Section 1

Flaring management—
an introduction

This introductory section provides core concepts and definitions, and puts the overall concept of flare management into context.
Flaring management—an introduction

Associated gas is the natural gas that is produced as a co-product with oil during oil extraction. Significant volumes of associated gas are flared annually at oil production sites around the globe, contributing to climate change by releasing CO₂ and CH₄ into the atmosphere. Much of this flaring occurs on a routine (typically, continuous) basis. Flaring also occurs because of events that are non-routine in nature and lead to an unanticipated interruption of natural gas extraction, processing, transportation and downstream (e.g. liquefaction) operations. Some flaring is also attributable to emergency or safety incidents. Flaring wastes a valuable energy resource that could provide energy to support economic growth in many locations around the world and help society make progress towards achieving the UN Sustainable Development Goals. However, flaring of natural gas is preferable to venting the gas without combustion in a flare (referred to as cold venting), because the release of methane is both a safety concern and a greater contributor to climate change.

Globally, many companies and countries have successfully reduced flaring from production operations. This makes good environmental and business sense. However, there is still a significant level of routine flaring of associated gas on a global basis, as shown in Figure 1 for the top 30 flaring countries.

Figure 1 Flare volumes for the top 30 flaring countries, 2016–2020 (sorted by flare volume)

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2 See Environmental and social aspects (the link with the Sustainable Development Goals) on page 26.
3 Uncombusted methane has a significantly higher global warming potential than the CO₂ created during combustion in a flare. Venting of associated gas contributes to climate change because the primary constituent of natural gas is CH₄, a potent GHG, with global warming impacts 28 times those of CO₂, if measured over a 100-year period based on the 5th Assessment Report of the UN Intergovernmental Panel on Climate Change—Climate Change 2013: The Physical Science Basis. Chapter 8; ‘Anthropogenic and Natural Radiative Forcing’, Table 8.7: https://www.ipcc.ch/site/assets/uploads/2018/02/WG1AR5_Chapter08_FINAL.pdf
It is estimated that global flaring decreased from 150 billion cubic meters (bcm) in 2019 to 142 bcm in 2020; this volume of flared gas is enough to power sub-Saharan Africa. If this amount of gas was used for power generation, it could provide about 750 billion kWh of electricity—more than the African continent’s current annual electricity consumption.

Significant barriers can impede progress in bringing flared natural gas to more effective use. Examples include a lack of infrastructure and/or the distance to market, capital constraints, gas ownership arrangements, and a lack of government project enablers, among other factors. However, gas flaring can be effectively mitigated when local operators and governments work together to overcome these barriers. This document addresses each of these barriers so that operators, owners, financiers and governments can proceed from a common understanding of the challenges that exist and the opportunities to be captured.

**FUNDAMENTALS OF GAS FLARING**

This section provides an overview of several important topics related to gas flaring, and includes a discussion of:

- the natural gas value chain (see Figure 2) and different reasons for flaring for different segments of the chain;
- monetization of associated gas from the perspective of the key participants and their respective roles in the decision processes;
- technology options for flare gas reduction and the market factors that should be considered for any project; and
- categorizing associated gas projects, including economic and technical drivers as well as environmental and social aspects.

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4 Based on an average heat rate of 7.35 MMBtu/MWh for gas-fired combined cycle generators, as reported to the US Energy Information Administration (2015 data, https://www.eia.gov/electricity/data/eia923), and an assumed natural gas heating value of 1,036 Btu/cubic foot.
Essential elements of associated gas and flare gas

Natural gas value chain

To consider the potential opportunities for better utilization of associated natural gas, it is important to understand how natural gas moves from the well head to the customer. Figure 2 on page 11 illustrates the flow of gas along the value chain in those operations, from the oil or gas well head through gas processing, transportation, liquefaction or conversion of natural gas to fuels, chemicals or other derivative products, and end use.

Beyond the logical left to right product movement, there are several attributes to consider:

- Often, the owner of the hydrocarbon resource is a separate party from the operator that explores for, and produces, that resource (see Monetization of the associated gas value chain on page 16).
- Due to the inherent price differential between hydrocarbon liquids and gases — even on an equivalent energy basis — the resource owner and the operator can (and often do) place priority on the crude oil produced versus the co-produced associated gas.
- Intermediaries in the middle section of the value chain, from the inlet separator to the gas processing plant and the final customer distribution network, add value through processing, upgrading, moving and distributing the natural gas or derivative products. Generally, the facilities and infrastructure in this ‘midstream’ section of the value chain tend to be capital intensive, capacity-limited and fixed in place.
- Except for agreements between end-use customers and local distribution companies (LDCs), commercial arrangements between parties are often long-lived and involve sophisticated provisions to deal with downside risk mitigation related to certainty of supply and fluctuations in commodity prices.
- For all customers, but especially for the industrial and electric utility plants and the exporters, there are no convenient, cost-effective substitutes for natural gas as an energy carrier, once a commitment to facilities and equipment that rely upon it has been made.
- There is often substantial government intervention through regulations, taxes and subsidies, land access and, in certain jurisdictions, involvement in contracts. These government actions can either incentivize or disincentivize the mitigation of gas flaring (refer to Section 3).

Each of these factors can, depending on the particular local conditions that exist, play an important and determinative role in defining the possible options for monetizing associated gas. In upstream operations, a range of factors may influence the potential to flare gas, from infrastructure limitations for associated gas operations to equipment reliability issues for non-associated gas operations. In associated gas operations, onshore operators typically allow for better matching of incremental capacity with production growth due to the relative ease of adding additional processing facilities.[4] Offshore, the process occurs in larger steps due to the significant logistical, construction and safety risk management challenges that exist. In either case, because the rates of associated gas production may not be well characterized prior to the start of operations, the development of gas handling infrastructure can lag, be capacity-limiting, or be financially unattractive. Further, some associated gas operations with low gas-to-oil ratios (GORs) have the added challenge of finding economically viable solutions to address low volumes of gas produced.

The recent growth in production from onshore tight oilfields/shale oil reservoirs, where horizontal drilling and hydraulic fracturing are employed, presents a special challenge with respect to the management of associated gas. Refer to Unconventional and shale operations on page 37 for more details.

In non-associated gas production, where production is focused on the natural gas product stream, a different set of challenges may exist which can lead to gas flaring. These challenges can include operational upsets, such as overpressure of equipment or pipelines, equipment shutdown or failures, and downstream capacity limitations, such as a processing plant shutdown. While these tend to be non-routine, i.e. they are temporary and non-continuous events, they can lead to large volumes of transient flaring. These same challenges may exist across the other segments of the natural gas value chain downstream of the production stage, including gas processing, transmission, downstream derivative production (e.g. liquefied natural gas (LNG) and compressed natural gas (CNG)), and end use.
However, sometimes the market value does not support a positive return on the investment needed to bring the associated gas from the producing field to a value-added consumptive use. In such cases, and even after considering the societal benefits of utilizing associated gas, routine flaring is often the outcome. While market value is a key driver, there are other key reasons why associated gas flaring occurs, as shown in Table 1.\[5,6,7,8,9,10\]

**Why is gas flared?**

Flaring can occur for many reasons, ranging from technical issues (e.g. initial start-up testing of a facility, unplanned equipment malfunctions, etc.) to market factors (e.g. insufficient demand, low gas prices, etc.). As a primary energy source in a world of consistently growing energy demand, associated gas has intrinsic value. Whether as pipeline-quality natural gas or some other derivative product, the market value of associated gas depends on a number of factors that arise along the value chain between the producer and the consumer.

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### Why is gas flared?

**Table 1 Why is gas flared?**

<table>
<thead>
<tr>
<th>ROOT CAUSE</th>
<th>EXAMPLES OF WHY FLARING OCCURS</th>
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</table>
| Market access constraints | - Distance from the production field to markets can limit the options for monetizing associated gas, making it economically infeasible to treat, pressurize, transport and distribute commercial quality gas, or to construct electricity power generation and transmission facilities.  
- Obtaining access for long-distance transmission pipelines can involve long lead times and represent significant project risk due to landowner legal challenges and/or government permitting processes.  
- In cases where the field producing the associated gas is close to a local market, the market may be too small to support development of a gas processing and distribution infrastructure.  
- In some countries, associated gas is flared due to the structure of markets that limit new investments or the right to use existing infrastructure.  
- Where existing gas processing and transmission infrastructure exists, the system may be at capacity, have unreliable equipment (e.g. compressors), or be subject to contractual limits that place new supplies of associated gas at an economic or other disadvantage.  
- Third-party infrastructure failures may occur (e.g. due to unstable national grid or domestic gas infrastructures).  
- For some short-cycle operations, such as shale oil produced through horizontal drilling and hydraulic fracturing, production can exhibit substantial variability due to high initial production rates followed by steep declines. This limits the economic sizing of downstream gas handling facilities to manage peak production.  
- Typically, oil producers favor investments in additional liquids production over those projects that could monetize associated gas due to the higher returns that can be generated from incremental oil production. This can limit the pool of capital that is available to associated gas utilization projects.  

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\(continued...\)
Various analyses of the issue of how to monetize associated gas have identified a number of these factors which lead companies to a decision to flare.

Considered together, these challenges suggest that there is a fundamental failure of the market to align the full volume of associated gas with the world’s aggregate demand for energy. Although any decision made by a company to flare associated gas to maintain liquids production reflects a value-adding outcome of a company-level optimization decision-making process, the sum of all such decisions results in a suboptimal outcome for society as a whole. This outcome — the intentional and persistent wastage, via routine flaring, of associated gas — creates an economic ‘opportunity cost’ consisting of lost energy resources and the generation of GHG and other emissions.

**How is flaring categorized?**

The GGFR partnership has developed a set of definitions for gas flaring, which are summarized in Table 2 on page 15. As shown, routine flaring, which can be continuous or intermittent, occurs during normal oil production operations when there are insufficient infrastructure, facilities or amenable geology to reinject the associated produced gas, utilize it on-site, or send it to a market. Safety flaring covers all situations where a flaring is used to maintain the safe operation of oil and gas production facilities. Non-routine flaring is all flaring other than routine and safety flaring, which can be scheduled/planned, such as a maintenance turnaround event, or unscheduled/unplanned, such as equipment failure. Distinguishing safety and non-routine flaring from routine flaring is critical to reducing overall flaring volumes as, globally, a large fraction of the flaring occurs because of economic conditions and choices, not for safety reasons.
### Table 2: Flaring categories as defined by the GGFR[^1]

<table>
<thead>
<tr>
<th>CATEGORY</th>
<th>DEFINITION</th>
<th>EXAMPLES OF FLARING</th>
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| Routine      | Routine flaring of gas at oil production facilities is flaring that takes place during normal oil production operations in the absence of sufficient facilities or amenable geology to allow the produced gas to be reinjected, utilized on-site or dispatched to a market. Routine flaring does not include safety flaring, even when it is continuous. | - Flaring from oil/gas separators  
- Flaring of gas production that exceeds existing gas infrastructure capacity  
- Flaring from process units such as oil storage tanks, tail gas treatment units, glycol dehydration facilities and produced water treatment facilities, except where required for safety reasons |
| Safety       | Safety flaring of gas is flaring carried out to ensure the safe operation of the facility.                                                                                                                                 | - Gas stemming from an accident or incident that jeopardizes the safe operation of the facility  
- Blow-down gas following emergency shutdown to prevent over-pressurization of all or part of the process system  
- Gas required to maintain the flare system in a safe and ready condition (purge gas/make-up gas/fuel gas)  
- Gas required for a flare’s pilot flame  
- Gas produced as a result of specific safety-related operations, such as safety testing, leak testing or emergency shutdown testing  
- Gas containing H₂S, including the volume of gas added to ensure good dispersion and combustion  
- Gas containing high levels of volatile organic compounds other than methane |
| Non-routine  | Non-routine flaring of gas is all flaring other than routine and safety flaring.                                                                                                                                 | - Temporary (partial) failure of equipment that handles the gas during normal operations, until the failed equipment is repaired or replaced; examples include failure of compressors, pipeline, instrumentation, controls, etc.  
- Temporary failure of a customer’s facilities that prevents receipt of the gas  
- Initial plant/field startup before the process reaches steady operating conditions and/or before gas compressors are commissioned  
- Start-up following facility shutdowns  
- Scheduled preventive maintenance and inspections  
- Construction activities, such as tie-ins, a change of operating conditions, plant design modifications  
- Process upsets when process parameters fall outside the allowable operating or design limits and flaring is required to stabilize the process  
- Reservoir or well maintenance activities such as acidification, wireline interventions  
- Exploration, appraisal or production well testing or clean-up following drilling or well workover |
The category descriptions and examples in Table 2 provide a consistent framework for analysis and will be used throughout this document. Regardless of how flaring is regulated, administered or controlled by government authorities, all flared gas scenarios are covered by these three definitions. There is no fourth definition that addresses government-approved flaring. Instead, determining how flaring operations align with compliance requirements established in local law and regulation is a separate question for the upstream operator to consider.

Monetization of the associated gas value chain

In a well-functioning market, associated gas would be valued on an energy-equivalent basis with other energy sources (e.g. the natural gas price indexed to crude oil price). Producers would find valuable uses within their own operations, or for-profit companies would provide facilities and services to capture the gas energy and deliver it to satisfy customers’ demand. This process would function because each participant along the value chain would recognize revenues in excess of the marginal cost of their products and services.

The fact that the amount of gas flared has not declined substantially over the past ten years[12] indicates that markets are not always well-functioning. Instead, there are any number of factors that can (and do) distort valuations, sometimes enough to depress returns to levels that make economic justification of gas monetization difficult, in the absence of subsidies, carbon taxes, government policies or other incentives. Of those factors, a low gas price (whether because of excess supply or some form of price control) is the most difficult to overcome. When gas prices are robust, other opportunities to utilize the gas are incentivized. Despite the challenges that lead to flaring, operators and other stakeholders can recognize benefits from utilizing associated gas, even if the projects do not generate a return that meets the company economic thresholds. Some examples of benefits include:

- improved reliability by using gas to generate electricity on-site, avoiding curtailments during periods of grid stress (e.g. renewable drop-offs, high summertime demand) or transmission line shutdowns due to natural disasters (e.g. wildfires, wind events);
- avoiding shut-ins caused by flaring above authorized amounts when downstream gas off-takers experience extended malfunctions or shutdowns;
- building company reputation or satisfying investor or other stakeholder expectations by demonstrating actions to reduce GHG emissions or achieve self-imposed goals, such as a commitment to the ‘Zero Routine Flaring by 2030’ initiative[13];
- enhancing the attributes of a product, such as a ‘low-carbon’ crude or natural gas[14] by minimizing the GHG footprint of the production operations;
- diversifying product offerings by generating electricity, manufacturing gas-derived liquids for sale or producing LNG in small quantities; and
- creating a commercial advantage, such as preferred bidder status on other energy sector projects sponsored by a host government.

The gas value chain schematic (Figure 2, page 11) shows that there are a number of key participants with influential roles in the decision processes that can determine whether associated gas is monetized rather than flared. These are discussed below.

**Resource owner**

Resource owners can be individuals, partnerships, companies, other private parties and governments (including, national oil companies[5]). Many resources are developed with multiple venture partners, and various equity and contractual arrangements. The nature of these arrangements may play a key role in how the resource is developed, and how partners view and influence investing in flare minimization.

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5 Typically, national oil companies operate through production-sharing contracts, with the government retaining ownership of the hydrocarbon resources.
In almost every instance, a resource owner desires to realize royalty or other income from the production of the hydrocarbons in which it retains an ownership interest as quickly as possible. This desire is modulated by contracts, which typically provide that a lease or concession is granted to an oil or gas producer. The arrangement remains in place, with the production company controlling reservoir development as long as the owner derives royalty or sales income within a specified period. While outside the scope of this document, the type of contract in place can disincentivize gas monetization and lead to flaring. Therefore, effective and informed contract negotiation with partners and government entities is an important element in addressing the flaring of associated gas.

For the case where the resource owner is a government entity or national oil company (NOC) versus a private party (individual or company), the decision-making calculus can be different. A government/NOC owner has other factors to consider besides near-term profit maximization, such as national energy sector strategy goals, foreign relations, relationships with private parties operating within the country’s energy sector, domestic policy goals, etc. These considerations can take precedence over traditional oil and gas decision criteria. Additionally, where there is a high degree of coordination between government energy, finance, environmental, and tax departments, outcomes may not be the same as when a private party is subject to the independent oversight of such authorities.

Production operator

The production operator is typically either the resource owner or an equity partner in the venture. Key challenges may arise where the contractual arrangement between the resource owner and production operator does not incentivize flaring minimization in order to stay profitable or cash flow positive in the venture. For example, production quotas for oil, and/or capital constraints, may disincentivize investments in capture, processing or conversion, and transmission and distribution facilities, which would otherwise create value by utilizing the associated gas. In cases where the production operator is the resource owner, such investment decisions are predicated upon the alignment of several factors (i.e. market demand, gas price, gas take-away infrastructure, etc.), many of which are outside the scope of the producer’s control. Offshore production has additional challenges associated with the interconnectedness of offshore production facilities with multiple operators. As previously stated, economics may favor the production of oil along with the flaring of the associated gas or its reinjection to facilitate that production. Due to the low prices of natural gas liquids (NGLs) and natural gas, particularly in the Permian Basin in the southwestern part of the United States, 87% of revenues come from crude oil, with only 10% from NGLs and 3% from natural gas.

The pressure on companies to deliver growth in liquids production and reserves can even lead to a weakening in a company’s financial metrics. For example, in 2014–2018, the oil market encouraged upstream companies to look for the most expedient route to deliver more crude production. Because many government jurisdictions were supportive of growing crude oil production (due to increasing jobs, taxes, royalty revenue, etc.), a substantial quantity of associated gas was flared.
Government authority/regulator

Government entities play a significant role in the gas value chain. Their actions have an influence in four key areas: upstream oil and gas legislation/regulation; commercial law and contractual practices; fiscal framework (e.g. royalties, taxes, subsidies and other financial incentives and penalties); and environmental and safety regulation (see Figure 3). For a description of the lessons learned from effective government policies and programs see Section 3 of this guidance.

Midstream entities

The midstream segment consists of gathering, processing, and transportation facilities and services that connect upstream wells to downstream customers, converting a raw energy source to commercial product(s) to satisfy a demand. In some cases, the parties that operate in this segment are separate entities from the upstream production companies and the downstream customers. For those cases where the midstream segment is controlled by a government or state-run enterprise, or is specified in a concession agreement, commercial factors can play a minor role in the decision process for the management of associated gas. Offshore, the ownership situation is project-specific. In some cases, the model resembles the onshore situation with independent third parties operating in the space. In other cases, the facilities are determined by the terms of the concession agreement with the host government.

Where the commercial environment for the midstream segment relies on separate entities that engage in arm’s-length commercial transactions with upstream producers, monetization of associated gas occurs through the addition of processing and transmission capacity that meet the company’s financial return targets. Suppliers of gas and midstream entities negotiate terms that reflect positive outcomes for both parties. However, past data\[19\] suggest that midstream capacity additions often trail the growth of associated gas production due to limited competition, large initial investment requirements and, in the case of pipelines, the requirement for landowner access and regulatory approvals, as well as fluctuating market conditions or reliability of infrastructure. Processing and pipeline capacity limitations, even if temporary, can lead to flaring in the upstream operations.
Typically, additions of midstream gas processing facilities are made in combination with additions to gas transmission pipeline capacity, to ensure that both product streams (NGLs and pipeline quality gas) have market outlets. However, there could be a scenario (albeit less likely) where the demand for NGLs drives the construction and use of the separation facilities ahead of gas take-away capacity, in which case the gas could be flared. The quantity of associated gas flared routinely is usually a result of the gap between midstream capacity and the supply of associated gas.[19]

**Sellers of natural gas products**

Depending on the geography and/or investor base, entities that market fuels (including gasoline, natural gas, LNG, etc.) represent an emerging stakeholder group that can have an indirect influence on the disposition of associated gas. This arises from customer expectations, industry standards and possible regulation regarding the carbon footprint of fuels. As societal initiatives to limit GHG emissions grow, consumers, environmental groups and local community groups are using data that links flaring for individual oilfields to final products[20][21][22] to put pressure on suppliers to minimize the footprint of the fuels that they supply.[23] The same information is being used to drive regulations,[24][25] to accomplish the same. From a market incentive perspective, an emerging trend towards carbon-neutral products, such as net-zero LNG, is expected to have a positive influence on incentivizing reductions in associated gas flaring.

**Flare gas-to-market options and principles**

A number of options for monetizing associated gas to reduce routine flaring are available in the market, as shown in Figures 4 and 5 for onshore and offshore operations, respectively.

**Figure 4  Examples of onshore options to monetize associated gas**[26]
Section 1
Flaring management — an introduction

As shown in the Figures, the most common approaches used to capture and monetize associated gas include the following:

- **Own consumption:** generating electricity or heat for on-lease usage
  
  Using associated gas as a field fuel source is common practice as it is typically the lowest-cost alternative for providing power to operations, and can facilitate operations in remote or difficult-to-reach locations that lack a grid connection or natural gas pipeline. A variety of vendors have developed technologies for local electrical power generation, including reciprocating engines and gas turbines that can handle the compositional variability that is common in associated gas streams. This option will have limited impact in cases where there are large volumes of associated gas.

- **Gas reinjection:** reinjecting gas into the reservoir to enhance liquids recovery
  
  Gas reinjection into a crude oil reservoir is a common technique used to increase pressure within the reservoir and improve oil production. In the case of tight oil developments, reinjecting gas into the same reservoir has not yet been demonstrated as being technically and economically feasible on a broad scale, although some work suggests that it is beneficial.

Figure 5 Examples of offshore options to monetize associated gas

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[28, 29, 30, 31, 32, 33]
Gas gathering system: installing gas gathering and compression (and NGL separation) facilities to feed a pipeline-quality natural gas network

Typically, the export of associated gas via existing gas pipelines (after treatment to remove impurities or contaminants) is the base case, least-cost option for monetization. However, if the gas stream also contains NGLs, it will need to be pretreated to produce a dry gas with a heating value that meets the sales gas specification. The value of recovered NGLs can help to justify a gas monetization project if existing NGL processing capacity exists. If capacity in an existing NGL recovery plant is not available, the cost can be significant. The design of an NGL recovery plant is complex, driven by the feed gas composition, flow rate, location and available utilities, among other factors.

CNG: producing compressed natural gas and transporting it to customers

CNG, which is methane stored at high pressure, is typically used as a substitute for gasoline in motorized vehicles. At a well pad, technology can be installed to produce the CNG, which can then be transported by truck over relatively short distances for use as a fuel for oilfield activities, or to a central point where the gas can be put into a pipeline system. CNG requires treatment, including dehydration of the gas and, if applicable, removal of NGLs. For large volumes of associated gas, a regional distribution network and refueling stations (along with a fleet of CNG vehicles) would be needed to support the investment in infrastructure for this product. Studies conducted for the GGFR show that onshore CNG transportation could be financially viable for volumes of up to 5 million standard cubic feet (scf) per day.[35]

LNG: converting gas to liquefied natural gas (micro-scale or world-class export)

The typical scheme for monetizing associated gas via LNG requires facilities for gas collection, treatment, liquefaction, transport and regasification. World-class LNG projects, which can consume large volumes of associated gas, are highly capital-intensive and require close coordination among partners and prompt extensive government agency oversight, and involve many stakeholders. New technologies are making LNG production possible on a micro scale — at the field or well pad level (see Box 1) — where it can be produced and then transported to markets.

Gas to liquids, gas to chemicals: converting gas to other products

Conversion of associated gas to other products, such as gas to liquids (GTL) or gas to chemicals (GTC), relies on separation or other unit operations to create synthetic fuels or other high-value products (e.g. olefins, fertilizers, acids) from associated gas. Depending on the technology chosen, some processes, such as gas to methanol, are able to operate with rich gas feed, with less stringent constraints for gas pretreatment. Processes to convert natural gas to hydrogen, via steam methane reforming or other novel technologies, coupled with carbon capture and sequestration, are part of another emerging area of research into the use of methane resources.[37] Originally, GTL and GTC projects were typically large-scale, energy- and capital-intensive installations that required significant volumes of gas to be economical. Successful projects depended on a robust market demand and low gas price for the products produced. Beginning in 2010, smaller-scale systems (from 25 million scf/day down to 0.5 million scf/day) have been developed. Modularization, process intensification and the acceptance of slightly lower process efficiencies have contributed to GTL units becoming a viable option for the monetization of flare gas.
Gas to wire: installing grid-scale electricity generation facilities
A sufficiently large supply of associated gas can form the basis for a gas-to-wire (GTW) project, which includes electricity generation and transmission for the purpose of selling power to the grid. Typically, GTW projects consume large volumes of associated gas, are capital-intensive, require close coordination among partners, prompt extensive government agency oversight and involve many stakeholders.

Gas to data centers: utilizing gas to power portable data centers
Other emerging flare gas utilization applications are being introduced to the market, such as converting the gas to electricity to power a portable data center. A number of similar flare mitigation applications are being utilized in US oilfields.

To select the best method for flared gas recovery and reduction, operators will need to have a good understanding of how the flared gas is produced, its quality, and the possible options for utilization. Many factors, as alluded to above, will influence the technical and economic feasibility of alternatives to monetize associated gas. In 2020 the GGFR published a document entitled GGFR Technology Overview – Utilization of Small-Scale Associated Gas that provides details of the technical applicability of different technologies for the small-scale utilization of flared associated gas. Ultimately, the key question is which technology option offers the highest return over the project life when considered against market fluctuations, trade barriers, political changes, technical advances, etc.

In addition to minimizing flaring, addressing venting of associated gas is important to minimize methane emissions. However, vented gas volumes tend to be much lower than flared volumes, thus limiting the applicable associated gas utilization options. Installing a vapor recovery unit (VRU) and utilizing the gas as fuel gas or sales gas is a preferred approach to reducing methane emissions, where possible. Other technologies for reducing methane emissions from venting are readily available, and tend to be more specific (e.g., instrument air-driven pneumatics, replacing high-bleed pneumatic controllers with low-bleed controllers, leak detection and repair (LDAR) programs to reduce fugitive leaks, etc.). Flaring is preferred over venting to the atmosphere from both a safety and GHG perspective, as the methane and overall CO₂ equivalent (CO₂e) emissions are lower from flaring compared to venting.

Economic and technical considerations for flare gas reduction projects
The evaluation of gas monetization options is a multidimensional issue requiring a systematic approach to selecting the optimal option. There are many operational and technical considerations that must be weighed during the evaluation of possible gas utilization options. In addition to technical and environmental (e.g. GHG emissions avoided) considerations, commercial and logistical issues as well as market conditions play a key role in the evaluation process. The expected volumes of gas to be recovered, the distance to market, and the selling price of the gas (or gas-derived) product are among the most important financially-driven variables. There are a host of factors that have an impact on the selection of approaches and technologies. Upstream and downstream factors influence the selection of midstream processes and operating flexibility. The larger the project, the more complex the interrelationships and the need for collaborative solutions across multiple stakeholders.

The key technical and economic considerations for flare gas reduction projects are summarized in Table 3 and described on the following pages.

Table 3  Key technical and economic considerations for flare gas reduction projects

<table>
<thead>
<tr>
<th>ASPECT</th>
<th>KEY CONSIDERATIONS</th>
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<tbody>
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<td>Technical</td>
<td>● Gas volume and forecast over the life of the project</td>
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<td></td>
<td>● Gas composition and pretreatment requirements</td>
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<td></td>
<td>● Gas pressure characteristics</td>
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<tr>
<td>Economic</td>
<td>● Distance to the market</td>
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<td></td>
<td>● Access to infrastructure</td>
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<td></td>
<td>● Project costs and other factors driving economics</td>
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<td></td>
<td>● Market demand</td>
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<tr>
<td></td>
<td>● Contractual and financing arrangements</td>
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<td></td>
<td>● Netback price</td>
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</table>
**Gas volume and forecast over the life of the project**

The gas production volume profile reflects the cumulative effect of the natural decline in output from producing wells balanced by development plans to maintain or grow production in the field. The projected available volume has a strong influence on the types of gas utilization projects that are likely to be economical (see Associated gas forecasts on page 30). However, even after determining the preferred project alternative, uncertainty of how the production rate from the field will change over time presents a challenge for system and equipment sizing. Designs based on initial rates or long-term average production volume can have significant cost and flaring rate implications. To address the capacity challenge for certain types of projects, the system capacities can be adjusted to match the production profile by leasing equipment as volumes change or, preferably, in many cases employing small-scale modular installation solutions. This can mitigate the excess upfront capital costs associated with installing equipment that is oversized. Onshore operations are more amenable to this strategy than offshore installations.

Figure 6 presents the various gas utilization options that are applicable by project scale, in terms of associated gas flare volume in bcm per year. The indicative associated gas volume ranges are < 0.1 bcm/year, 0.1–0.5 bcm/year and > 0.5 bcm/year for small-, medium- and large-scale projects, respectively.

**Gas composition and pretreatment requirements**

The composition of associated gas from wells can vary over time due to reservoir behavior, declining well production, recovery techniques and operating conditions. If the associated gas stream is a composite that comes from many sources, there can be substantial variations in gas composition and impurities as new wells come online or as other wells or production facilities are taken offline for maintenance. The changing composition of the gas makes it more challenging to design suitable facilities than it is for dry natural gas. All types of facilities are affected by compositional variability, and provisions to account for this variability should be considered. The gas throughput of gathering systems and pipelines can be reduced if liquid condensation occurs. Gas plants producing NGLs have unit operations that are designed based on expected ranges of C₂–C₅ and heavier hydrocarbons. Depending on the quality of the raw gas source, CNG and LNG facilities often require pretreatment to remove certain components, particularly contaminants such as CO₂ and hydrogen sulfide (H₂S). Gas-to-power units (especially in-field units) may also require some form of gas conditioning for stable turbine or engine operation. Gas-to-methanol processes and gas-to-liquids via the Fischer-Tropsch process, on the other hand, have the advantage of being able to operate with rich gas feed, without the need for gas pretreatment.
Gas pressure characteristics

Gas pressure is a significant factor. A gas stream at a steady, elevated pressure is preferred, due to the reduced costs required for treatment and compression. For fields where gas pressure is variable (due to reservoir conditions or production operations), the operation of gas gathering systems can be difficult. This is especially true for shale oil developments, where aggressive infield drilling creates a string of new, high-pressure and high-volume wells. This can create pressure and flow surges that enter into a gathering system, which can completely consume system capacity and ‘crowd out’ older low-pressure wells, forcing gas flaring.

Distance to the market

Geographical factors can determine the feasible options for associated gas utilization. Because natural gas is relatively low in energy content per unit volume, it is relatively expensive to transport, which represents a key obstacle to the increased use of gas. Pipelines are the most economical way to move gas from the source to the market for onshore and near-shore gas. However, as transportation distances increase, securing right-of-way access can become challenging, and if transportation routes require crossing significant bodies of water, pipelines become less economical. Furthermore, pipelines can become a stranded asset if associated gas volumes decrease over time. CNG or mini-LNG solutions acting as ‘virtual pipelines’ can be alternatives, for distances up to ~1000 km, that offer gas feed flexibility. Consequently, the closer a well or field is to gas gathering networks, the more options the production operator has. Long distances, whether for the transportation of gas via pipelines, or the transmission of electricity to the customer or export markets, can strain the economic case for any project. For larger developments or multiple operators involving multiple wells, the impacts can be less severe, as more utilization options become economical due to economies of scale (i.e. larger gas production volumes). Figure 7 illustrates the dependency on the distance to the market for each technology type.

Access to infrastructure

Processing infrastructure and take-away capacity are often identified as major critical path items that need to be addressed for productive use of associated gas.\(^{[43,44,45]}\) In addition, infrastructure can be a particularly sensitive stakeholder issue when large facilities (electricity generation, gas plants, pipelines or LNG plants) are needed. Land access, community impact assessments and public safety matters can prolong public consultation prior to agency authorization or permitting processes.

Project costs and revenues

The following project-related cost and revenue factors drive the economics of a flaring reduction project: \(^{[46]}\)

- Lease/concession terms that may control the utilization of associated gas or establish a separate royalty or payment tier for its use.
- The price of pipeline quality natural gas and price risk for the products produced, whether due to supply/demand market fluctuations, price controls, or tariffs imposed by government agencies.
- The cost of the gathering lines, compression equipment and other facilities, depending on the utilization scheme being employed.
- The size of the capital investment required, the production operator’s cost of capital, and the operator’s willingness to deploy capital in the face of other investment opportunities within its portfolio.
If external financing is used for the project, the terms can weigh heavily on profitability and can introduce new forms of risk with which operators may not be familiar.

- Additional operating, processing or conversion costs associated with the monetization project.
- The cost of acquiring and maintaining land or rights-of-way for gas (or electricity) transmission.
- The potential technological risk of a given approach can be a significant consideration depending on the size of the upfront capital investment and the expected payback horizon — the longer the time frame, the greater the risk of technological obsolescence (or uncompetitive cost structures).
- The implications of regulatory oversight and schedule risk imposed by the involvement of natural resources agencies, health and safety ministries, environmental protection departments, public utility commissions, or other government entities that may be involved (such as in the case of large LNG export projects).
- Fiscal issues, including taxes and royalties, plus any unique terms that may be imposed by a host government or NOC.
- Market dynamics and competition can be significant factors when pursuing GTL or GTC projects due to the specialized nature of the products and (potentially) the limited customer base for any particular product.
- In countries with economies in transition, additional considerations may include limited access to information and specialized contractor resources needed to complete the front-end engineering assessment. There can be difficulties in the local political context and cultural differences that require more planning and longer response times. In addition, local companies and partners may be hesitant to engage, or may lack the organizational capacity to fulfill commitments.

**Market demand**

In cases where the utilization of associated gas lies beyond the lease or concession, production operators seeking to monetize the gas resource rely on market indicators to determine whether there is sufficient demand for the produced volumes. The nearer (in terms of the value chain) the customers are to the producer, the easier it is for the producer to calibrate the market size and the likelihood for future growth. Longer chains involving multiple parties can attenuate the market signal(s), but nonetheless remain practicable options. However, there is the potential for commercial hurdles and, with each intermediary, a reduction in profit opportunity for the producer.

**Contractual and financing options**

Ultimately, the economic viability of any particular gas utilization approach depends on the nature of the contractual agreements between the production operator its partners/midstream off-takers, and the end user. ‘Take-or-pay’ or ‘deliver-or-pay’ contract terms are typical provisions in contractual agreements, and are often subject to much negotiation. Imposition of significant monetary penalties to fulfill such provisions drives the use of sophisticated risk mitigation strategies. Several different business models are available to manage financial commitments and allocate business risks among parties, such as a fee for services, shared equity (e.g. joint venture), or third-party funding of a new gas-monetizing entity.

**Netback price**

The producer of the associated gas will likely choose from among the available commercial alternatives based on the netback price for natural gas. The netback price is defined as a pricing assessment or formula based on the effective price to the producer/seller at a specific location or defined point. It will depend on: the likely product price in the target market compared with the energy equivalent of traditional fuel in use (e.g. diesel for power); the location of the market, transportation routes and related costs (tariffs, tax etc.); electricity import/export tariffs; product losses through transportation; and other risks and issues. For example, LNG netback prices may be determined by the market price of natural gas at market destinations less the cost of the pipeline transportation, regasification, shipping and liquefaction.

The sections on **Technology and economic assessment** (page 51), and **Economic and technical risk assessment** (page 60) provide more details for assessing the technical and economic risks associated with routine and non-routine flare gas monetization projects, respectively.
ENVIRONMENTAL AND SOCIAL ASPECTS (THE LINK WITH THE UN SUSTAINABLE DEVELOPMENT GOALS)

In September 2015, the United Nations General Assembly adopted the 2030 Agenda for Sustainable Development, including the 17 Sustainable Development Goals (SDGs) that aim to address some of the world’s pressing economic, social and environmental challenges (Figure 8). UN member states are expected to use the SDGs to frame their development agendas, and there is a recognition that the private sector will play an important role in achieving them.

The oil and gas industry’s operations and products intersect with a range of areas covered by the SDGs, including communities, ecosystems and economies. In 2017, IPIECA, the United Nations Development Programme (UNDP) and the International Finance Corporation (IFC) developed a shared understanding of the implications of the SDGs for the oil and gas industry and how the industry can most effectively contribute in the joint IPIECA/IFC/UNDP Mapping the oil and gas industry to the Sustainable Development Goals: an atlas. [50]

In 2021, IPIECA, with the World Business Council for Sustainable Development, launched Accelerating action: an SDG Roadmap for the oil and gas sector [51] (the Roadmap). The Roadmap aims to prioritize areas where the sector can significantly contribute to SDG progress by identifying key impact opportunities for the most material SDG goals and targets, coordinating effort across the entire industry. The Roadmap includes specific actions on flaring.

The oil and gas industry contributes to sustainable development in a number of ways. These include: generating direct and indirect jobs;[6] supplying access to energy that enables economic activity and social development; contributing substantial tax and other types of revenue to governments; enabling the development of advanced technologies and products through investment in research and development; encouraging local content and entrepreneurship with associated capacity building benefits; investing in the long-term social and economic success of the communities in which the industry operates; and managing the impacts of its operations by emphasizing environmental protection, health and safety, and human rights. The SDGs also highlight sustainability challenges for the industry, where more can be done to mitigate the adverse impacts of oil and gas development, for example the industry’s environmental footprint, including climate change and its associated impacts on communities.

Several SDGs and associated UN targets are particularly relevant in terms of the efforts needed to reduce and eliminate the flaring of associated gas. Details can be found in Annex I and in the joint publications mentioned above.

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6 Referred to as ‘Country Benefit Analysis’ based on GDP, fiscal parameters, capex and other parameters used to calculate the induced jobs generated either during the construction period and during normal plant operation at steady state.
GLOBAL INITIATIVES

The perception of associated gas flaring has evolved. Once viewed as an operational solution to a site-specific problem of how to deal with an unwanted by-product of oil production, it is now recognized as an undesirable activity with global GHG impacts. Upstream operators, governments, financial institutions, non-governmental organizations (NGOs) and technology providers have undertaken initiatives aimed at raising awareness and facilitating beneficial use of associated gas, with a goal of reducing the quantity of associated gas that is flared.

Global Gas Flaring Reduction (GGFR) partnership

The World Bank’s GGFR is a multi-donor trust fund composed of governments, oil companies and multilateral organizations working to end routine gas flaring at oil production sites across the world. An integral part of the GGFR’s strategy is the pursuit of shared prosperity with an aim towards ending poverty via a sustainable energy path and the wise use of natural gas resources.[53] The Partnership helps to identify solutions to the many technical and regulatory barriers to flaring reduction by developing country-specific flaring reduction programs, conducting research, sharing best practices, raising awareness, increasing the global commitments to end routine flaring, and advancing flaring measurements and reporting. The GGFR works in a range of oil-producing countries including Ecuador, Egypt, Gabon, Indonesia, Iraq, Kazakhstan, Mexico, Nigeria, Russia and Senegal.

The GGFR’s strategy is to support and assist governments as they develop policies and regulations that treat associated gas as an asset rather than an unwanted by-product of oil production. The partnership is now focusing more intently on helping governments to develop the institutional capacity and legal, regulatory, investment and operating environments to enable the utilization of associated gas. This will provide companies with the confidence and incentive to invest in flaring reduction projects. In some instances, this also means working with governments to develop the fundamentals, such as proper flare measurement practices, before the new policies and regulatory measures are developed. The GGFR prioritizes assistance to developing countries with high levels of routine gas flaring and low levels of energy access amongst its citizens, and those countries facing fragility, conflict and violence.

The GGFR regularly publishes estimates of global gas flaring from satellite data.[54] These data reveal that roughly 142 bcm of associated gas is flared each year, releasing about 400 million tonnes of CO₂ emissions, while wasting enough natural gas to power Sub-Saharan Africa. The gas flaring estimates are based on data from a satellite launched in 2012 which detects the heat emitted by gas flares as infrared emissions at global upstream oil and gas facilities. The GGFR also conducts periodic technical studies,[55] and technology and service provider overviews, to assess the technical feasibility and economic viability of using flared gas for rural electrification or commercial/industrial purposes.

‘Zero Routine Flaring by 2030’ initiative

In 2015 the World Bank introduced the ‘Zero Routine Flaring by 2030’ initiative[56] which commits governments and oil companies to (a) avoiding the routine flaring of associated gas in any new oilfield development, and (b) seeking to implement economically viable solutions to eliminate legacy routine flaring (i.e. at existing oilfields) as soon as possible and no later than 2030. As of May 2021, there were 93 endorsers of the initiative, including many of the major development banks that have agreed to facilitate cooperation and consider the use of financial instruments to support flaring reduction projects. Other global organizations supporting the initiative include the European Union (EUI), IPPEA, The Latin American Energy Organization (OLADE), The Organization of the Petroleum Exporting Countries (OPEC) and the World Petroleum Council.

The initiative pertains to routine flaring and not to flaring for safety reasons or non-routine flaring which, nevertheless, should also be minimized. Routine flaring of gas is flaring that takes place during normal oil production operations in the absence of sufficient facilities or amenable geology to reinject the produced gas, utilize it on-site, or dispatch it to a market. Venting is not an acceptable substitute for flaring.

The IEA analysis, The Oil and Gas Industry in Energy Transitions[57] finds that the commitments from the World Bank’s ‘Zero Routine Flaring by 2030’ initiative will be an integral component of the path to ending routine flaring globally and the Paris Agreement goal of limiting global warming to well below 2°C above pre-industrial levels.