
</tr>
<tr>
<td></td>
<td>• Activities related to start-up following emergency shutdown, including purging lines with natural gas.</td>
</tr>
</tbody>
</table>
## Flaring management—a framework for the oil and gas industry

### Table 6 Flare type characteristics

<table>
<thead>
<tr>
<th>FLARE TYPE</th>
<th>ADVANTAGES</th>
<th>DISADVANTAGES</th>
<th>APPLICATION</th>
</tr>
</thead>
<tbody>
<tr>
<td>Atmospheric flares, non-assisted</td>
<td>• Reliable operation at both full load and partial load is possible</td>
<td>• Smokeless flaring of low-pressure gas is significantly more difficult than smokeless flaring of high-pressure gas</td>
<td>• Upstream oil and gas sector</td>
</tr>
<tr>
<td></td>
<td>• Low investment and operational costs</td>
<td>• Flash gas coming off a low-pressure separator — typically has higher molecular weight requiring more air for complete combustion</td>
<td>• LNG terminals and natural gas compression stations</td>
</tr>
<tr>
<td></td>
<td>• Low maintenance costs with the use of high grade alloys, and robust design</td>
<td>• If low-pressure gas is allowed to burn without sufficient outside air or steam, the flare is likely to smoke excessively</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Reliable and stable flaring in a wide range of operating conditions</td>
<td>• The flame may impinge on the flare tip, causing damage</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Large turn-down ratio</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Air-assisted low-pressure flares</td>
<td>• Smokeless operation under a wide range of operating conditions</td>
<td>• Generally not economical when the gas volume is large</td>
<td>• Upstream oil and gas sector</td>
</tr>
<tr>
<td></td>
<td>• Smokeless flaring of high molecular weight gases is possible</td>
<td>• Higher cost than atmospheric flare</td>
<td>• Tank farms and terminals</td>
</tr>
<tr>
<td></td>
<td>• Air cooling of the flare tip, resulting in longer lifetime and lower operation and maintenance costs</td>
<td>• More complex and requires more maintenance than atmospheric flare</td>
<td>• Pipeline transport</td>
</tr>
<tr>
<td></td>
<td>• Reduced radiant heat for a given capacity</td>
<td></td>
<td>• LNG and natural gas terminals and compressor stations</td>
</tr>
<tr>
<td>Steam-assisted low-pressure flares</td>
<td>• Smokeless operation under a wide range of operating conditions</td>
<td>• Requires steam source</td>
<td>• Midstream and downstream oil and gas sector</td>
</tr>
<tr>
<td></td>
<td>• Smokeless flaring of high molecular weight gases is possible</td>
<td>• Not suitable for remote field locations</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Long tip lifetime due to steam cooling resulting in lower operation and maintenance costs</td>
<td>• Higher cost than atmospheric and air-assist flare</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Reduced radiant heat for a given capacity</td>
<td>• System is more complex and requires more maintenance than atmospheric flare</td>
<td></td>
</tr>
<tr>
<td>High-pressure flares</td>
<td>• Smokeless operation at low heat radiation</td>
<td>• Generally limited to gas streams that have a low heat content, burn readily, and require less air for complete combustion without producing smoke</td>
<td>• Upstream oil and gas sector</td>
</tr>
<tr>
<td></td>
<td>• Lower flare stack heights</td>
<td></td>
<td>• Pipeline transport</td>
</tr>
<tr>
<td></td>
<td>• No need for any assist medium</td>
<td></td>
<td>• LNG and natural gas terminals and compressor stations</td>
</tr>
<tr>
<td></td>
<td>• Suitable for smokeless combustion of waste gas with entrained liquids</td>
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<td></td>
</tr>
<tr>
<td></td>
<td>• Possible to integrate a low-pressure flare with a high-pressure flare in a single flare tip</td>
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<td></td>
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</tbody>
</table>
Gas treatment can occur close to the well head — where the associated gas streams from several wells are combined and then sent through a modular gas sweetening unit — or at a large gas plant treating significant quantities of gas. In either case, an amine-based solvent in the sweetening unit absorbs H₂S and CO₂ in a packed tower contactor. The H₂S-rich solvent is regenerated by driving off the acid gases (H₂S and CO₂) and the lean solvent is recycled back to the absorption tower. If there is sufficient quantity, such as at a gas plant, the high-H₂S stream from the regeneration step can be converted to elemental sulfur recovery. For smaller-scale operations at field processing facilities, an alternative to elemental sulfur recovery is the injection of the acid-rich gas stream into a suitable, authorized underground zone.

Section 2
Flaring management—a framework for the oil and gas industry

ESTABLISHING COMPANY FLARING AND VENTING POLICY AND PROCEDURES

This section provides a description of the various scenarios where associated gas flaring occurs, and the approaches that can prove helpful in reducing volumes flared.

Unconventional and shale operations

Unconventional hydrocarbon resources are those that are accessed via a variety of extraction techniques other than via traditional vertical wells. They include heavy oil, oil sands, tight oil, oil shale, shale gas, coal bed methane, and tight gas. Of these, the most significant growth in recent history has been in tight oil and gas production (sometimes referred to as shale oil and gas) due to the use of horizontal drilling and hydraulic fracturing, as shown in Figure 10.

Figure 10 Horizontal wells in the US

Notes: Vertical well production also includes wells created by directional drilling and by unknown drilling type. Tight oil volumes include liquid production from shale gas formations, and shale gas totals include natural gas volumes from the tight oil formations.

Figure 11 Trend in quarterly flaring in the Permian Basin (November 2019 estimate)

Tight oil development has surged since 2010 in the Permian Basin and the Bakken region in the US. Along with this, the production of substantial volumes of associated gas and a corresponding increase in flaring have attracted significant attention. One perspective on the amount of gas flared in the Permian Basin is that, based on the flare rates in the third quarter of 2019, if all flared or vented gas was captured and liquefied, it could fill a Q-Max LNG carrier (the world’s largest carrier size) every 10 days.

Figure 11 shows the upward trend in the quarterly volumes of natural gas flared in the Permian Basin.
Challenges faced when addressing flaring in unconventional operations

Several factors contribute to the growth in associated gas production from tight oil plays:

- In tight oil formations, such as in the Bakken region in Central North America, it is not unusual for the GOR (the ratio of natural gas to crude oil production) to gradually increase as wells mature. However, once pressure in the formation (or perhaps in a more localized section of the reservoir) reaches the bubble point — where natural gas dissolved in crude separates naturally — gas production can begin to increase. Figure 12 illustrates this trend in increasing GOR in the Bakken region over time.

- Unconventional wells characteristically have a high initial production and steep decline curve. Consequently, to grow production from a field (or even just maintain production levels), new wells must be drilled and completed at a rate beyond that required in conventional fields; production growth therefore requires an ongoing, high level of drilling activity.

- It is a challenge for production operators and midstream entities to match equipment design with the high initial production and steep decline profiles for operating areas. The building of additional infrastructure to gather, process and transport associated gas and related liquids products often lags the growth in production of gas volumes. A major reason cited for this disconnect is different planning and development horizons for production and midstream infrastructure. While it can take only 6 months to bring a well online, gas processing plants have lead times of 18–36 months (depending on the complexity of unit operations included), and it can take years to bring pipelines online, primarily to secure rights-of-way and complete government permitting processes. These downstream delays can be exacerbated if there is a contemporaneous erosion of natural gas prices as supply additions outpace demand growth, which can negatively affect returns on capital expenditures. Furthermore, midstream infrastructure investments are typically made with a 15-year economic horizon, while tight oil payback horizons can be in the 2–4 year range. The short-cycle wells make tight oil development highly cyclical depending on oil prices. Producers may be hesitant to take the risk of making long-term commitments to minimum gas processing and transmission volumes because it will force capital outlays to grow production when oil prices are low.

Box 2 Production decline in conventional vs unconventional operations

The Permian Basin provides a comparison between unconventional and conventional production decline. At the start of 2010, IHS Markit noted that production for the Permian Basin was approximately 880,000 barrels per day, with virtually all production coming from conventional operations. By the end of 2010, that group of wells produced 767,000 barrels per day—a decline of 110,000 barrels per day, or 14% of the production volume at the start of the year.

In 2019 most wells drilled in the Permian Basin were shale wells (hydraulically fractured), which decline much faster. At the start of the year, production stood at 3.8 million barrels per day, a million barrels per day higher than the year before. By the end of 2019, IHS Markit expected base production to decline by approximately 1.5 million barrels of oil per day—a 40% base decline rate.

These two cases illustrate the challenge in relying on past practice to predict future performance, especially as new technology is applied and competitive pressures shift.
A possible issue is that tight oil development has attracted short-term investors. Private equity funded exploration and production (E&P) companies are designed to be sold once reserves are booked. Such companies have less incentive for investing in gas infrastructure, particularly when gas flaring is an option. The impact of this phenomenon is illustrated in Figure 13 but may be temporary as the industry consolidates and short-term financial investors exit.\[94\]

Figure 13 North Dakota gas capture rates and goals \[95, 96\]

In 2014, the North Dakota Industrial Commission (NDIC) Order No. 24665 established a drilling permit policy that requires producers to submit a gas capture plan with every drilling permit application. Gas capture goals were also set. As shown in Figure 13, the state natural gas capture rate fell below target for a period of time, primarily due to insufficient natural gas processing capacity and lack of pipeline infrastructure, but has since recovered.

Certain process steps and constraints unique to tight oil operations also contribute to the amount of gas flared:
- Flowback following hydraulic fracturing generates a mixed stream consisting of crude oil, completion fluid and produced water, solid particulates such as sand, and gas. Solids prevent the flowback stream from being processed through normal production facilities. Instead, the stream is sent through special temporary facilities for a period ranging from many days to weeks, to remove the solids and separate crude oil, water and gas, which is flared.
- Once a well is in production, failure of a level control device in a field gravity separator can allow all the liquid to drain from the unit and enable gas to flow unrestricted to a storage tank meant for liquids. Since the gas flow would overwhelm the system and could create a safety concern, automatic devices send the gas to a safety flare system. Failures of pump, flow rate and compressor controllers can also lead to similar safety concerns, hence the systems are designed to incorporate automatic relief valves which send gas to flares, or to a vent in the case of a sudden high-volume, high-pressure flow.
- Many planned maintenance activities can be performed without disrupting gas flows. However, for certain components in the production process the only option is to curtail production or send gas to a flare. Curtailing production carries the risk of damaging the wells and/or the pump system in the wells, thereby potentially delaying the recovery of the wells. Unplanned maintenance is often more challenging. If a component in a facility fails but does not cause a fail-safe device to trip, it may take time to obtain replacement parts and schedule repair crews. In such cases, flaring a small portion of the produced gas for a short time may be the best decision for all stakeholders even if the exact time frame for the repair is uncertain.\[97\]

- Water and natural gas liquids that condense in gas gathering systems can restrict capacity and create a safety hazard. Removal of these liquids is performed by sending a plunger-like device called a ‘pig’ through the pipeline to push the liquids and any solids out. Some ‘pigging’ operations cause a small amount of gas to be sent to a safety flare at the pig receiving location, but in some cases the accumulation can be unexpectedly large. When this occurs, safety flaring can cascade throughout the system, even at production facilities further upstream of the receiving site.\[97\]
Commenters on a rule\textsuperscript{[98]} proposed by the U.S. Bureau of Land Management noted many other obstacles that preclude immediate connectivity of new wells to gas infrastructure, some of which are summarized below:

- A natural gas gathering line/system must be permitted, installed and operational.
- A contractual right to flow into the gas gathering system must be agreed with the company that owns the gathering line.
- Necessary permits and rights-of-way must be obtained for the pipeline from the well site to the natural gas gathering system.
- The natural gas must meet the specifications of the natural gas gathering line.
- There must be adequate reservoir pressure to allow the gas to flow into the natural gas gathering line to clean up the well and not choke it.
- The natural gas gathering line must be operational at the time of the completion.
- A gas gathering system with sufficient capacity must be in place.
- Incomplete data on gas composition limits the ability to design the production equipment or pipeline before starting operations.
- The surface rights must be obtained for installing production equipment.

In the US, and potentially in other locations, mineral leases contain expiration clauses tied to specific milestones to encourage the development of a leasehold in a timely fashion. One typical milestone is the performance of a well completion by a specified date. If the date is missed, the lease expires, causing the mineral rights owner to lose the cost of the lease as well as the investment in assessing the lease and preparing to drill it. It is common for operators in a low-price natural gas environment to drill and complete a well prior to acquiring surface equipment or contracting for gathering system space. Delays due to the lack of available reduced emissions completion (REC) equipment create an additional risk that the operator could fail to complete certain steps specified in the contract; this could negate the contract and cause the operator to lose their rights to the minerals.

\textbf{Addressing flaring in unconventional operations}

Thoughtful planning prior to the start of operations can produce significant flare reduction benefits. The API has developed a comprehensive document\textsuperscript{[99]} to guide the assessment and mitigation of potential environmental impacts in exploration and production operations, including those where hydraulic fracturing will be used. Some of the solutions that have been implemented by operators to address flaring are described below. Each of these should be considered in a company policy that addresses flaring from tight oil operations.

- **Vapor recovery units (VRUs)**
  VRUs are used on the majority of production facilities at leading companies, with some installing multiple units on tank batteries (regardless of the economics of recovered gas) to ensure 99+\% capture efficiency. Some companies have chosen to make VRU capacities the limiting factor for new facility design — using measurements from several facilities to create a conservative benchmark for the amount of gas to be recovered per barrel of oil produced.\textsuperscript{[100]}

- **Scalable leased equipment for flare gas monetization**
  A number of well service providers are offering equipment leasing options to address gas flaring at the well head or production area scale using portable, skid-mounted solutions, as described in Section 1. These include options such as flare gas to CNG and flare gas to data centers. The ability to scale using modular equipment to follow capacity declines (or increases) makes these leased equipment options attractive for addressing the most challenging flare gas utilization applications.

- **Pre-planning for take-away**
  To ensure that adequate take-away infrastructure is in place before bringing a well online, it is advisable to consider capacity as a manageable constraint that is factored into the well/field development plan. Just as time is required to overcome the constraint of securing a government agency well permit prior to drilling, so too is time required in the schedule for planning, communication and coordination to organize gas take-away capacity with midstream partners.\textsuperscript{[101]} Some companies opt to own and operate proprietary gathering and compression systems to provide a higher level of control and ensure take-away.
Up-front capacity agreements
The NDIC issued an order in 2019 to encourage ‘firm’ service contractual agreements (essentially, a capacity guarantee) along natural gas gathering pipelines thus reducing the probability of well shut-ins and flaring.[102] Such contracts may provide a greater level of certainty to producers and encourage faster investment in gathering line infrastructure because economic risk is shared between natural gas producers and midstream companies.

Operational upset resiliency
Proactively increasing reliability within the operational supply chain can mitigate the duration and volume of gas flaring caused by an operational upset. Once an unplanned event occurs, practicing just-in-time planning and implementing escalation processes to ensure that decisions are made by an individual with appropriate authority and sufficient resources will be of considerable benefit. Timely actions to sanction overtime, expedite parts, move crews around and obtain temporary equipment such as rental compressors, can make a significant difference in reducing flared volumes prior to shutting in production, if necessary.[103]

Monitoring and control capability
Leading companies include emissions monitors and gas controls as non-discretionary elements in new facility designs. These tools facilitate real-time, automatic tracking of changes in operating pressure and flared volumes at the facility, route and foreman levels.[103] When considered during the initial facility design process, these types of monitors and controls are relatively inexpensive to install and integrate with supervisory control and data acquisition systems.

New field developments
For new oilfield development projects, the consideration of associated gas capture and monetization alternatives should be among the highest-priority tasks carried out at the earliest stages of planning. Since market, governmental and commercial aspects can present hurdles to associated gas projects, the planning cycle is often longer and more complex than for the crude oil production portion of the project. However, since there is wide latitude at the inception of a new oilfield development project, each of the options for gas utilization described in the section on Flare gas-to-market options and principles (page 19) should, along with newer technologies, receive a preliminary assessment.

A model approach for company policy should consider the following elements:
- The company should establish a goal of avoiding all planned routine flaring of gas, whether continuous or intermittent, even if such flaring is allowed by government regulations or agency-issued authorizations and permits. The only flaring capacity that would be designed into the system is that which is necessary for emergencies or disposal of gas that, due to its composition, is otherwise unusable.
- For new facilities, flare systems should be designed to handle high-pressure sources to recover gas during normal operation. Recovery of gas from flare systems handling low-pressure systems during normal operations should be considered.
- The development plan should include adequate take-away capacity, including contingent capacity—which may include shared capacity with other operators—for excess flows due to planned outages and maintenance activities, from the start of drilling operations. This approach would drive holistic decision-making across an entire field over its planned economic life, generating efficiencies in planning, investment and permitting activities, and increasing stakeholder transparency.
Expenditures for gas production, gathering and installation: Where gas monetization options are not viable, coordination: Expenditures for gas production, gathering and installation: Where gas monetization options are not viable, coordination: Philosophy: The development stage takes place aft after successfully completing the appraisal period and before the beginning of the field production. Work follows the development plan, which sets out the strategy and sequence of activities required to optimally develop a field. Well placement and design, including completions (including hydraulic fracturing), are key to maximizing the recovery of hydrocarbons. For onshore operations, production facilities such as gathering lines, field separators, processing units and tankage are added to process recovered oil and gas. Offshore, many of the structures are sized, built and placed ahead of development drilling.

Commissioning of all equipment, field production facilities, gathering systems and processing plants is necessary to ensure safe and reliable operation. This includes testing of power systems, pipelines, tank integrity and, for offshore production platforms, the subsea lines as well as the onshore receiving facilities. Depending on the size of the facilities, many individual tests are needed to confirm operability. The gas used in testing and commissioning the gas handling components and systems is typically flared, but this involves a minor volume of gas compared to the life-cycle throughput. Traditionally, the focus of early development has been to have systems ready to bring oil production online and to a sales point as quickly as possible. However, gas gathering, compression, processing and take-away should all be considered at the same time as the oil facilities are installed.

A model approach for company policy covering commissioning might include the following elements:

- Philosophy: Gas flaring and venting during commissioning should be kept to the lowest level that is consistent with the safe and efficient commissioning of oil- and gas-related plant.
- Installation: All gas handling system processes (gathering, field separation and compression, central processing plant, product take-away) should be constructed, tested, commissioned and able to receive gas before the first flow of oil. Facilitating smooth acceptance testing begins at the project design phase when critical equipment, systems, instrumentation (including flare gas flow meters) and controls are evaluated and specified. To minimize flaring, preference is given to assets that have high operational reliability over those with lower initial cost. All equipment that can cause or contribute to gas flaring (e.g. pressure relief and blowdown valves) should be pre-tested and certified to operate as specified. Verification with the suppliers is managed by the project design and construction teams.
- Coordination: As soon as possible after the first flow of oil, all gas should be routed through the gas handling system. Temporary flares should be employed during the drilling and completion phase to avoid venting. The duration of flaring should be limited to the degree possible (e.g. between one and three months), and a maximum limit placed on the quantity of gas flared. A plan for reducing initial start-up flaring should be developed and communicated; this should outline a clear commissioning schedule, identify acceptable flaring activities during equipment testing and commissioning, and provide details of mitigation measures that should be used to minimize the amount of gas flared. Measures include:
  - the establishment of commissioning procedures and a permit to work system which have been developed and reviewed by the commissioning and operations teams for safety and efficiency, and which address simultaneous operations;
• initial stage commissioning should involve pressure and leak testing of the installed systems using a non-hydrocarbon source (e.g. water, air or inert gas);
• prior to the introduction of hydrocarbon, all gas systems should be purged to remove oxygen;
• if the power generation system operates on field gas, the system should be tested with fuel-gas from an alternate supply;
• prior to start-up, high-pressure tests of valves connected to the flare system should be carried out to check for operability and leakage; and
• all control valves should be replaced with spool pieces during flushing and leak testing to prevent damage by entrained solids that could compromise operability and lead to unnecessary safety flaring after start-up.

Well test and early production (first oil) flaring

During the testing of oil and gas wells, the flow rates of fluids, pressure and other characteristics of the underground reservoir are assessed. Once an oil well has been drilled, completion activities connect the formation to the well so that oil and gas can flow to the surface. For some wells where hydraulic fracturing has been used, the initial fluids produced from the wellbore flowback should be processed to separate the liquid, solid and gas phases. Volumes of oil, natural gas and water are measured to characterize the well’s performance (well testing). Liquids from well tests are typically stored in tanks at the well site. Historically, produced gas was vented or sent to a flare.[104] The information gathered determines the economic value of the well and the types of production facilities that need to be installed, including the requirements for processing facilities, infrastructure (e.g. pipelines), the number and placement of production wells and well sites to optimize resource extraction, and potential areas of future development of the field.

A model approach for company strategy covering commissioning could consider the following elements:

- The duration of the well testing operation should be minimized to limit the amount of gas that needs to be handled. Alternatively, if longer-term tests are considered essential, technologies such as mobile mini-LNG equipment should be used to collect and utilize the produced gas. Fortunately, many operators have been able to reduce the time taken to perform well tests, largely due to better test equipment and more sophisticated data analytics tools.

- For wells where hydraulic fracturing will be used, a ‘green completion’ or REC should be considered where temporary separators and other portable equipment are used to capture the gas and route it to a sales line.[105,106] For all operations, in particular for those offshore, safety is the overriding concern at all times, and especially for dynamic environments such as well testing where fluid volumes and compositions can change unexpectedly.[107,108] However, deviation from conservative approaches such as RECs are possible[109] and, if deemed necessary, should be employed only where it is possible to do so safely.

Legacy flaring

Earlier sections of this document describe the nature of routine flaring of associated gas at legacy (existing) oilfields. A pragmatic approach to identify opportunities that can address such issues was developed by IPIECA, IOGP and the GGFR.[110] It employs a structured process to prioritize opportunities and support decision making to reduce flaring and develop gas utilization projects. Additional details on how to identify, screen, prioritize and choose projects can be found in the section on Management of routine flares on page 45 of the current document. To embark efficiently on a company-wide flaring reduction effort, top-level commitment and a supportive policy are typically necessary to align production, engineering, finance and other teams involved. A model approach for company policy covering commissioning could consider the following elements:

- A clear commitment to reduce or eliminate all routine flaring should be established, e.g. the adoption of a recognized program like the World Bank ‘Zero Routine Flaring by 2030’ initiative:
  - Institutionalize the program with leadership commitment. Additional support in the form of a public goal statement or endorsement of the ‘Zero Routine Flaring by 2030’ initiative will eliminate ambiguity within the organization.
  - Articulate the aspiration, its boundaries and key parameters in a policy or other commonly accepted management document.
  - Establish goals and metrics to drive progress across the company and at all levels where operating responsibilities exist. These would include targets linked to compensation.
A structured plan should be developed to facilitate implementation and focus attention. Later sections of this guidance document offer suggestions on project identification and approaches to prioritizing source reduction/elimination opportunities, screening technology options, developing use case alternatives and driving decision-making. Such topics should be included in the structured plan.

Economics can present a significant hurdle for legacy flaring reduction projects, even when a good technological solution exists. Considering unconventional approaches to financing flaring reduction projects can help to overcome the ‘it does not meet our internal rate of return’ inertia and reduce the amount of capital that must be funded by the company.

Implementing projects is a core competency for most oil and gas operators; this competency is completely transferable to the execution of projects where associated gas can be used to satisfy in-field needs. For other projects, the solutions may require non-traditional partnerships (e.g. gas to power) or proprietary technology (e.g. mini-LNG), or may involve an extended web of government ministries, financing entities, and local and regional stakeholders. In such cases the top level commitment to the goal of reduced flaring can help internal constituencies to recognize the imperative to make projects happen.

Another key element is active monitoring of progress. This requires that robust flare gas accounting systems are deployed and maintained. Monitoring should begin with a consistent baseline of all flaring points, with volumes reported as routine flaring, non-routine flaring and safety flaring, as applicable. Accuracy can be improved with periodic (at least annual) updates. Goals and metrics should be tied to real data, with less reliance on estimates, especially as progress is disclosed publicly.

A process should be established to allow questions to be raised, and to encourage all involved parties to work towards a common understanding of definitions and boundaries, to align understanding, eliminate conflicts and build support for the goals. Consideration should be given to the flaring categories defined in Table 2 (page 15) and the examples provided in the section on Segregation of flare volumes (page 34) to help build a company-specific rulebook. An example ‘zero routine flaring checklist’ is provided in Annex III of this document.

### Venting at upstream oil and gas facilities

Venting of associated gas is the controlled release of gases into the atmosphere in the course of oil and gas production operations, typically during upset or maintenance conditions, from unintentionally unlit flares or from other sources. Examples include:

- crude, condensate, or water storage tanks operating without vapor recovery systems, especially where tank flashing losses occur;
- venting of natural gas diverted from oil and gas compression or processing equipment due to a system upset or emergency conditions, or equipment/pipeline blowdowns for maintenance;
- routine emissions from natural gas-driven pneumatic controllers and pumps;
- venting from compressor seals (both reciprocating and centrifugal compressors);
- routine emissions from glycol dehydrator regenerator and flash tanks, and amine natural gas sweetening units; and
- routine well venting during drilling and completions, workovers or liquids unloading activities.

Because venting results in higher emissions of methane than flaring, and therefore significantly higher GHG emissions, controlling methane emissions has been a focus for some time. Companies have made voluntary commitments (e.g. Methane Guiding Principles, Climate and Clean Air Coalition (CCAC) Oil & Gas Methane Partnership (OGMP), among others), industry associations have established challenging programs, and regulators have developed reporting programs and imposed specific operating practices. Many resources are available in the public domain to address methane emissions, including the Natural Gas STAR Program database maintained by the United States Environmental Protection Agency (US EPA).
The largest sources of venting, such as uncontrolled flashing from storage tanks, can be addressed by the same solutions that have been discussed for associated gas flares. Even flaring is a preferred option over venting from a GHG emissions standpoint.

**MANAGEMENT OF ROUTINE FLARES**

The GGFR’s research has shown that the overwhelming majority of flared gas (and thus the largest contribution to GHG emissions from flaring) results from the continuous flaring of large amounts of associated gas as part of the regular operations of an oil production facility. Controlling this source of flaring often requires major capital investments in new equipment to manage, process or export the gas.

Building upon the information presented under *Historical and current data gathering and analysis* (page 30) and *Establishing company flaring and venting policy and procedures* (page 37), the remainder of this section addresses certain key aspects of the assessment and review stages involved in the selection of flaring reduction and gas monetization opportunities. Other elements of the process that are needed to take a flare reduction project from concept to implementation are covered in the 2011 guidance on flare management plans developed by IPIECA, IOGP and the GGFR[113] which describes a seven-step decision-making approach for flare reduction/gas utilization activities, as summarized in Figure 14. Readers are strongly encouraged to review this resource.

**Assessing local conditions and policies**

Constraints on allowable legal flaring activities, and conditions placed on the utilization of natural gas, are important considerations that frame any flaring reduction plan. Identifying and assessing these boundary conditions is an essential first step in the development of the plan. Compliance with local and regional regulations and policies covering environmental protection, safety/risk management, land access, etc. is essential. Such obligations can go beyond formal flaring reduction requirements mandated by local law. The applicable legal structures and commercial conditions covering gas resource and gas infrastructure ownership can significantly impact the choice of flaring reduction project activities. An understanding of the commercial environment affecting oil production and gas utilization is required to assess reduction options and facilitate the successful implementation of a project.

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![Figure 14 Flare reduction planning cycle](image-url)
Local stakeholders, NGOs and public expectations form another important context into which flaring reduction activities must fit. The API has developed guidance for effective engagement of local communities and other stakeholders. Where the government or NOC is an owner of the gas resource, there may be other non-project-related requirements set by the host government that will need to be considered (e.g. public welfare, international trade, national security, etc.). Flare reduction projects may also be shaped by government incentives, carbon taxes, and/or goals that call for the utilization of a certain percentage of produced gas in support of local industry or to provide gas to local communities, sometimes at reduced prices. Successful planning requires consideration of all such relevant factors.

Creating a thorough understanding of this context for flaring reduction in a region will lead to better choices in gas utilization and flaring reduction projects, and better prospects for successful implementation. The investments made to form or strengthen relationships with key partners, to build an understanding of issues and to create a climate of shared objectives, will drive successful flaring reduction programs.

Reviewing associated gas forecasts

As described in the section on Associated gas forecasts on page 30, the forecasting of associated gas is essential for developing an effective flaring reduction strategy. For legacy assets, knowing where to focus the activities of a flaring reduction program is key to achieving successful outcomes. Obtaining information on the different gas sources and flare points is essential, including mapping of all flared gas sources and volumes, compiling data on gas composition and pressures, and forecasting to understand the volume of gas flaring over time in order to justify the investment. However, there may be little direct measurement of flare gas volumes and compositions (especially in legacy operations), and many assumptions and estimates often need to be made when companies account for ‘waste’ gas, even for routine reports required by regulatory agencies.

For most operations, and especially for tight oilfields, an understanding of drilling plans, decline rates and GOR data will need to be factored into the analysis. As noted on page 30, a decline curve analysis coupled with drilling plans will set the baseline for production growth, and will help to identify whether significant temporal variations in gas production can be expected. GOR data can be used to determine the relative economic value of the gas and oil produced by a particular location, along with the value of the oil produced per unit of gas flared, as oilfields age or as new production techniques are employed.

Finally, the application of current data analysis tools will often yield further insights and aid in determining the set of priority high-volume flaring sources that dominate the overall picture, as well as other less obvious opportunities. Focusing flaring reduction efforts on these most important sources is the preferred initial approach, rather than devoting limited time and manpower to addressing sources of lesser impact. A general template is available for this type of identification process, which enables a large number of sources to be quickly and effectively broken down into a smaller number of distinct categories.

Developing a utilization strategy

With basic data on flaring volumes in-hand, identification of commercial project activities designed to address the priority sources of associated gas (based on the technology options described in the section on Flare gas-to-market options and principles on page 19) can proceed. For each combination of gas source and potential alternative use, information should be obtained to develop a preliminary scope (gas volume utilized and capital cost), expected timing and the high-level factors affecting successful completion of the project.

A first step in the process of developing a flare gas utilization strategy is to understand the volumes of associated gas that are available for monetization, as previously discussed.
Multiple levels of uncertainty and variability exist which, over time, make flare gas monetization challenging. Any oilfield’s production forecasts are statistically uncertain. This is recognized and is the reason why producers develop with P90, P50, P10 forecasts. This uncertainty also translates to associated flare gas volumes. (See Figure 15.)

Even at a set production level (e.g. P50), there is short-term variability in gas production, and over longer time frames, uncertainty. Figure 16 provides a conceptual associated gas production profile for a given oil production profile, illustrating the tranches of possible gas production volume over time from most certain (P90, V1) to least certain (P10, V4).

Only volume 1 (V1) is quasi certain and relatively constant over the life of the field and over the time period needed to amortize the investment in any gas capture and utilization project. Volumes V2–V4 become increasingly uncertain (and likely more variable) over time, making each tranche more challenging in terms of building a capture/utilization investment project.
Section 2
Flaring management—a framework for the oil and gas industry

The associated gas tranches (V1–V4) shown in Table 7 are important when developing a strategy for utilization that will be feasible and bankable.

To achieve zero routine flaring, and given that only production volumes with higher certainties are typically bankable (i.e. can support external financing), it is important to develop commercial/marketing/financing structures to address (de-risk) specific fuel/feedstock supply uncertainties.

By further separating this effort into technology review, project economic estimates and financial analysis, key causal relationships and sensitivities can be isolated and modelled. The procedural steps for developing a gas utilization strategy are shown in Table 8 on page 49.

After collecting data, and performing the analyses described above, it is helpful to construct a narrative or story for each of the cases using a common framework (example below). The process of synthesizing the information can reveal missing elements and hidden biases that a more granular analytical process sometimes misses.

The two basic strategies for reducing associated gas flaring, other than shutting in high-GOR wells are: capturing the gas and utilizing it within the field, or sending the gas to market by growing sales volumes to existing outlets or developing new markets and/or products.

Table 7  Associated gas tranches related to associated gas monetization opportunities

<table>
<thead>
<tr>
<th>TRANCHE</th>
<th>DESCRIPTION</th>
<th>BANKABILITY</th>
</tr>
</thead>
<tbody>
<tr>
<td>V1</td>
<td>Associated gas (V1) reserved for in-field use to facilitate oil production</td>
<td>Not applicable — gas is used for producer’s own consumption</td>
</tr>
<tr>
<td>V2</td>
<td>Operator may commercialize gas using its internal financial means or offer and guarantee this flare gas volume (V2) to a third party with the right risk/reward structure</td>
<td>Operator investment solution or with possible external investor</td>
</tr>
<tr>
<td>V3</td>
<td>With a bankable transactional and commercial structure, the objective is to bring this volume (V3) to the market, including by means of third-party investment</td>
<td>Multi-party investment solution, with essential investment grade building blocks and incentives</td>
</tr>
<tr>
<td>V4</td>
<td>Projects based on highly uncertain gas volumes (V4) must have company policy or government policy support and/or external financing, e.g.: a. zero routine flaring commitment b. concessional loans/grants c. regulatory framework: ban on routine flaring or a punitive (i.e. high cost) flare payment</td>
<td>Bankability is often challenging and requires creative business models and government/private sector collaboration</td>
</tr>
</tbody>
</table>
### Table 8: Key procedural steps for developing a gas utilization strategy

<table>
<thead>
<tr>
<th>PROCEDURAL STEP</th>
<th>CONSIDERATIONS</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Step 1:</strong> Identify associated gas tranches</td>
<td>See Table 7 on page 48.</td>
</tr>
</tbody>
</table>
| **Step 2:** Technology review | - What are the performance characteristics and risks of the technology?  
- How mature is the technology and has it been commercially demonstrated (i.e. conduct a maturity level technology assessment)?  
- How will it advance over time in terms of cost, performance and risk?  
- How does it compare to other existing and near future competing technologies?  
- What are the optimized configurations under likely use conditions?  
- What are the expected products and output rates?  |
| **Step 3:** Project economic estimates | - What are the relevant supply chain impacts and business schemes from flared gas source to market/end users?  
- What are the capital cost components, estimated values, sensitivities and uncertainties?  
- What are the GHG reduction potential and sustainability key performance indicators (e.g.: benefits from substituting gas for fuels with higher CO\textsubscript{2}e footprints; CO\textsubscript{2} avoided; cost-effectiveness in terms of USD/tonne CO\textsubscript{2}e reduced; aggregated sustainability index)?  
- What are the fixed and variable operating and maintenance costs, including plant turnarounds?  
- What are the expected product prices and revenue over the project lifetime?  
- What are the internal rate of return, net present value and net cash flow sensitivities from identified project risks including market demand and regulatory changes?  
- Is the project best executed by the production operator or by a third-party with special technology or more operating experience in gas utilization projects? |
| **Step 4:** Financial analysis | - What is the most likely method of financing the project (internal capital or external debt, equity or other financial sources)?  
- What is the company’s hurdle rate or minimum acceptable rate of return?  
- Which market conditions are necessary/sufficient for the technology to be deployed (product price, demand, growth, competition, regulations, global/national/industry economic growths, lending rates, risk perceptions, alternative investment opportunities)?  
- Are carbon credits or tax credits available?  
- Does an alternative case used for financial modeling include the impact of government mandated shut-in of oil production to reduce flaring? |
| **Step 5:** Other factors | - What government involvement or oversight is anticipated?  
- Identify the important hurdles that can affect project schedule, including: governmental authorizations; environmental permitting; land access agreements; product sales agreements; long-distance transportation logistics (e.g. trans-border pipelines; LNG shipping); etc.  
- What are the key stakeholder issues, mitigation options and costs?  
- What value chain risks exist and can they be mitigated through business structures, contractual arrangements or financial instruments (e.g. insurance)?  
- Are there opportunities to expand the boundaries of the project to include associated gas from other fields, even from those operated by other companies, to achieve economies of scale? |
**Own consumption**

Often, the least expensive options for flaring reduction are ones that can be carried out as part of the field’s operations, especially when the necessary equipment is available at the beginning of operations (e.g. reinjecting produced gas for pressure maintenance, gas lift or enhanced recovery, or using gas within the field for distributed electricity generation).

Gas reinjection in oil reservoirs is used to increase pressure in the formation to enhance hydrocarbon production. Gas lift, which is an artificial lift method that is different from gas reinjection, may be another option to minimize associated gas flaring, but only if the produced gas is captured, recompressed and reused. Associated gas injection for miscible-gas-based enhanced oil recovery (EOR) is an emerging technique that apparently offers some oil recovery benefit.\[^{118,119}\] In each of these use cases, the key determinant is the reservoir performance, with reservoir modellers and asset managers exercising judgement over the benefits of flaring reduction versus the potential operational and recovery risks of gas injection.

Associated gas can be used to generate electricity for a site’s production and related facilities, or for a centralized power system across the field. However, power generation is often more efficient when at large scale; therefore, a consideration is the trade-off between using gas for a site’s own consumption versus incentivizing centralized power generation systems (e.g. government-owned power plants with dedicated agreements with international oil companies for the feedstock gas).

In the case where a government resource owner or NOC is involved, the gas may be provided free of charge as part of the upstream production agreement. Electricity can be generated using small modular power units ranging from less than 1–3 MW capacity. If the production operations are dispersed over a wide geography, another option in lieu of pipelines is to compress the gas in field-based CNG units and then transport it by tankers to supply small-scale gas users (i.e. generators) elsewhere in the field. CNG reduces the volume of gas to be transported by 150–300 times that of gas at atmospheric pressure. However, logistics can be complex and costly for truck transport of CNG, absorbed natural gas, or virtual pipeline projects.

**Flare gas to market**

Strategies to monetize flare gas that go beyond use within the producer’s operations may involve significant capital expenditure, regulatory authorizations, coordination with downstream off-takers, stakeholder engagement and, sometimes, external financing. For such major projects, the producer may be the initiator and a key sponsor; however, when the flared gas transfer price at upstream facilities is low the project initiator and/or sponsor may be a third party.

Production of dry gas that meets a regional or national pipeline specification is the base case alternative for almost every gas monetization study. Assuming there is a market demand for gas, the key factors are gas quality and distance to the main gas transmission pipeline or, if no transmission pipeline is available, the distance to the consuming market.

Other than expanding in-field gas gathering and compression infrastructure to route gas to an existing (or new) gas transmission pipeline, opportunities include: CNG, NGLs, mini-LNG or GTL/GTC products. Alternatively, micro-scale technologies (e.g. micro-CNG, LNG, GTL) can be deployed at the well site or at central gathering facilities in the field. For larger, more comprehensive utilization projects (perhaps including more than one oilfield and/or production operator), substantial and consistent gas volumes are required. Such large-scale projects offer greater economies of scale and additional optionality, but require much larger financial commitments (e.g. USD billions) and involve greater commercial complexity. Because of large-scale project costs and complexity, the role of government in creating incentivizing frameworks to facilitate collaboration between producers is essential. Examples include world-scale LNG (typically for export), baseload gas-fired electricity generation (on a scale of hundreds of megawatts capacity or more) and chemical feedstock manufacturing (e.g. a USD 1 billion+ world-scale manufacturing plant).
Technology and economic assessment

The evaluation of gas monetization options is best done using a systematic approach to define the optimal solution. In addition to the technical considerations discussed above, commercial issues and market conditions also play a key role in the evaluation process.

The key question is what technology solution is commercially preferable under a given set of operating scenarios and market conditions. A systematic approach for evaluating the technical and economic feasibility of options to monetize associated gas are shown in Figure 17 (see also the supplemental information provided in Annex IV). Output from options analyses should identify and evaluate the main advantages and disadvantages of the candidate projects and the critical factors (i.e. technology, field operating regime, and market, regulatory, environmental and social factors) that impact investment decisions.

Figure 17  Technical and economic evaluation of alternatives to gas flaring

- Establish the basic data, e.g. sources of associated gas, and forecasted volumes, compositions, pressures, etc. (See Economic and technical considerations for flare gas reduction projects on page 22)
- Establish the context in terms of associated gas tranche (See Table 7 on page 48)
- Identify potential technologies that are applicable (See Flare gas-to-market options and principles on page 19)
- Assess technology maturity or readiness level
- Assess process safety aspects of technologies
- Assess deployability of technologies, depending on the existing infrastructure, market, business and bankability schemes (See Economic and technical considerations for flare gas reduction projects on page 22)
- Assess technical feasibility
- Assess sustainability or non-financial attributes, including country benefit analysis
- Assess economic feasibility, e.g. market price, capex, opex, net present value, internal rate of return, GHG-reduction KPIs (See Developing a utilization strategy on page 46)
- Evaluate sources of financing (See Green/climate change finance opportunities on page 52)
- Evaluate the bankability of the project (See Third-party funding opportunities on page 94, and Annex IV, Criteria, project screening and bankability on page 125)
Once options are identified, a screening process to reduce the number of options to a shortlist for a more in-depth analysis is undertaken. The screening process to shortlist (high grade) alternatives should identify the most important criteria to be considered in selecting the optimal solution. Typical decision criteria for screening alternatives may include, but are not limited to:

- Technical feasibility and project complexity;
- Capital and operating cost estimates for the specified technology solution;
- Alternative uses of investment capital and the producer’s cost of capital;
- Market demand and logistics for the gas or other products;
- Natural gas pricing (or other product prices) and price risk;
- Lease/concession terms and duration;
- Regulatory constraints and other factors governing access to gas utilization and export facilities;
- Proximity and capacities of regional and national pipelines;
- Additional operating costs associated with natural gas production and gas processing for each of the utilization options;
- Cost of land acquisition, and the cost and timing to obtain right-of-way approvals;
- Environmental and community impact analysis;
- Likelihood of legal challenges and concerns from stakeholder groups; and
- Regulations that define allowance flaring and the likelihood of future changes.

The economics of flaring versus capture and sales of associated gas can be difficult to assess. Consideration must be given to: oilfield operating plans and associated gas forecasts; gas capture/utilization technology; design parameters; capital, operating and maintenance costs; and operational cash flows, among other elements. The larger the scope and the number of parties involved, the more complex the analysis becomes. The section on Economic and technical considerations for flare gas reduction projects on page 22 provides an overview of the technical and economic factors that are relevant for gas monetization projects. After the shortlisted options are determined, further economic, market and risk analyses will be required. Ultimately, after a thorough evaluation of the alternatives, the goal is to select a project that makes sustainable use of all (or part) of the associated gas production.

**Green/climate change financing opportunities**

For large projects, where the required investment cannot be funded solely by the producer or the resource owner, the proponents can choose to pursue external financing (typically a loan) to initiate construction. Commercial banks are a traditional source of project finance. Another source of funding is green finance, which is focused on funding projects with positive environmental outcomes, and a sub-sector known as climate finance.

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Climate finance refers to local, national or transnational financing — drawn from public, private and alternative sources of financing — that seeks to support mitigation and adaptation actions that will address climate change. Climate finance is sourced either from capital markets or government budgets, and channelled through various multilateral and bilateral agencies and a multitude of private financial intermediaries. Annual flows of climate finance funds have reached more than USD 500 billion and the trend indicates a continuing increase, as shown in Figure 18.

There is much innovation in the area of green finance, and new products are being developed to marry the desire to fund climate-focused projects while providing an attractive return for investors. The section on Third-party funding opportunities (page 94) provides an overview of other financial resources that may be available to a particular project. More detail on lender considerations are discussed in Annex IV.

The use of green bonds to finance environmental projects has grown significantly. For issuers, green bonds are a way to tap the USD 100 trillion pool of long-term private capital managed by global institutional fixed income investors. This shift to capital markets from banks is also having a beneficial add-on effect, in that it is ‘freeing up’ limited bank balance-sheet capacity for early-stage project financing and infrastructure lending. However, because there is no single set of agreed-upon criteria describing the projects that qualify for green bond financing, projects that are based on hydrocarbons (such as flare gas capture to fuel electricity generation) may face headwinds. Nevertheless, a flaring reduction project has been linked with the issuance of green bonds, and can serve as a guidepost for large-scale flaring reduction projects in particular circumstances. “Transition financing” is a term that has been used to categorize those instances where climate bonds have financed certain investments that can make a substantial contribution to halving global emissions levels by 2030 and reaching net zero by 2050.

Another option for climate-related financing that has been used to monetize associated gas and reduce continuous flaring is the use of carbon credits. These are tradable instruments based on emission reduction projects that are registered in voluntary or regulatory programs, and generate carbon credits that can be monetized to enhance the returns on a flaring reduction project, or retired to count towards meeting a company’s internal GHG reduction goals. Voluntary carbon credit registries include: the Gold Standard; Verra; the American Carbon Registry; the Joint Crediting Mechanism in Japan; and the Climate Action Registry in California.

Figure 18  Total global climate finance flows, 2013–2018

<table>
<thead>
<tr>
<th>Year</th>
<th>Total</th>
<th>Trend</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2014</td>
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<td>2017</td>
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<tr>
<td>2018</td>
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Another legacy carbon credit mechanism was set up under the CDM, which includes a specific methodology for project activities that recover and utilize associated gas and/or gas-lift gas from oil wells, which would otherwise be flared or vented prior to the implementation of the project activity. A list of select, well-documented gas flaring reduction projects registered under the CDM is included in Annex V. Although not a viable mechanism for new projects, the CDM may be noteworthy as a foundation for carbon trading under Article 6 of the Paris Agreement, as the specific rules and modalities evolve.

**Joint venture business model**

Implementing a gas monetization/flaring reduction program at scale can challenge the internal resources of a single oil and gas producer. An approach that can facilitate the process involves partnering through a joint venture (JV) with other companies that have the necessary resources and required expertise. Some of the reasons commonly cited for entering into a JV (upsides) and potential risks (downsides) are covered in Table 9.

<table>
<thead>
<tr>
<th>UPSIDE</th>
<th>DOWNSIDE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pairs complementary players from different industry sectors</td>
<td>Cultural differences between parties from different jurisdictions can lead to misunderstandings and inefficiencies</td>
</tr>
<tr>
<td>Economical long-term resource commitment with shared risks</td>
<td>Misalignment or divergence of strategies can result in losses and a failure to achieve overall business objectives</td>
</tr>
<tr>
<td>Lower technology development costs</td>
<td>Operational problems from strategic differences, production issues, management control issues or otherwise, can limit the effectiveness of the venture</td>
</tr>
<tr>
<td>Knowledge sharing</td>
<td>Lack of trust between the parties can limit cooperation</td>
</tr>
<tr>
<td>Diminished political risk (e.g. government oversight, nationalization, political volatility)</td>
<td>Decision-making and dispute resolution processes can be lengthy and costly</td>
</tr>
<tr>
<td>Enhanced credibility for external financing</td>
<td>Service and contribution agreements can create a dependency of the joint venture on a particular party</td>
</tr>
<tr>
<td>Faster time-to-market</td>
<td>Exit upon termination can be expensive or difficult</td>
</tr>
</tbody>
</table>

Oilfield JVs focused on upstream production are a common model for sharing capital investment and risk. Monetization of associated gas offers a different opportunity for forming a special-purpose JV with another entity, especially where the production operator and NOC are in a JV for the purpose of exploiting an oilfield. The special-purpose JV for gas can include a technology provider (e.g. GTL, LNG and CNG) or a state-owned utility, such as in the case of a project to build a gas-fired electricity generation plant.

In Ecuador, with the assistance of the GGFR, Petroamazonas EP has advanced conceptual engineering for monetizing stranded associated gas from multiple small sources. This innovative virtual pipeline project proposes to use a private-sector-driven solution that captures, stores, transports and offloads untreated gas from multiple flare sites to power generation and/or processing facilities using a network of specialized trucks referred to as a ‘virtual pipeline’. Ultimately, this gas will be used to displace diesel for power generation and/or to produce natural gas-derived products. A JV business model analysis is well-positioned to mobilize private sector financing for the virtual pipeline project.
Third-party ‘design, build, own, operate and maintain’ model

An engineering, procurement and construction (EPC) project is a very common approach to adding major facilities to an oilfield operation. The EPC contractor is responsible for all activities from design, procurement and construction, to commissioning and handover of the deliverables to the owner or operator. This design-build model leverages crucial design know-how from the EPC contractor to improve the performance of a project during the development phases (i.e. design and construction).

However, where there is a fragmented contracting strategy, with the project scope being split among different contractors at various phases of the project life cycle, management of the interfaces will be complex and often inefficient. In the absence of a commercial incentive for contractors to minimize costs for the subsequent phase of the project, the responsibility for optimizing costs during the project life cycle will fall with the owner/operator. Over the life of the facility, operations and maintenance expenses often far exceed the initial cost of a facility. Importantly, the decisions made early in a project have a strong effect on the life cycle costs. Typically, owners/operators have the responsibility and incentive to see that operations and maintenance considerations are incorporated early in the design process.

The traditional EPC project model can work well when the owner/operator has deep experience with the technologies and processes that comprise the capital project. For some flare gas reduction/gas monetization projects, especially those involving new technologies, knowledge can be heavily weighted to the technology provider. In such cases, an alternate project model may be better than the EPC model. For example, the design-build-own-operate-maintain model involves executing a single contract where a third-party is placed in a position of ownership (of the technology employed) and is made responsible for the design and construction, as well as the operation and maintenance of the installed solution. This model incentivizes the contractor to deliver an engineered solution that reduces the construction cost and minimizes operational and maintenance costs by ensuring that the contractor has a significant financial stake in the long-term performance of the solution. Such an arrangement better aligns the commercial interests of the contractor and operator. Essentially, the more gas that can be managed through the solution, the higher the financial reward that accrues to the contractor. Turnkey solutions for GTL, GTC, small-scale LNG and distributed GTW, especially those that involve novel technologies, are amenable to such models. An alternative business scheme, where the technology provider is also part of a JV with the owner and/or producer(s), may be even more effective at sharing the risk amongst parties (see joint venture business model on page 54).

Another emerging business model is where a company acts as a unique and single source of project coordination and responsibility for execution of the technical project, selection of technology, and coordination of the EPC contractor, off-taker and seller of the products. The company can also assume the role of interfacing and liaison with the NOC and other company partners, and can provide project financing, as well as the finance structure of the project to make it bankable.

MANAGEMENT OF NON-Routine FLARES

Non-routine flaring covers a wide spectrum of situations, related primarily to operational anomalies, unexpected outages or maintenance activities. Planned events leading to non-routine flaring, such as scheduled maintenance, periodic turnarounds and start-up of equipment, can often incorporate strategies to minimize the volume of gas sent to flare (e.g. use of nitrogen instead of gas for turbine starts). Although the timing of any particular unplanned event may be unpredictable, these types of events are foreseeable in that they have occurred at some time in the oil and gas industry. In fact, the longer any particular facility or production operation exists, the more historical data are available to identify the circumstances that underlie such events and the resulting flaring consequences. A process to establish these common causes of flaring, also referred to as root cause analysis (RCA), is one of the most important elements in a corporate program to enable effective reduction in non-routine and upset flaring.

Even when a review of past data identifies opportunities to address the causes of non-routine flaring, it can sometimes be a challenging business case to do so, if the only criterion used is a cost/benefit analysis based on the gas recovered (unless oil production is also curtailed due to equipment reliability issues).
Often, the value of the associated gas flared is very small compared to the oil produced. This is especially true in a liquids-focused operation, where capital spent to prevent gas flaring can have a much higher return if used to drill an additional well or perform workovers on an existing production well.

However, restricting the decision-making test to the value of gas recovered is considered too limiting in today’s operating environment. Consideration needs to be given to other factors, including: environmental performance; regulatory requirements; local community concerns; public reputation; preferred partner status; investor perception; and employee messaging. These factors can all affect a company’s ‘social license to operate.’ If non-routine flaring negatively impacts a company’s reputational profile to the point where it limits the company’s ability to continue to maintain or grow its oil production, the cost/benefit calculation can have a dramatically different outcome.

The following sections describe an approach that can be used to assess non-routine flaring, with a view towards making strategic investments that will reduce it to as low as reasonably possible. The approach begins by making the organization aware of the issue and the need for it to be managed. The management-level goals that frame the desired outcome are then established, along with a strategy for achieving them, and specific targets. A basis for action is then developed by identifying operational practices that contribute to flaring, and any good practices that have been implemented to reduce equipment failures that lead to flaring (e.g. proper spare capacity). The implementation also includes a method to handle unexpected challenges, and an investigation and decision process to identify and prioritize those situations that require remedial action. A final aspect covers rotating equipment and equipment sparing.

The API announced The Environmental Partnership in 2017 to accelerate improvements in environmental performance of operations across the US. More than 80 partner companies have committed to the responsible development of US energy resources while reducing emissions. An important component of the Partnership’s actions is a program that is focused on reducing flaring in upstream operations through advancing best practices to reduce flare volumes, promoting the beneficial use of associated gas, improving flare reliability and efficiency when flaring does occur, and collecting data to calculate flare intensity as the key metric to gauge progress from year to year.

Figure 19 Flare control communication

- **Planning and communication**
  - Reduction goal set by senior leadership
  - Promote culture through management engagement (e.g. approval of planned flaring over 24 hours)
  - Continuous gas capture planning and commitment with midstream
  - Enhanced reporting
  - Engage with regulators

- **Upsets and unplanned events**
  - Tools to increase awareness of volume and cause throughout the organization
  - Assess facility design to enhance gas-oil separation and reliability
  - Implement process to evaluate flaring events

- **Operational controls**
  - Improve gas quality for pipeline
  - Enhance separation reliability
  - Gas treatment
  - Compression assessment, including reliability

- **Technology as an alternative**
  - Case-by-case evaluation of beneficial-use technologies, e.g.: mobile gas processing for NGL transport
  - CNG production for on-site use or transport
  - Reinjection for storage or deferred production
  - On-site power generation

- **Optimize combustion**
  - Manage emissions when flaring is necessary via:
    - auto igniters
    - remote or on-site monitoring
    - use of automation
    - redundant ignition
    - maintenance programs

Reduce volumes of flared gas
Minimize emissions
The Texas Methane and Flaring Coalition issued a report containing its preliminary recommendations for reducing flaring and improving environmental performance in the State of Texas. The Coalition’s development of ‘best practices’ was based on a chain of communication to evaluate operational and technical considerations related to flaring of gas, with the goal of minimizing flaring and, if it must occur, how best to manage flaring practices. This process (shown in Figure 19 on page 56) outlines a way to ensure a comprehensive review of flaring, and the identification and implementation of the most effective solutions for its reduction.\[130\]

**Raising awareness, and visualization of flared gas**

Non-routine flaring is distinguished from routine flaring by the cause, magnitude, frequency and duration of flaring events. Non-routine flaring is generally characterized by infrequent occurrence, high-emission rates and short event durations (each company has its own internal definition for the duration of a non-routine flaring event, ranging from sub-hourly to several days). By its very nature, non-routine operational flaring can be difficult to predict and track in the absence of adequate flare metering. Unexpected process upsets that are outside normal steady-state plant process and equipment operations, equipment breakdowns, and miscommunication between operations personnel and service providers are among the reasons why such flaring occurs, and can contribute to its unpredictability.

Data for non-routine flaring events can be difficult to obtain, especially from unmanned or lightly instrumented locations. Where available, data can be obtained from process control system logs, data historians or production accounting systems. The duration of non-routine flare events is a key parameter and is often required for regulatory notifications. Accurate volumes can be estimated or calculated during or after the actual flare event, since they are often time-dependent and many variables are involved. If a total-flare-gas meter is available, an estimation of flare gas volumes will still be required to allocate flare volumes to individual flare sources if more than one flare source releases to flare during a specific flaring event.

The important information associated with non-routine flaring includes:

- the length of time the inlet process valve was open during a process overpressure situation;
- the length of downtime for required utilities (electricity or instrument air);
- the length of time required to identify which process should be isolated on a control system or in the case of instrument failure;
- the length of time required to identify and isolate a failed valve/component;
- whether a failed component can be automatically or manually isolated; and
- whether the event was caused by operator error.

Many locations in the oilfield are unmanned and have only basic monitoring instruments, so flaring can go undetected for a period of time. However, advances in remote sensing by satellites have led to the development of tools that can be used to survey large areas and reveal instances of flaring.\[131\] Figure 20 shows flaring data in the Permian Basin. The visualization is based on data captured by VIIRS instruments onboard NOAA satellites, and collected by the Earth Observation Group, Payne Institute for Public Policy.\[132\]

**Figure 20  Satellite image of flaring in the Permian Basin**\[133\]

Other organizations are using satellite data, aerial surveys and fixed ground monitoring stations to cross-reference instances of flaring. Analysis of data from the wells and facilities in the Permian Basin showed that 11% of flares were malfunctioning, including nearly 5% that were unlit.\[134,135\]
Section 2
Flaring management—a framework for the oil and gas industry

To reinforce the need to address non-routine flaring, a company program focused on flaring reduction, including non-routine flares, should publish dashboards of information, including time-series charts and other visual graphics that plainly illustrate the volume of gas lost due to non-routine flaring for the company as a whole, as well as by key operating areas. Data can be sourced from production accounting systems and/or from flaring incident reports submitted to regulatory agencies. At a minimum, data should be presented in terms of absolute volume and intensity (i.e. non-routine flares gas volume divided by the volume of gas produced).

Flare management during non-routine/unset scenarios

To be effective, any initiative to reduce non-routine flaring should be built upon a robust policy and management system to drive implementation. It should begin with a clear commitment from management to minimize, or aim for the complete elimination of, non-routine flaring, except for those instances that are safety-related. A signed statement that frames the goals and establishes a target date for implementation with interim milestones is a powerful motivator to the rest of the organization. This message should be communicated to the internal stakeholders that have the operations responsibility, and to the planning/finance sections along with critical support groups such as engineering, supply chain, information technology, asset reliability, and environment and safety staff.

A senior operations manager should be named as the initiative sponsor. This person, supported by staff, will: provide focus; sanction targets for individual operating units and hold those units accountable for performance; oversee a waiver process for extraordinary situations; provide appropriate flare avoidance training to operators; ensure that the staff groups and line operations teams are in alignment; negotiate with planning groups and finance managers to obtain the necessary capital to fund the improvements; and communicate successes to encourage further achievements.

Generally, the identification, screening and prioritization of operational enhancement projects can follow the approaches for routine flaring described earlier in this document. An important element to facilitate ongoing success is a thorough RCA process for non-routine and upset flaring, making certain that the process does not stop at the first proximate equipment-related cause, but digs down into management systems and commercial matters (e.g. contracts with gas off-takers and suppliers of equipment and services). Finally, data system enhancement may be necessary to monitor and track performance and support the linkage between non-routine flaring reduction metrics and individual compensation.

Review of operational controls and processes

Non-routine flaring occurs at the well head as a result of drilling, completion and flowback activities. Flaring occurs at field locations, including gas gathering or processing facilities, due to planned maintenance and unplanned upsets or malfunctions. When components exceed design parameters such as allowable pressures, emergency relief devices automatically route the gas to a flare to maintain safety, usually for a period of minutes or hours. A compressor engine failure on a low-pressure gathering pipeline system can create unanticipated back-pressure in the system; this in turn can cause relief valves at upstream production facilities to send gas to flare automatically. Equipment failures and upsets at downstream gas plants can create non-routine flaring at distant upstream production locations because take-away capacity is reduced or completely shut in.

The identification of potential flare source locations can be determined through a review of as-built piping and instrumentation drawings or on-site inspections. All process piping discharges into the flare header should be followed back to determine their origin. For example, process drains discharging into the flare knock-out vessel could also be a potential for flaring in the event of: a failure of one or more low liquid level alarms in the process vessels; drain valve leakage; or operator error with respect to manually operated liquid drain valves.

A list of typical non-routine flare sources is provided in Annex VI.

More detailed methods of tracing flaring to its sources include analysing alarms and other process anomalies (e.g. low/high flow, high pressure, etc.) from data historians, for distributed control systems or central control room systems. Maintenance management systems can be queried for work orders associated with flaring events to identify failed instrumentation or process equipment.
Sampling and analysis of flare gas composition may be able to help identify the sources of gas. Process hazard reviews or revalidations can identify whether as-built systems match the original design layouts.

In reviewing processes and facilities, the design aspects that most affect the volume and duration of non-routine gas discharges to flare include: piping design; equipment sizing; equipment choice/specification; and instrumentation/control. Addressing these aspects can significantly improve the frequency and volume of non-routine flaring. Further information on good design considerations for each of these aspects[136] is included in Annex VII.

Setting flaring targets at the station level

Field-level targets for non-routine flaring reduction at operational locations should be aligned with a company’s strategy, reflect the operational environment and competitive landscape, and should fit within the context of its culture. However, targets alone are not a strategy. Instead, targets flow from the strategy-setting process. The specific metrics chosen, and the levels to be attained by a certain time (i.e. the target), should be informed by the intent behind the strategy so as to drive an organization’s progress towards the desired goal. If the strategy is poorly developed, a set of targets cannot fill the gap. If the targets are not aligned with the goal, it is unlikely that the preferred outcome will be achieved.

Flaring targets can be based on the volume flared for a given period (e.g. total volume), volumetric rate (e.g. volume/day) or volumetric intensity (e.g. volume/volume). Absolute targets are used to drive towards a new end state or operating regime. They tend to connote a transformation. Intensity targets drive progress in relation to the way things used to be. Relative targets connote gradual evolution. Because each has a specific purpose, combining multiple types of targets can yield a more effective outcome than using just one.

Absolute target

Performance against an absolute target is easily measured; it is pass or fail. For existing producing assets, imposition of an absolute non-routine flaring target, where none had been in place before, can create organizational friction. To mitigate the understandable resistance, the target-setting process is best done in a collaborative manner with full engagement from the operations team. Furthermore, establishing the target should account for its inherent shortcoming, namely, that it does not account for growth in the volume of gas handled, which is in direct proportion to the growth of oil production (and revenue).

Consequently, a reasonable absolute target for flare volume should be adjusted annually to reflect changes in activity (i.e. oil and associated gas volume production) and reflect the ambition to reduce flaring to promote change. In addition, it should reflect the inherent reliability of the installed gas management/recovery system, any planned outages for safety or maintenance, and the historical incidence rate of unplanned outages of the production system that contribute to flaring. Typically, an asset team will recast an annual absolute target into a daily or weekly rate target to facilitate tracking and trending, and to inform daily/weekly/monthly operations plans.

Intensity target

Targets normalized on an operating parameter are less rigid than absolute targets and can offer an easier path to acceptance for an organization that is not accustomed to having targets for non-routine gas flaring. However, a normalized target does not cap the total volume flared, and hence it allows for production increases.

A normalized flaring target uses the same structure presented above, but normalizes the allowable gas flared by the total gas throughput to transform the target into a simple parameter, i.e. percent flared. This parameter can be tracked easily and at any time by the asset team to determine conformance.

Example calculations for absolute, rate-based and intensity targets are provided in Annex VIII.

Framework for variance and waivers

Flaring targets act as key performance indicators against which flaring volumes, rates and/or intensities at a flare location can be compared and tracked on a daily/weekly basis. Inevitably, there will be situations where flaring at a particular location trends above its target for a reason that was unforeseeable, or was beyond the ability of the operations team at that location to rectify the cause in a timely manner. In such cases, and for the right reasons, the organizational flaring policy should include a flaring waiver process.
A flare target waiver may be necessary for a variety of reasons, including: maintenance of safe operations, equipment and system reliability; failure of third-parties to perform (e.g. gas processors and other off-takers); delays in equipment repair or replacement beyond historical norms; a contractual or other legal obligation; etc. These are significant, weighty reasons that exceed the capacity of line operations to respond. Meeting production targets should not be the sole driving justification for a waiver.

The structured process should be overseen by the senior operations manager who has been named as the organizational sponsor for the flaring initiative. This person can balance the impact on the company’s strategy and determine how such a waiver would affect the achievement of flaring reduction milestones. The waiver process should include:

- timely notification of an equipment upset or malfunction, or other situation that requires a target waiver;
- an estimate of the duration and volume of gas to be flared;
- a description of why the situation warrants a target waiver versus some other course of action, for example obtaining temporary equipment to handle the gas flow, a shut-in of oil production or a shutdown of gas processing facilities;
- an obligation imposed on the requestor (i.e. the operating location line manager) to perform a formal root cause analysis investigation to determine the causative factors that lead to the situation that the flare target waiver request is meant to address;
- an assessment of the resources and time required for implementation of temporary mitigations and permanent corrective actions; and
- a commitment by the location staff to resolve the problem according to a specified schedule.

**Economic and technical risk assessment**

A waiver of a target, which can be thought of as a management of change authorization, should be based on the principle that the residual risk shall be reduced as much as reasonably practicable. In the context of a flaring waiver, an ALARP analysis emphasizes the management of risk up to the point where the costs of risk elimination exceed its benefits.

In oilfields where the necessary infrastructure exists to capture and utilize petroleum gas associated with oil, routine flaring is minimized. However, if there is a failure of this infrastructure, or some other situation that prompts a waiver request, there is a possibility of above-target non-routine flaring. In a business environment that favors ongoing oil production over gas conservation (because of price differentials), a decision to flare the associated gas may seem logical, especially if flaring is allowed under applicable laws and regulations. The positive revenue from additional oil production is a powerful driver for decision-making. However, in the absence of a robust cost-benefit analysis, such a choice can lead to the inappropriate management of risk, which includes loss of gas revenue and the creation of environmental and social impacts.

If the decision is framed as one that pits the continuation of oil production (with gas sent to flare) versus shutting-in production from the affected wells or other operations, the apparent economics will almost always favor the continuation of oil production. It is only when a more robust assessment is conducted that other aspects may weigh more heavily. As noted earlier, consideration should be given to factors such as local community concerns and public perception. The allowance of non-routine flaring in the face of a public commitment to eliminate such practices could erode a company’s reputational profile to the point where it limits the company’s ability to continue to maintain or grow its oil production. Another issue that needs to be weighed is the impact of granting a waiver based on the internal perception (within the company) of the non-routine flaring strategy. Each waiver serves to weaken the belief that management is committed to its success, which could undermine the entire effort.

Careful analysis of each of these factors during the waiver decision-making process will provide a richness to the cost-benefit calculation beyond one that is simply based on revenue.
Flaring management—a framework for the oil and gas industry

Root cause analysis and identification of ‘bad actors’

A ‘bad actor’ program is designed to identify the operational factors and/or equipment that lead to recurrent upsets that result in non-routine flaring. It is based on the Pareto principle, i.e. 80% of the issues come from 20% of the causes.

The strategy to identify ‘bad actors’ involves an RCA of production-related upsets based on the impact of each flaring event. RCA is the application of approaches, tools and techniques to uncover the causes of such events. The primary aim is to identify the factors that resulted in the flaring event, the nature of the occurrence, its magnitude (e.g. volume flared and lost production), the location, and the timing of the consequences. This information will allow a determination of the behaviors, actions, inactions or conditions that need to be changed to prevent the recurrence of similar outcomes. The results of the RCA are typically documented to provide a record of the incident investigation, corrective actions to be implemented, and details of lessons learned.

With respect to non-routine flaring, the proximal reason why a particular flare event occurred may be obvious, for example a safety valve sending high pressure gas to a flare. However, the determination of the root cause of an event usually involves an investigation or engineering analysis of the circumstances leading up to the actual flare event. For example, the cause of the overpressure could be due to a disruption in the normal flows of material that causes a blockage or high-pressure zone in some part of the system. Although overpressure will be identified as the immediate cause in many (if not most) non-routine flaring events, the primary causative factors in a failure sequence that leads to an overpressure scenario include:

- initial production from a well being higher than anticipated;
- downstream take-away capacity is constrained;
- power failure;
- control system failure or set-point design error;
- relief valve failure or set-point design error;
- check valve failure;
- instrument air failure;
- vent gas system pressure imbalance;
- compressor failure;
- pump failure;
- ineffective liquid seal on the flare system;
- a blockage in piping or at the discharge point of a process or process equipment;
- unanticipated thermal expansion within a confined volume;
- leakage around valve seals;
- large slugs of liquids being sent to an inlet separator;
- a training gap; and
- other facility design and/or operational practice gaps.

The investigation or engineering analysis of an event that results in flaring should consider the overall context, which is to enhance profitability while striving to maximize safety and on-stream production time through more reliable equipment and process systems. Consequently, an RCA should yield useful information when it is focused on equipment or systems that experience one or more unscheduled shutdowns or failures during a specified time period that lead to a flaring event.

Targets for in-depth investigation can be identified through queries of maintenance management systems that look at classes of equipment for repair costs and the number of outages by equipment type. Flaring waiver requests can also evaluated. Graphical depictions (Pareto charts) can also be developed showing the frequency of flaring, the cost of repairs and the extent of lost production. From this analysis the important ‘bad actors’ can be identified, and a more detailed action strategy can be developed to address them.

The RCA should look for primary and contributing causal factors by examining:

- the inherent design of the equipment or system;
- a defect in the material of construction or a system component;
- faulty equipment build or system logic;
- errors in the way that the equipment or system was installed;
- inappropriate equipment or system for the operating conditions;
- inadequate maintenance procedures; and
- improper operation.
Common elements in most programs aimed at identifying ‘bad actors’ consist of the following:

1. Defining the scope of the analysis, either to consider the whole operation (entire field or gas plant) or limited portions (certain well sites or production facilities) over a selected time period. A broader scope requires more work, but is likely to identify unanticipated trends.

2. Obtaining flare event logs and work order histories from the computerized maintenance management system for all in-scope assets.

3. Performing data cleansing/validation to eliminate duplicate or false records, completing partial data records and obtaining maintenance and associated downtime/lost-production costs.

4. Preparing Pareto charts in which operations or equipment that cause larger flaring volumes and lost-production costs rank higher than others.

5. Selecting the top 20% from the dataset for further review — these are the ‘bad actors’.

Ultimately, the key to a good RCA program is to have a broad, knowledgeable team involved in performing the analysis, and the right data to review.

Focused strategy for addressing ‘bad actors’

Many studies have shown the cost of unplanned and emergency work is about four times the cost of planned work. This is due to pulling people off planned jobs to address emergencies, the lack of a response plan and spare parts, and higher spend rates due to overtime or premium pay and suboptimal sequencing of work. The interruption of planned work can cause employee performance to decline, and may put personnel at greater risk of injuries. Asset protection is also a major consideration. These risks all increase when equipment fails unexpectedly and there is pressure to restore operations.

The strategy for addressing identified ‘bad actors’ to ensure lasting improvement is part technical, part managerial. The technical part involves analysing the contributing causes behind the ‘bad actors’; this is also known as failure mode classification. The failure modes are then compared against the procedures/activities that are already in-place to prevent such failures. If a preventive maintenance or operations procedure already exists for an identified bad actor failure mode, the procedure will need to be reviewed and enhanced — either the frequency will need to be changed, a new feature(s) may need to be added, or the training curricula need improvement.

If a failure mode is identified:
- a new preventive maintenance or operations procedure will need to be developed; or
- an engineering study will need to be undertaken to identify an appropriate replacement part, equipment or system for the one that has failed.

When recurrent issues are identified, a review of the equipment sparing philosophy or an increased inventory of key spare parts may be worthwhile. After a new solution is identified and a process design completed, the normal project workflow can be established (e.g. funding, planning, purchasing, installation and field commissioning).

The key to an effective, lasting solution (for any of the cases noted above) is to conduct a performance evaluation of the implemented solution. It is equally important whether the RCA identifies equipment, or human factors or procedures, as being at the core of the bad actor issue.

A final element — communicating successes — can create significant leverage and drive further progress in addressing non-routine flaring driven by ‘bad actors’. A managed program to communicate real examples of the positive work done to eliminate the underlying causes of flaring can have a multiplier effect throughout the organization. It can break down the silos that often arise, and which prevent operations teams from engaging with maintenance teams or with staff groups such as engineering or asset reliability personnel. Furthermore, when an organization sees a demonstrable commitment to upgrade systems and processes — whether by hiring specialized contractors to undertake analyses, or by spending capital to replace outdated or inferior equipment — rather than narrowly focusing only on production, this will foster a culture that does not tolerate upsets that lead to non-routine flaring.
Rotating equipment and sparing strategy

Rotating equipment is a term used in the oil and gas industry to describe a class of mechanical components that use kinetic energy to move fluids, gases and other process materials. Turbines and gas compressors are the most important examples employed in the management of associated gas. The operational reliability of compressors can determine the success of an associated gas capture and utilization project.

Significant considerations involved in the choice of compression equipment include cost (i.e. capital, installation, operating and maintenance costs), operational flexibility, reliability and emissions. The capital cost for a project involving gas compression includes the driver and the compressor, along with their installation, as well as the necessary ancillary components and instrumentation systems. Spare units, including those used during start-up and commissioning, should also be considered.

A gas capture project should consider the flexibility needed for different operating regimes and for scenarios that arise from failures of one or more systems. Operating conditions can vary due to changes in gas supply (e.g. depleted fields or new wells) and demand by downstream off-takers, or changes in gas composition. Using multiple smaller compressor units rather than one large unit can be another way to provide flexibility.

The designed availability of equipment also needs to be factored into the project. Availability accounts for equipment downtime due to planned and unplanned events. It is often expressed as the ratio of run time to planned production time (where run time is the planned production time less any down time due to planned or unplanned stops). The cost associated with availability is directly related to the inability of the process to perform at the designed rate on an annualized basis, and this has a direct impact on the likelihood of a project earning its expected economic return.

The unavailability of compression due to maintenance or an unexpected upset can cause significant loss in revenue in the gas utilization project. The installation of spare or standby units is an important consideration, despite the additional capital and installation costs. Although upsets or emergencies cannot be predicted, the scheduling of maintenance shutdowns can, and planned outages should be performed when lower capacities are required.

Spare units can be arranged such that each compressor station has one spare, but this can be costly where there are several processing plants in multiple fields. This prompts other considerations, including how to use the standby compressor. For example, a decision to operate with a dedicated spare, rather than operate both pieces of equipment at partial loads (inefficient), or to alternate units running at full load (frequent high-stress start-ups), ensures that a serviceable unit is immediately available when the other fails. It also means that it is unlikely that both units will reach the end of their lives at the same time.

Another approach is the standardization of compressor makes, types and models across the entire operation of a company, such that one swappable standby spare is kept for several compressor stations. When the standby spare is used to replace a defective compressor at a particular station, the replaced compressor is repaired and then becomes the new standby spare for use if another compressor failure occurs at the same station or at another plant. This approach has the potential to significantly drive down the cost of standby sparing for compressors.

The life-cycle cost comparison among strategies typically requires a statistical simulation based on historical data, which includes:

- failure consequence and occurrence rate to inform a criticality assessment;
- failure mode and effects analysis to identify dominant failure modes and possible risk mitigation tasks;
- the frequency and characteristics of each failure mode;
- maintenance data; and
- information on spares, i.e. purchase price, storage cost, lead time, depreciation, and categorization of logistical availability.

In determining whether to adopt a standby or a shared-spare philosophy, consideration should combine life-cycle costs with risk tolerance. For a standby philosophy, the initial number of compressors will be twice the number required for design rates, but the redundancy may be warranted where uptime is the driving factor. For a shared spare, the initial number of compressors will be lower, equal to the number required for design rates plus a certain number of spare units. With a higher risk tolerance for outages, the number of spares will be lower. The final number will depend on balancing the desire to minimize gas flaring with the cost of providing (and maintaining) shared spare compression capacity.
A study [139] of non-routine flaring incidents in different production stations located across Oman was performed to identify the ‘bad actors’ that contributed to the frequent equipment failures. The stations experienced high flaring frequency and volume compared with other stations. Analysis of historical data showed that the chiller compressor, gas recovery compressor and gas injection compressor were the most frequent failure cases.

Midstream gas plants

Processing natural gas to achieve pipeline quality dry gas, and separating the NGL fractions, is complex and encompasses four main processes:

- Oil and condensate removal.
- Gas dehydration.
- Separation of NGLs.
- Removal of sulfur, CO₂ and other impurities.

Like any other complex hydrocarbon processing facility (e.g. a refinery), a midstream gas processing plant can experience operational upsets and equipment failures, such as a compressor outage. However, unlike a refinery with significant crude oil storage ahead of the processing units, a gas plant does not operate in an isolated fashion. It is linked directly to upstream facilities; there is no intermediate storage between the upstream producing facilities and the gas processing facilities.

Scheduled and unscheduled maintenance or a process upset can shut down portions of a gas plant facility (e.g. the fractionation section). If this occurs, the affected section can be isolated, and feed gas sent to flare. Maintenance or an upset at the input side of the plant will likely require the stoppage of all gas flows into the facility. In this circumstance, the gas flows can be directed to the plant’s emergency flare system, or may cause flaring at upstream production locations as the shutdown cascades backwards through the low-pressure gathering pipeline system tied to upstream production facilities.

Midstream transmission lines

Water and natural gas liquids can condense in gas transmission pipelines, creating a safety hazard. Periodic clearing of the pipelines is therefore required. This is undertaken using a process referred to as ‘pigging’ (see page 39), which clears the liquids from the pipeline. During this process, the gas in the pipeline network is sent to a safety flare. It is considered good practice to recover flared gas from pigging operations into a lower-pressure fuel gas system. If a build-up of liquids in a gas gathering system is not cleared, and arrives unexpectedly at an intermediate midstream facility (e.g. a mainline compressor station), it can cause a significant upset at the facility and at upstream facilities.
LNG

Flaring in the LNG value chain is primarily associated with the evaporation of LNG. Evaporated LNG is commonly known as boil-off gas (BOG). It is generated during the production, storage, loading, transportation and unloading of LNG (see Figure 21). BOG losses in the one-way movement of LNG from loading to unloading can amount to more than 9% of the total LNG carried; with loading processes accounting for 2.7%, shipping for 2.7%, and unloading accounting for 4%.[140] At LNG plants and export terminals, BOG generation is caused by five main factors:[141]

1. Depressurization of LNG.
2. Heat leaks through containers and pipelines.
3. Tank breathing.
4. Heat added by equipment, e.g. pumps.
5. LNG-carrying vessels being hot before loading of LNG.

BOG is also generated during transport in LNG carriers, and during offloading and storage as the LNG is introduced into de-inventoried tanks at the receiving and regasification terminal, plus losses similar to those seen at the export terminal. The rate at which BOG is generated is dependent on a variety of parameters: in addition to the operating conditions, these include the design and construction of the storage tanks, the composition (density) of the LNG, and the voyage time.[142,143] The API has developed several Standards that apply to the LNG value chain.[144,145,146,147]

Recovery and reuse of BOG, rather than sending it to flare, carries a significant economic incentive. Many newer LNG facilities are subject to stringent environmental regulations that prevent routine flaring of BOG. A common approach is to compress it for use as fuel gas to run a gas turbine generator with a waste heat recovery unit to supply process heating. Excess BOG can be recondensed and recycled back to the inlet of the liquefaction trains for reprocessing so that no flaring is required during LNG carrier loading operations.

For existing facilities, adding a re-condenser, pre-cooler or BOG compressor, or the optimization of existing facilities to avoid flaring during LNG carrier unloading or reloading[149] are likely enhancement candidates. An engineering study is necessary to determine the economic options. Each LNG plant environment can differ in various ways, including jetty length, LNG storage capacity, loading rate and frequency, and available space for additional equipment. Similarly, plants can have different demands for fuel gas, desired product specifications and controllability issues, all of which affect BOG recovery strategies. Furthermore, since LNG loading/unloading are intermittent and unsteady processes, dynamic simulations are necessary to determine the rate of change of BOG generation, the effect of BOG recycling on plant performance and controllability, and system behaviors with respect to changes in different parameters.

Figure 21  Boil-off gas at LNG terminals[148]
Other options to reduce flaring at LNG facilities include the following:

- **Off-specification gas recycling**
  Gas pretreatment trains remove impurities (i.e. water, CO₂, heavy hydrocarbons, hydrogen sulfide and mercury) from the feed gas. During start-up, large quantities of off-specification gas are usually flared. Facilities should be available to recycle off-specification gas during and after start-up in a closed loop instead of flaring it.

- **Propane and refrigerant recovery**
  Before planned maintenance of compressors and other equipment, propane and mixed refrigerant should be removed from the system. Typically, these gases are flared. Good practice involves recovering propane and mixed refrigerant back to storage.

- **Primary dry-gas-seal vent recovery**
  Dry seals in refrigeration compressors prevent the process gas from migrating into the atmosphere but some of the sealing gas passes through the primary seal and is typically flared. A vent gas seal recovery system should be employed to send the recovered gas to the BOG system for compression and reuse.

- **Improving dry-out procedures**
  Typical practice has involved the use of natural gas to dry out equipment before LNG production can start. Substitution with nitrogen, wherever possible, will reduce 'dry-out' gas that is sent to flare.

- **Improve cool-down procedures**
  Typical start-up procedures include manually controlled pre-cooling with propane refrigerant followed by mixed refrigerant recirculation. The pre-cool-down step flares propane while final cool-down flares off-specification or warm LNG. New methods that eliminate the separate pre-cool-down step and use more sophisticated control of the mixed refrigerant and the feed can result in less flaring and faster, more consistent start-ups.

**ENHANCED FLARING MEASUREMENTS AND MONITORING**

Accurate measurement of the vented and flared volumes is important when evaluating the applicability and economics of capture technologies. The flare gas flow rates can vary widely from low levels during routine, continuous operation to relatively high levels during upset conditions. With such a variation in flow rates, taking accurate measurements over the possible range of flow can prove challenging. As previously discussed, flow meters have been the chosen technology to determine flare gas measurement. In recent years, major technological advancements have allowed for the introduction of new tools that can be utilized to accurately measure and detect vented and flared gas volumes. These technologies include the following:

- **Satellites** are able to map flares or methane emissions across large areas, and take measurements at specific locations. The VIIRS instruments onboard NOAA satellites were discussed on pages 33 and 57. Another example is MethaneSAT, a subsidiary of EDF (the Environmental Defense Fund), which will provide data to oil and gas companies and countries to help them to manage leaks and other releases. This technology is scheduled for deployment in space by 2022 and will be made available to the public free of charge. The technology works by using a spectrometer to measure a narrow part of the short wave infrared spectrum where light is absorbed by methane, detecting concentrations as low as two parts per billion. The high spatial resolution and a 200-kilometer view span is intended to allow the satellite to track smaller emission sources across large areas.

- **A thermal imaging device** is able to recognize the difference between the heat signature of a flare stack flame and the surrounding background (e.g. the sky or clouds). The camera’s spectral response and calibration allows it to see through moisture in the air to obtain a good quality image and a relative temperature reading of the flare stack or pilot flame. In addition to visual monitoring of the stack flame and smoke, this system has the ability to automatically control the ratio of assist gas to waste gas.
Drones can be equipped to identify methane using a laser and quantum sensor which can detect single particles of light. The high-resolution sensing enables the system to make high-precision, high-resolution measurements. For example, one particular drone on the market has a sensor that is able to detect methane from a distance of more than 50 meters and at a speed which will enable the production of a heat map of methane concentrations. A planned software development will enable the system to use the methane concentrations to develop images of plumes, such as from the incomplete combustion of flares, or from unit flares.[153]

Continuous emission monitoring systems (CEMS) are being utilized to provide real-time mass spectrometry suitable for flare monitoring. With flare streams usually comprised of a combination of waste gas from numerous plant processes, and with the composition steadily changing, CEMS provide the capability of determining the complete speciated composition of the flare gas stream. With this capability, facilities are able to detect which process unit plays a major role in the flare stream at a given time. These systems can also provide real-time Btu values, which helps to give a breakdown of the measured component concentrations in the gas stream.[154]

**RESEARCH AND DEVELOPMENT**

Many of the technology options for monetizing associated gas are derived from extensive experience with the use of pipeline quality dry natural gas. However, gas source location and quality can present unique challenges. The application of well-known separation and treatment unit operations, along with process optimization techniques, have addressed these challenges in many different situations, especially for large projects where the project economics have been favorable. The technology solutions listed in Box 4 are considered to be mature, with many commercial deployments.

**Box 4 Mature technologies for associated gas**

The following technology options for utilizing associated gas are considered to be mature, with many commercial deployments:

- Reinjection
- Compression and distribution to end use customers
- Large-scale power generation
- Small-scale power generation via portable internal combustion engine
- Small-scale power generation via micro-turbine
- Small-scale power generation via fuel cells
- CNG
- LNG
- NGLs
- GTL
- Ammonia
- GTL

A summary of associated gas utilization technologies is presented in Table 10 on page 68.

Developing technologies that can be incorporated into projects for the utilization of remote, low-flow and/or poor quality sources of associated gas represent an active area of research and development. Links to select, company-specific technology providers are shown in Table 11 on page 68.
## Section 2
Flaring management—a framework for the oil and gas industry

### Table 10 References for associated gas utilization technologies

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### Table 11 Developing technologies for associated gas utilization

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