UNIVERSITA' DEGLI STUDI DI PADOVA

Dipartimento di Ingegneria Industriale DII

Corso di Laurea Magistrale in Energy Engineering

Utilization of flare gas for power generation at Band-e-Karkheh oil field

Relatore: Ali, Paknahad, 2078638

Anno Accademico 2025-2026

TABLE OF CONTENTS

Chapter 1: Introduction

1.1 Background

Gas flaring – the practice of burning off associated natural gas during oil production – has long been a common, but wasteful aspect of the petroleum industry. From the earliest oil wells over a century ago, operators have flared "unwanted" gas due to a lack of economic use or infrastructure, effectively treating it as a disposal method [1]. This routine flaring of associated gas has now become a significant global environmental and energy problem. The volume of gas flared worldwide is enormous: on the order of 150 billion cubic meters (bcm) each year [1]. If captured and utilized, this amount of gas could power entire regions – for instance, the World Bank estimates that the gas flared annually (≈150 bcm) could generate enough electricity to supply all of sub-Saharan Africa [1]. Instead, much of this valuable resource is simply burned at the wellhead, producing emissions without any beneficial use. In an era of growing focus on sustainability and energy efficiency, such continual flaring represents both an environmental liability and a missed economic opportunity. This thesis addresses that dual challenge by exploring a case in which flare gas recovery is employed for on-site power generation. In particular, it examines the Band-e-Karkheh oil field in Iran, where significant volumes of rich associated gas are currently flared, and proposes a technical solution to convert this wasted gas into useful electricity for field operations. The following sections provide context on the global scale of gas flaring, its impacts, and the potential of flare gas recovery, before introducing the specific case study and the scope of this work.

1.2 Global Context of Gas Flaring

Gas flaring is a large-scale global phenomenon. Recent satellite data reveal that approximately 150–151 bcm of natural gas is flared annually at upstream oil and gas facilities worldwide[1]. This is equivalent to roughly 5 trillion cubic feet of gas per year being burned off, an amount that has remained stubbornly high over the past decade. In fact, global flaring increased slightly in recent years: about 151 bcm of gas was flared in 2024, the highest level in almost two decades[1]. The carbon footprint of this practice is immense. Flaring 150 bcm of gas releases on the order of 400 million tonnes of CO_2-equivalent (CO_2e) emissions every year[1]. For perspective, that is more CO_2e than the annual emissions of entire mid-sized countries (indeed, 400 Mt CO_2e exceeds the total emissions of economies like Egypt in 2023) [1]. These emissions come primarily from the conversion of methane to CO_2 in the flame, but also from incomplete combustion and direct venting of methane. Even when flares burn efficiently, each cubic meter of gas flared yields roughly 2.5–2.8 kilograms of CO_2e[1]. In practice, flares often operate at suboptimal efficiency; studies in the United States found actual flare combustion efficiencies ranging from ~87% to 94%, meaning a portion of the methane and other hydrocarbons escapes unburned[3]. This further exacerbates the climate impact, since methane is a far more potent greenhouse gas than CO_2 in the near term.

Globally, gas flaring is highly concentrated in a handful of oil-producing countries. According to World Bank data, just nine countries account for roughly three-quarters of all flared gas[1]. Historically, the top flaring nations include Russia, Iran, Iraq, the United States, and others such as

Venezuela, Algeria, Nigeria, Libya, and Mexico[1]. For example, as of 2024, Russia, Iran, and Iraq remain the three largest flaring countries by volume[1]. This concentration indicates that addressing flaring in a few key regions could significantly reduce the global total. It is worth noting that many of these high-flaring countries are also major oil producers with substantial associated gas production. In some cases, they face domestic energy shortages even as they flare gas: this paradox is evident in countries like Iraq, which flared about 18 bcm in 2023 (over 11% of global flaring) even while struggling to meet power demand [4]. In Iraq's case, the gas flared that year could have generated on the order of 33 GW of electricity if used in power plants[4] – a stark illustration of wasted potential. Recognizing the scale and urgency of the issue, international efforts have been mobilized to curb routine flaring. Notably, the World Bank's **Zero Routine Flaring by 2030 (ZRF)** initiative was launched in 2015, committing governments and oil companies to end routine flaring in new projects and to eliminate legacy flaring by 2030[1]. While some progress has been made (global flaring intensity per barrel of oil has modestly decreased over the past decades[1]), the total volumes remain high. The global context of gas flaring is thus one of a persistent, large-scale practice that the industry and regulators are now pushing to reduce for both environmental and economic reasons.

1.3 Environmental and Economic Implications

The routine flaring of associated gas carries significant environmental and health consequences, as well as economic costs. Environmentally, gas flaring contributes notably to greenhouse gas emissions and climate change. The CO_2 released by flares – about 400 million tonnes CO_2e per year – adds to global warming[1]. Moreover, because flares do not destroy 100% of methane, a portion of this potent greenhouse gas escapes into the atmosphere, further amplifying the climate impact. Even assuming high combustion efficiency (98%), the methane slip from global flaring has been estimated to increase the annual emissions by another ~80 million tonnes CO_2e on a 20-year global warming potential [1]. Incomplete combustion in flares also produces black carbon (soot) particles [1]. Black carbon is a short-lived pollutant with an outsized warming impact, especially when deposited on snow or ice. Studies have suggested, for example, that flaring emissions may be responsible for around 40% of black carbon deposits in the Arctic, accelerating ice melt in that region [1]. Aside from greenhouse gases, flaring emits various air pollutants. The flared gas often contains volatile organic compounds (VOCs), sulfur species, and nitrogen oxides. While high-temperature flaring aims to oxidize these to CO_2, SO_2, NO_x, and water, in reality, many harmful pollutants are released into the local environment. Noxious gases such as benzene (a known carcinogen) can be present in flare emissions[3]. Flares also generate nitrogen oxides and particulates that contribute to smog formation and acid rain in the vicinity of oil fields. Communities living near oil field flares are thus exposed to degraded air quality. Epidemiological research has linked chronic exposure to gas flaring with health problems: increased rates of preterm births, respiratory ailments such as asthma in children, and other pulmonary and cardiovascular issues have been observed in populations near flaring sites[3]. For instance, studies in the United States found that populations within a few kilometers of frequent flaring had higher risks of preterm birth and asthma exacerbation, due to the combination of soot, smog, and toxic chemicals released[3]. These environmental and health externalities underscore why flaring is not merely a visible flame in the sky, but a serious pollution source affecting climate and public health.

Beyond the environmental damage, gas flaring entails a substantial economic loss and opportunity cost. The gas being burned off has monetary value as a fuel or feedstock, which is forfeited when it is flared. By some estimates, the ~150 bcm of gas flared globally in a year could be valued on the order of $10–20 billion USD (depending on market prices). In 2022, for example, around 140 bcm of flared gas was effectively "worth" about $16 billion if it had been brought to market[3]. Thus, flaring represents a direct loss of potential revenue for oil producers and governments (in the form of royalties or taxes on gas sales). In many cases, the countries flaring the most are the ones that could badly use this energy. Flaring deprives national economies of fuel that could generate electricity, produce petrochemicals, or be used for domestic heating and industry. This has been highlighted as a paradox in countries like Iran and Iraq, which flare large volumes while facing energy supply challenges. As one analysis noted in the context of Iraq, *"vast amounts of natural gas that could supply relatively clean-burning fuel for power generation are flared off at wellheads — wasted. Such flaring exacerbates pollution and climate change, while eliminating a source of government revenue and depriving power generators of a valuable feedstock."*bakerinstitute.org. In Iraq's case, because so much gas is flared and thus unavailable for power plants, the country ends up relying on imported gas and even burning more polluting liquid fuels for electricity bakerinstitute.org. This scenario is not unique to Iraq; similar dynamics exist in Iran, Russia, Nigeria, and other flaring nations where capturing flared gas could improve energy self-sufficiency. In short, routine flaring carries a dual penalty: it imposes environmental and health costs on society, and it wastes an economic resource that could otherwise be utilized productively. These implications provide a strong incentive to find ways to reduce or eliminate routine flaring by capturing associated gas and putting it to beneficial use.

1.4 Flare Gas Recovery as a Sustainable Opportunity

Given the significant drawbacks of flaring, there is a growing push to convert this problem into an opportunity through flare gas recovery. Instead of burning off associated gas, producers can *capture, process, and utilize* it – transforming what was once waste into a valuable resource. Flare gas recovery is increasingly seen as a sustainable development opportunity that aligns with both environmental objectives and energy needs. Technically, there are several pathways to use previously flared gas. In large oil fields with sufficient gas volume, the preferred solution is often to conserve the gas by reinjecting it into the reservoir (to maintain pressure) or to collect and transport it via pipeline to be used as fuel or feedstock. However, where reinjection is not feasible and pipelines to markets are lacking (a common scenario in remote or smaller fields), on-site utilization of the gas becomes an attractive alternative[1]. One of the most practical on-site uses is power generation: the associated gas can be used to fuel gas engines or turbines to produce electricity right at the oil field[1]. This electricity can then supply the field's own energy needs (displacing more polluting sources like diesel generators) or even be exported to nearby communities or the grid if infrastructure permits. The World Bank notes that using associated gas for on-site power is a viable way to both avoid flaring and reduce reliance on dirtier fuels[1]. In recent years, significant progress in small-scale gas utilization technologies has enhanced the feasibility of flare gas recovery in onshore fields[1]. Technologies such as modular gas-to-power units, mobile or micro-scale liquefied natural gas (LNG) plants, compressed natural gas (CNG) trucking solutions, and gas-to-liquids processes have been developed and deployed in various pilot projects[1]. These innovations allow even moderate volumes of associated gas to be economically used, whereas in the past they might have been flared due to a lack of scale. For onshore oil fields, especially those not too distant from power demand centers, gas-to-power (using the flared gas to generate electricity) often emerges as one of the most straightforward and impactful options. It directly converts the gas's energy into a useful form and can usually be implemented with relatively proven equipment (e.g., gas engine-generator sets or small turbines).

Aside from the technical viability, flare gas recovery delivers **e**nvironmental benefits and contributes to sustainability goals. Capturing and utilizing gas that would otherwise be flared can virtually eliminate the routine emissions from flares during normal operations. The only time a flare would then be used is for true emergency relief or upset conditions. This means a drastic reduction in continuous CO_2 and pollutant emissions at the site, improving air quality and reducing the carbon footprint of the oil production. Using recovered gas for power generation also has a broader climate benefit: it can displace other fuel sources. For example, if a field currently relies on diesel-fired generators or draws electricity from a coal-intensive grid, then substituting those with gas-fired power from recovered flare gas will lower overall emissions (since natural gas combustion emits less CO_2 per unit energy than diesel or coal). In addition, flare gas recovery aligns with operational improvements – it turns a liability into an asset. Instead of simply managing the flare as a safety device, operators can integrate the gas into their production value chain, improving energy efficiency for the facility. Many oil companies now include flare reduction projects in their sustainability and ESG (environmental, social, governance) strategies, and some governments provide incentives or impose regulations to encourage flare gas utilization[2]. In summary, recovering flare gas represents a win–win solution in many cases: it reduces pollution and greenhouse emissions (supporting climate and public health objectives), while simultaneously creating useful energy or revenue (supporting economic and operational objectives). The challenge lies in selecting the appropriate technology and design for each specific field context, which is exactly the focus of this thesis in the context of the Band-e-Karkheh field.

1.5 Band-e-Karkheh Oil Field: Local Context and Motivation

Band-e-Karkheh is an onshore oil field located in the Dezful Embayment of southwestern Iran (near the Ahvaz region). Discovered in the 1960s but only more recently appraised for development, the field contains significant oil reserves along with associated natural gas in the produced fluids. Like many oil fields in Iran and the Middle East, Band-e-Karkheh currently lacks facilities to capture or export its associated gas production. There is no gas pipeline tied to the field, nor gas re-injection in place, meaning that all the gas produced alongside oil is handled as excess. The result is that the associated gas is routinely flared at the Central Processing Facility (CPF). At present, roughly 36 million standard cubic feet per day (MMSCFD) of gas is flared at Band-e-Karkheh as a matter of routine operation. This volume (36 MMSCFD) corresponds to about 1.02×10^6 standard cubic meters of gas per day – a substantial stream of energy simply being burnt off. What makes the Band-e-Karkheh gas particularly noteworthy is its quality: it is a *rich, high-BTU gas*. Analyses indicate the gas contains a high proportion of heavy hydrocarbons (C_6^+ fractions make up over 50% of the gas by molar volume) with very little inert content. Consequently, the gas has an exceptionally high calorific value, with an estimated higher heating value (HHV) of ~184 MJ per standard cubic meter. For comparison, typical pipeline natural gas (mostly methane) has an HHV on the order of 35–40 MJ/Sm³; thus, the Band-e-Karkheh gas is roughly 4–5 times richer in energy content per volume. This is due to the presence of heavier hydrocarbon gases and vapors (pentanes, hexanes, and heavier), which carry more energy but also can condense into liquids under pressure. Flaring such a rich gas not only means a large emission of CO_2, but also a tremendous waste of energy – each day's flared volume contains on the order of 184 MJ/Sm³ × 1.02×10^6 Sm³ ≈ 1.88×10^8 MJ of energy, enough to fuel significant power generation. At the same time, the field's surface facilities have their own power demand: the CPF and associated infrastructure at Band-e-Karkheh require about 10 MW of electricity to operate (approximately 240 MWh per day). Currently, the development plan for the field is to source this electricity from the national grid, i.e., importing power via transmission lines to run the field's pumps, compressors, and utilities. Relying on the grid entails ongoing operating costs and dependency on an external power supply. It was within this context that the motivation arose to utilize Band-e-Karkheh's *own* flared gas to generate the required power on-site.

The rationale for on-site power generation from the flare gas at Band-e-Karkheh is compelling. By recovering the ~36 MMSCFD of gas that was being flared and using it as fuel for power generation, the field can become self-sufficient in electricity while simultaneously eliminating routine flaring. In effect, the previously wasted gas is turned into ~10 MW of useful power, covering essentially 100% of the CPF's needs. This has multiple benefits. Environmentally, it would cut out the continuous flare, thereby ceasing the routine emissions and pollution from the field's operations (the flare would remain installed only for safety relief in abnormal situations). Operationally, the field would no longer be dependent on the national grid for electricity during normal operation, which could improve reliability and reduce energy costs in the long run. The recovered gas, being very rich, is more than sufficient to feed the power plant; in fact, only a fraction of its energy content is needed to produce 10 MW, so the system could be designed with some turndown or have capacity for additional utilization if needed.

In designing a solution for Band-e-Karkheh's flare gas, careful consideration was given to the *technologies* available and the challenges posed by the gas composition. The extremely high-BTU gas (HHV ~184 MJ/Sm^3) and its heavy fractions mean that any power generation equipment must handle a fuel quite different from standard pipeline gas. One key issue is the methane number (knock resistance) of the fuel–rich gases with many heavy hydrocarbons that tend to have a low methane number, making them prone to engine knock (auto-ignition) in combustion engines. Another issue is that compressing and cooling such rich gas can cause condensate dropout (liquid formation), which must be managed to avoid damaging equipment. After evaluating options, a reciprocating gas engine generator system was selected as the most suitable technology for this application. Reciprocating gas engines (essentially industrial gas-fired piston engines driving generators) offer several advantages for the Band-e-Karkheh scenario: they can handle lower fuel quality (some engine models can be derated or adjusted to use high-BTU, low-methane-number gas), they are efficient at small-to-medium scales (typical electrical efficiency 35–45% for engine plants of a few MW, which is favorable for ~10 MW total output), and they have relatively modest fuel gas pressure requirements. In fact, the chosen design only requires the gas to be compressed to about 5 bar absolute (roughly 4 bar gauge) to supply the engines, which is a much lower pressure than what gas turbines would need. This simplifies the compression system and reduces complexity. The system is conceived with multiple engine-generator units in parallel, totaling ~10 MW capacity. A two-stage compression and knock-out drum arrangement will be installed as a Flare Gas Recovery Unit (FGRU) to take the low-pressure flare gas, remove any condensates or liquids, compress it to the required engine fuel pressure, and feed it to the generators. By implementing this solution, continuous flaring at Band-e-Karkheh can be virtually eliminated under normal operations, as the gas will be consumed for power instead of being burned in an open flare. This case study exemplifies how an oil field in a country like Iran, which is among the top flaring nations, can turn an environmental problem into a self-reliant energy solution. The motivation driving this project is thus rooted in enhancing environmental performance, improving energy efficiency, and aligning with wider efforts in Iran and globally to reduce routine flaring.

1.5.1 Iran's Energy Context and Crisis

Iran possesses the world's second-largest proven reserves of natural gas and the fourth-largest reserves of crude oil, yet the country faces recurring energy shortages that reflect structural inefficiencies rather than resource scarcity. Rapid population and industrial growth, heavily subsidized domestic energy prices, and aging infrastructure have created a situation where winter gas deficits reach up to 200 million m^3 per day and summer electricity demand routinely exceeds generation capacity. As a result, blackouts and fuel rationing have become frequent, while at the same time, Iran remains among the top three gas-flaring nations globally. This paradox—flaring billions of cubic meters of valuable associated gas each year while struggling to supply energy domestically—highlights the urgent need for efficient resource utilization.

Flare-gas-to-power projects such as the one proposed for the Band-e-Karkheh oil field directly address this imbalance: by recovering and using associated gas on-site, they can reduce national energy waste, improve grid stability, and contribute to Iran's broader goals of self-sufficiency and emission reduction.

1.6 Scope and Structure of the Thesis

This thesis focuses on evaluating and designing the technical solution for flare gas recovery and on-site power generation at the Band-e-Karkheh field, and assessing its environmental performance. It is important to clarify the scope: economic feasibility analysis is not included in this work. In other words, detailed cost estimation, financial modeling (CAPEX/OPEX), or economic profitability assessment are beyond the scope of this thesis. The emphasis is instead on *technical viability*, design considerations, and the expected environmental benefits of the proposed system. The rationale for excluding an economic analysis is to concentrate on whether the solution works technically and delivers the desired reduction in flaring and emissions; questions of economic payback or investment decision are left for future studies or stakeholders to consider. Within this technical focus, the thesis covers aspects such as gas characterization, technology selection, system design (compression requirements, engine configuration, etc.), and an analysis of the environmental improvement (e.g., estimated emissions reduction) achieved by the project.

The thesis is organized into **five chapters** as follows:

- **Chapter 1: Introduction** – (the current chapter) provides the background of the gas flaring issue and introduces the specific case of Band-e-Karkheh, along with the objectives, scope, and motivation of the study. It frames the problem and the proposed solution in a global and local context.
- **Chapter 2: Environmental and Technological Background** – this chapter offers a detailed literature review and background on two key aspects: (a) the environmental impacts of gas flaring and the regulatory landscape (including global initiatives and country-specific contexts relevant to flaring reduction), and (b) the technological options for flare gas utilization. It surveys various methods of flare gas recovery (re-injection, gas-to-power, gas-to-liquids, CNG/LNG, etc.), their advantages and limitations, and prior case studies or projects in this domain. This sets the stage for understanding why the chosen solution is appropriate and what the state-of-the-art is.
- **Chapter 3: Case Study – Band-e-Karkheh Field** – this chapter zooms in on the case study itself. It presents the local context in depth: a description of the Band-e-Karkheh field development, the characteristics of the produced fluids, the current flaring situation, and the energy needs of the facility. The chapter quantifies the flare gas volume and analyzes its composition (highlighting the high calorific value and other unique properties). It also discusses the challenges and opportunities specific to this field (for instance, lack of gas export infrastructure, availability of space for new equipment, and any regional factors like grid reliability or policy incentives to reduce flaring). The aim is to clearly define the design basis for the recovery system.
- **Chapter 4: Engineering Design Proposal** – this is the core engineering chapter where the proposed flare gas recovery and power generation system is developed. It details the design of the FGRU and power plant, including the process flow (from flare line tie-in, gas conditioning, compression stages, to engine generators and electrical integration). Key design parameters are provided (such as compressor sizing, engine selection and performance, control and safety systems, etc.), all tailored to the Band-e-Karkheh case. The chapter likely includes simulations or calculations to size equipment and to predict performance (e.g., ensuring the 10 MW power output can be met, estimating the fuel consumption, and handling variations in gas flow). Operational considerations, such as how the system will respond to fluctuations or

emergencies, are also described. The design is presented in accordance with engineering standards and practical constraints, demonstrating that the flare gas recovery solution can be technically implemented at this site.

- **Chapter 5: Results and Conclusions** – the final chapter presents the outcomes of the study and draws overall conclusions. It summarizes how the proposed system performs in terms of meeting the field's power demand and eliminating routine flaring. It may offer an analysis of the environmental performance, for example, estimating the reduction in greenhouse gas emissions achieved by the project (such as annual CO_2 savings by not flaring 36 MMSCFD of gas). Any improvements in operational efficiency or other co-benefits are noted. The chapter also discusses any limitations, challenges, or considerations for implementation (for instance, what operational vigilance is needed to manage the rich gas, or any recommendations for further work, like an economic assessment or pilot testing). Finally, the conclusions tie back to the broader context: the Band-e-Karkheh project is used to illustrate how on-site flare gas-to-power can be a viable solution in oil fields with similar conditions, contributing to both local energy supply and global flaring reduction efforts.

Overall, the structure of the thesis is designed to first build a foundation of understanding about gas flaring and its mitigation (Chapters 1 and 2), then apply that understanding to a real-world case (Chapter 3), propose a concrete engineering solution (Chapter 4), and evaluate its implications (Chapter 5). By focusing on the technical and environmental aspects, this work aims to demonstrate that recovering flare gas for on-site power is not only technically feasible but also highly beneficial from a sustainability standpoint, especially in a country like Iran, where large volumes of gas are flared and energy efficiency is a national priority. The hope is that this study can serve as a reference or impetus for similar projects to convert routine flaring into productive use, aligning with the global initiative to eliminate routine gas flaring in the coming years.

Sources:

1. World Bank, *Global Gas Flaring Reduction Partnership – Gas Flaring Explained*, 2024 worldbank.orgworldbank.orgworldbank.orgworldbank.orgworldbank.orgworldbank.orgworldbank.org.
2. World Bank, *Global Gas Flaring Tracker Data (July 2025)*worldbank.orgworldbank.org.
3. RMI (Gordon *et al.*), *"Where Gas Flaring Is Endangering Communities,"* 2024 rmi.orgrmi.orgrmi.org.
4. Baker Institute, M. Alam, *"Iraq's Electricity Shortage and the Paradox of Gas Flaring,"* 2025 bakerinstitute.orgbakerinstitute.org.
5. **Band-e-Karkheh Field Data (Project Documents)** – Internal data on Band-e-Karkheh oil field development and flare gas characteristics.

Chapter 2: Gas Flaring – Environmental Impacts and Mitigation Technologies

Gas flaring – the controlled burning of excess natural gas during oil production – remains a widespread practice with significant global and local consequences [1][2]. Each year, approximately 150 billion cubic meters of natural gas are flared worldwide, wasting a valuable energy resource and emitting roughly 400 million tonnes of CO_2-equivalent greenhouse gases [3]. A handful of oil-producing countries (notably Russia, Iran, Iraq, the United States, and others) account for about 75% of global flaring volumes [4].

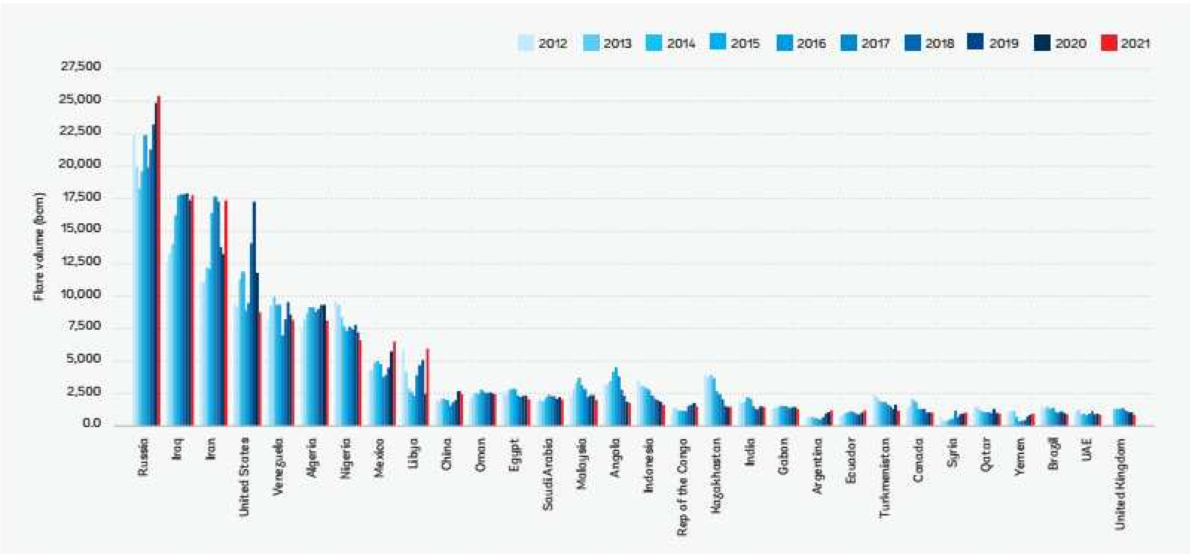


Figure 2.1 *Flare volumes for the top 30 flaring countries from 2012 to 2021 (sorted by 2021 volume, shown in red)*
Source: NOAA, Payne Institute and Colorado School of Mines, GGFR)

This chapter provides a critical review of the literature on gas flaring, examining its environmental impacts at both global and local scales, the differences between offshore and onshore flaring practices, and the main technologies available to mitigate flaring. A comparison of these mitigation technologies is summarized in a table, and the chapter concludes by connecting these general insights to the Band-e-Karkheh case study to follow in Chapter 3.

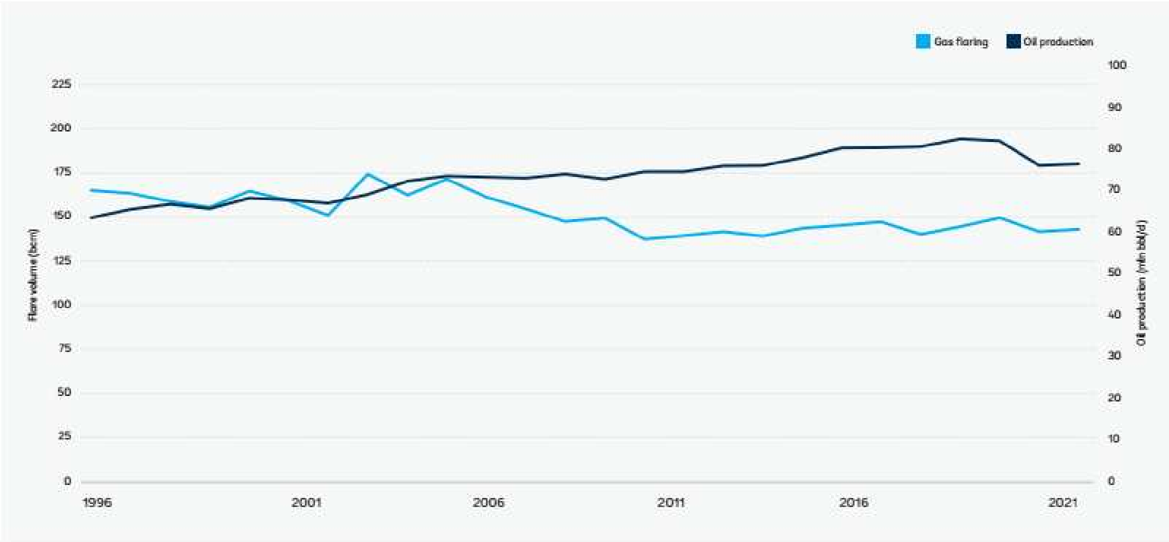


Figure 2.2 Global gas flaring and oil production 1996 to 2021 (flaring only at upstream oil & gas and LNG plants)
Source: NOAA, Payne Institute and Colorado School of Mines, GGFR)

2.1 Global and Local Environmental Impacts of Gas Flaring

2.1.1 Global Climate Impacts

Flaring contributes significantly to global greenhouse gas (GHG) emissions and climate change. In a high-temperature flame, most hydrocarbons in the gas are converted to carbon dioxide (CO_2) and water; even efficient flares (98% combustion efficiency) release large quantities of CO_2 [3]. Current estimates suggest gas flaring adds roughly 400 million tons of CO_2-equivalent emissions per year [3] – exceeding the annual emissions of mid-sized economies. Moreover, incomplete combustion in flares means some methane (CH_4), the primary component of natural gas, escapes unburned. Methane has a global warming potential over 80 times that of CO_2 on a 20-year timescale, so even a few percent of uncombusted methane significantly amplifies the climate impact [5].

Black carbon (soot) is another byproduct of inefficient flaring; despite its short atmospheric lifetime, soot darkens surfaces and accelerates ice/snow melt. Notably, research indicates flaring may be responsible for about 40% of black carbon deposits in the Arctic each year [6], a striking linkage between oilfield flares (even at high latitudes offshore) and polar climate feedbacks.

2.1.2 Local Environmental and Health Impacts

While climate effects are global, gas flaring also imposes acute local environmental degradation and public health hazards. Flaring generates a host of air pollutants, which can cause acid rain and deteriorate air quality [7][8]. These pollutants include:

- **Nitrogen oxides (NO_x)**
- **Carbon monoxide**
- **Sulfur dioxide (SO_2)**
- **Unburned hydrocarbons**
- **Particulate matter**

In regions with high-sulfur ("sour") gas, flaring oxidizes hydrogen sulfide into SO_2, which later forms acidic compounds in the atmosphere. Acidic precipitation from chronic flaring has been documented to damage agriculture, forests, soils, and water bodies near flare sites [7]. For example, in the Niger Delta of Nigeria (a region historically plagued by extensive onshore flaring), studies have observed altered vegetation and soil acidification in proximity to flare stacks [9]. Soot deposition is often visible on buildings near flares, and when washed by rain, this contaminates local water sources and farmlands [8].

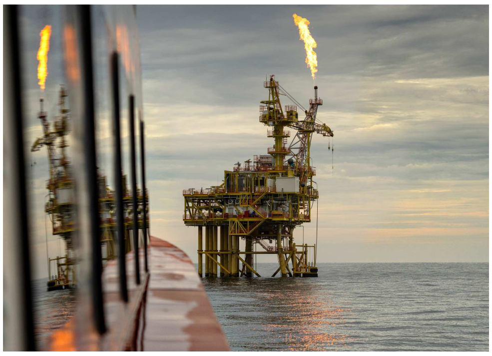
The public health burden in communities near flaring is well-documented. Incomplete combustion in flares means that people downwind are exposed to toxic substances such as **benzene** and other volatile organic compounds, as well as fine particulate soot. Epidemiological studies associate living near gas flares with higher rates of respiratory illnesses (asthma, bronchitis), adverse birth outcomes, and even certain cancers [10][11]. Flaring has been linked to increased prevalence of preterm births and pediatric asthma in affected communities [10]. Ground-level ozone and smog can form from flare emissions, contributing to cardiovascular and neurological problems [10]. Over 250 distinct toxins have been identified in flare plume emissions – including carcinogens like benzopyrene and heavy metals – which pose long-term health risks [11].

Notably, a U.S. study estimated that in one flaring-intensive region, flare-related air pollution could be causing dozens of premature deaths and thousands of respiratory illness cases annually among nearby populations [12][13]. In sum, flaring is not only a climate issue but also an environmental justice concern, as its negative impacts often fall disproportionately on vulnerable, marginalized communities living near oil fields [14][10].

Figure 2.3*United States flare volume versus oil production, 2012 to 2021*

2.2 Offshore vs. Onshore Flaring Practices

Operational practices and regulatory frameworks for gas flaring can differ markedly between offshore and onshore oil developments. Onshore flaring typically occurs at oil wells or processing facilities on land, sometimes in proximity to populated areas or farmland (as in parts of Nigeria, the Middle East, and the United States). Offshore flaring, by contrast, takes place on offshore platforms or floating production units at sea, far from direct human habitation. These contextual differences lead to different impacts and management approaches.



2.2.1 Volume and Frequency

Offshore platforms generally handle large production volumes and may flare substantial gas during well testing, start-ups, or emergencies. However, many offshore operations have made strides to minimize routine flaring. For instance, in the North Sea (UK sector), offshore flaring volumes dropped by ~50% between 2018 and 2022, reflecting stricter regulation and industry efforts [15]. In contrast, onshore oil fields without gas infrastructure often continue routine flaring. The UK saw a revealing divergence: even as offshore flaring fell, flaring at onshore oil fields reached record-high levels in 2022 [16]. This suggests that onshore sites (especially smaller or remote wells) may lag in flaring reduction, possibly due to economic constraints or less oversight, whereas offshore operators face more scrutiny to curb emissions.

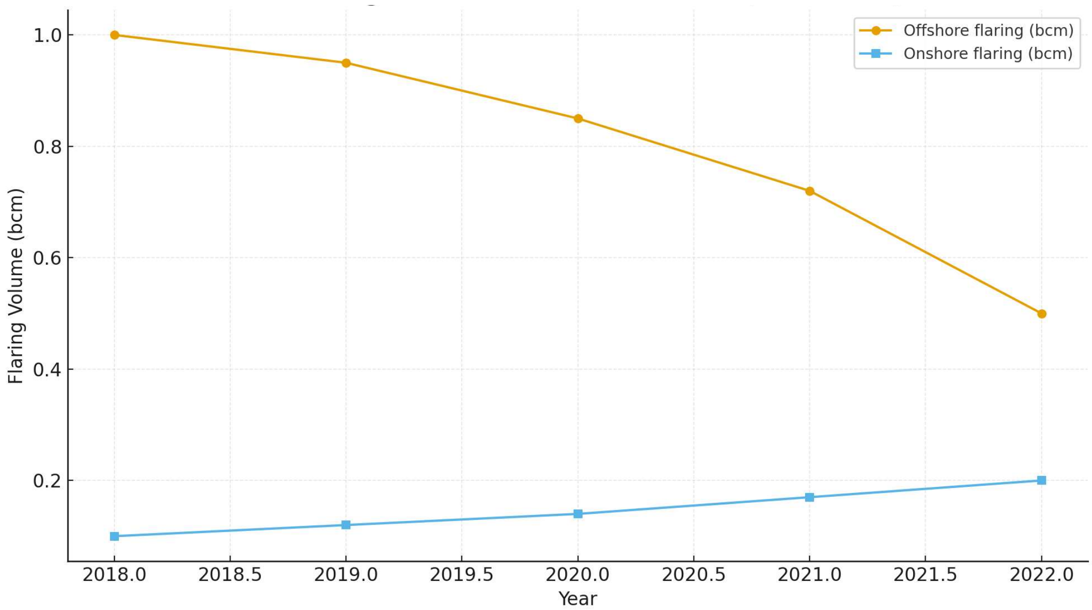


Figure 2.4 *UK Flaring Trends: Offshore vs Onshore (2018–2022)*

2.2.2 Regulatory Environment

Offshore flaring is frequently subject to tighter regulatory limits and economic disincentives, given the concentrated nature of offshore production. For example, Norway's offshore oil industry – aided by a robust carbon tax and emission trading – has achieved 81% lower flaring and venting volumes than the UK, despite producing more than double the oil [17]. This success is attributed to decades of policies (like Norway's early 1990s offshore carbon tax) that made flaring financially punitive, forcing operators to invest in gas utilization or reinjection [18]. Onshore flaring regulations vary widely by country and region; some jurisdictions impose fines or bans, while others historically have had lax enforcement. In regions with artisanal or smaller-scale oil production, onshore flaring may go relatively unchecked. However, there is a global trend toward tighter controls – for instance, the World Bank's "Zero Routine Flaring by 2030" initiative aims to eliminate routine flaring in both new and existing fields worldwide [19].

2.2.3 Proximity to Communities

A key difference is that onshore flaring directly affects nearby communities and ecosystems, while offshore flaring's immediate impacts are mainly marine and atmospheric. Onshore flares often loom over towns or agricultural land, resulting in the local air pollution and health issues discussed earlier. By contrast, an offshore flare's pollutants dissipate over the ocean, so coastal communities might experience less acute exposure (aside from any regional pollution transport). That said, offshore flaring still contributes to regional problems – for example, flaring by Arctic offshore operations contributes to black carbon deposition on ice, as noted above [6]. Additionally, some sensitive marine environments can be affected by chronic flaring (e.g., illumination affecting bird migration, noise affecting wildlife), although such impacts are less studied than terrestrial ones.

2.2.4 Infrastructure and Mitigation Options

Offshore installations face space and weight constraints that make installing large gas-capture equipment challenging. As a result, many offshore operators prioritize gas reinjection – i.e., pumping associated gas back into the reservoir – to avoid flaring when no export route is available [20]. Reinjection offshore is common in oil fields aiming for enhanced oil recovery or pressure maintenance, effectively conserving the gas until it can be produced later. Onshore fields, conversely, might have the option to build gathering pipelines, small-scale power plants, or other utilisation projects on site. However, if the oil field is remote with no gas market, onshore operators sometimes simply flare the gas as the cheapest short-term solution [21][22]. Thus, the choice of mitigation often differs: offshore = reinject or centralized solutions, onshore = local utilization or flaring. In recent years, both offshore and onshore projects have converged on the goal of zero routine flaring, through some combination of technology and stricter practice.

In summary, onshore flaring tends to have more direct human and environmental interactions, whereas offshore flaring is better isolated but still environmentally consequential. The overarching challenge is similar: finding ways to use or conserve associated gas instead of burning it off. The next sections review the main technological approaches to achieve this.

2.3 Mitigation Technologies for Flaring Reduction

Multiple technologies and strategies have been developed to capture the gas that would otherwise be flared and convert it into useful products or safely store it. The principal categories reviewed here are: gas-to-power solutions, gas-to-liquids (GTL) processes (encompassing both large-scale plants and emerging modular units), and gas reinjection/compression methods. Each approach has distinct efficiency ranges, scales of application, and pros and cons, as summarized later in Table 1. A recurring theme in the literature is that no single solution fits all cases; the choice depends on the volume of gas, location (onshore/offshore), economic factors, and whether the goal is short-term utilization or long-term elimination of flaring [23][24].

2.3.1 Gas-to-Power (Engines, Turbines, CHP)

One straightforward way to utilize associated gas is to generate electricity on-site, often termed **"gas-to-wire"**. In this approach, the flared gas is diverted as fuel for engines or turbines to produce power, which can be used locally or fed into a grid. Reciprocating gas engines (gensets) and gas turbines are commonly employed. Internal combustion gas engines are well-suited for small to medium scales, while industrial gas turbines may be used for larger power outputs or when high-quality waste heat can be recovered. The addition of heat recovery systems (for example, in a Combined Heat and Power (CHP) configuration) allows the usage of exhaust heat for industrial processes or heating, thereby greatly improving overall energy efficiency.

Studies indicate that electricity generation is an attractive option, particularly for small volumes of flared gas that would be uneconomical to capture for sale [25]. The key benefit is that even a few hundred kilowatts to a few tens of megawatts of power can be generated from otherwise wasted gas, supplying energy to oilfield operations or nearby communities that might otherwise burn diesel for power. Modern gas engines can achieve electrical efficiencies around 30–45%, depending on size and design [26]. For example, high-speed Jenbacher engine generators report ~44% efficiency in power-only mode, and when configured as CHP systems, the total energy efficiency can reach ~80–90% through utilization of waste heat [26]. This implies that gas-to-power not only prevents waste but can also displace more carbon-intensive fuels (like diesel) that would have been used for the same energy output [27][28]. Deployments of flare gas power units in remote oilfields have demonstrated reductions in diesel consumption and CO_2 emissions, alongside cost savings for operators (avoiding diesel transport to the site) [29][30].

Advantages:

- Gas-to-power solutions are relatively modular and quick to implement. Containerized generator sets can be installed at the well site with a relatively small footprint – an important factor for both remote onshore pads and offshore platforms [31].
- They are also fuel-flexible within limits: many gas engine designs can handle fluctuations in gas composition (calorific value, methane content) and moderate levels of impurities after minimal conditioning [32].
- Using gas for power yields an obvious co-benefit: it destroys methane (which would have an 80× higher warming effect if vented) by combustion, converting it to the far less potent CO_2 [31].

Limitations:

- It does not eliminate carbon emissions; it simply uses the carbon for energy. One analysis noted that while on-site electricity generation from flare gas is often economically viable, it yields only limited CO_2 reduction benefits relative to flaring [34][35].
- Power generation requires a local demand or a grid connection. In very remote areas, if there is no use for the electricity, running generators just to burn gas is senseless.
- The gas often needs treatment before use in engines/turbines: removal of excess liquids (condensate), dehydration, and scrubbing of hydrogen sulfide or other contaminants to avoid engine damage [33].
- There are operational challenges: gas engines require maintenance and skilled operation, which might be difficult in remote flaring locations. They also must handle variability – if flaring is intermittent, the power system needs to ramp up and down or have a steady supply of gas.

Despite these challenges, gas-to-power is highlighted in many studies as a practical and relatively low-cost flare mitigation, especially for fields with smaller associated gas streams [23][36].

2.3.2 Gas-to-Liquids (GTL): Large-Scale vs. Modular

Another major category of flare gas utilization is conversion of the gas into liquid fuels or chemicals – broadly termed **gas-to-liquids (GTL)**. By chemically transforming methane-rich associated gas into longer-chain hydrocarbons or other liquid products, the gas is effectively "monetized" in a portable form. Liquids (such as synthetic crude, diesel, naphtha, or methanol) can be trucked or stored easily, overcoming the lack of gas pipeline infrastructure that often causes flaring. GTL technologies have been deployed in two very different scales: large, world-scale GTL plants and newer small-scale/modular GTL units.

2.3.2.1 Large-Scale GTL Plants

These are massive industrial facilities that process substantial gas volumes (on the order of hundreds of millions of cubic feet per day) into liquid fuels using catalytic chemical reactions (commonly Fischer–Tropsch synthesis). Several large GTL projects have been built globally, usually where a giant gas reserve is available. For example, Shell's Pearl GTL plant in Qatar – the largest in the world – can produce about 140,000 barrels per day of liquids from Qatar's North Field gas, and it required an investment of roughly $19 billion [37][38]. These facilities prove that gas can be converted into high-value, ultra-clean fuels on a large scale. The efficiency of large GTL (energy in gas to energy in liquid) is fairly high, often in the range of 60–70% [40][41]. From a flaring perspective, however, such mega-projects are not a direct solution for dispersed flare sites – they are only viable when a huge gas stream is available and flaring can be aggregated or eliminated field-wide.

2.3.2.2 Small-Scale and Modular GTL

In the past decade, significant R&D has gone into downsizing GTL technology to create modular, transportable units that could be deployed at or near oil fields to convert associated gas on-site [42][43]. These modular GTL plants are essentially miniature chemical plants, often built in containerized modules. They use the same core steps – gas pre-treatment, syngas generation, and catalytic synthesis – but on a scale of tens to a few hundred barrels per day of liquids, instead of tens of thousands [44][45]. A notable demonstration was INFRA Technology's M100 GTL pilot plant near Houston, which in 2018 showed production of 100 barrels/day of synthetic oil from ~1 million cubic feet per day of gas, occupying only about 4,000 square feet of space [46]. This exemplifies the promise of modular GTL: a skid-mounted unit can turn a small flare (say 1–5 MMscf/d of gas) into a few hundred barrels of liquids per day, which can be trucked out with existing oil shipments. By producing liquid fuels on-site, modular GTL aims to "end flaring" at remote wells [47].

Advantages of GTL:

- Whether large or small, GTL produces saleable commodities and can thereby create an economic incentive to capture flare gas. Large GTL plants can consume huge volumes of gas, drastically reducing flaring on a regional scale [35].
- The liquids produced are typically high quality (sulfur-free, etc.), helping meet cleaner fuel demands [48].
- In the case of small GTL units, the main advantage is mobility and scalability – units can be deployed at a cluster of wells, and multiple modules can be added to scale up capacity as needed [42][43].
- Liquids are easier to store and transport than gas – no high-pressure pipelines or compressors are needed for the product, as it can be trucked using standard fuel tankers.

Limitations of GTL:

- Large GTL plants are capital-intensive mega-projects, affordable only to majors or state companies. They are unsuitable for the scattered nature of many flare sources.
- Small GTL plants, while cheaper in absolute terms, still suffer from economies of scale – the cost per barrel produced is higher for small units, and many have struggled with economic viability at low oil prices.
- Technical challenges include achieving high conversion efficiency in a small footprint, managing catalysts, and ensuring reliable operations with minimal staffing. Early field pilots have had mixed success [49].
- GTL generally needs very clean feed gas (sulfur < 1 ppm, no olefins, etc.), so significant front-end gas processing is required, which adds to the footprint and cost.
- GTL does not eliminate carbon emissions; it transfers carbon into liquid fuels, which, when combusted by end-users, emit CO_2.

Overall, modular GTL is a promising avenue for flare mitigation, but continued improvements in cost and reliability are needed for wide adoption [50][51].

2.3.3 Gas Reinjection and Compression

The third major strategy is to capture the associated gas and re-use or store it without immediate conversion to energy. This typically means either re-injecting the gas back into the subsurface reservoir or compressing and transporting the gas to be used elsewhere. Reinjection has long been practiced in oil fields as a means of pressure maintenance or simply to dispose of gas when no market exists. Gas compression for transport could include sending the gas into a pipeline if one is nearby, or compressing it into CNG or LNG for trucking out of the field (small-scale mobile LNG units are an emerging option) [52].

Advantages:

- The primary benefit of reinjection is that it can achieve near-100% elimination of flare emissions. By not combusting the gas at all, CO_2 and pollutant emissions are avoided.
- Reinjection is often synergistic with reservoir management – injecting gas can enhance oil recovery (EOR) by maintaining reservoir pressure or sweeping oil, thereby increasing oil production.
- When compared to complex utilization schemes, reinjection is conceptually straightforward and often faster to implement if the infrastructure (compressors and injection wells) is in place.
- Compressing gas to a pipeline or tanker allows the gas to be utilized as fuel or feedstock elsewhere, turning a liability into revenue [53].

Limitations:

- The constraints of reinjection/compression are largely technical and economic. Not every reservoir can accept large volumes of gas; there may be geological limitations, or it might cause operational issues.
- Compressor stations and injection wells are expensive, and they consume energy. For older or marginal fields, companies may be reluctant to invest in such facilities without a regulatory mandate [55].
- High-pressure gas injection can pose safety issues and requires continuous monitoring.
- Gas export via pipelines is limited by the availability of pipelines and markets. In remote areas, building a new pipeline may be cost-prohibitive if gas volumes are small.

In summary, while reinjection/compression is highly effective environmentally, it is not always technically or economically feasible in every situation [20]. This underscores why flaring persists: operators often face significant challenges in capturing, treating, and transporting associated gas, especially if the flared volumes are dispersed and infrastructure is absent [55].

Beyond technical feasibility, economic and regulatory factors remain decisive in determining implementation. Many flare gas recovery projects are not realized due to high capital expenditure, uncertain fuel prices, or insufficient incentives for operators to invest in infrastructure. Even when proven technologies exist, the absence of clear policies, enforcement mechanisms, or markets for the recovered gas often leads companies to continue flaring as the least-cost option. Global initiatives, such as the World Bank's *Zero Routine Flaring by 2030* and regional carbon pricing schemes, highlight the growing role of policy frameworks in overcoming these barriers and accelerating adoption.

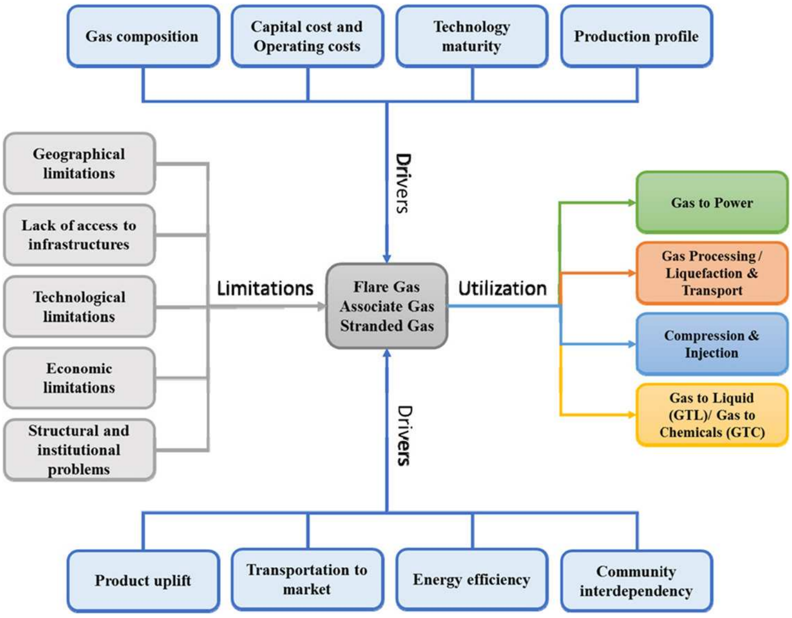


Figure 2.5 *Drivers, limitations, and utilization pathways for flare gas, including gas-to-power, gas processing and transport, compression and injection, and gas-to-liquids (GTL). Adapted from "A review on the potentials of flare gas recovery applications in Iran" (Journal of Cleaner Production, 2020).【https://doi.org/10.1016/j.jclepro.2020.124964】*

2.4 Comparison of Flaring Mitigation Technologies

Each mitigation approach has a distinct profile in terms of efficiency, scale of application, advantages, and limitations.

2.4.1 A Comparative Assessment of Flare Gas Mitigation Options:

2.4.1.1 Gas-to-Power (GTP) Technologies

Gas-to-power technologies, which include **reciprocating engines**, **gas turbines**, and **combined heat and power (CHP)** units, represent a versatile option for mitigating flared gas. These systems typically achieve electrical efficiencies in the range of 30–45%, which can increase to as high as 90% when waste heat is recovered. The modular nature of GTP technology allows for deployment at various scales, from a few hundred kilowatts to tens of megawatts, making it suitable for small to medium flare volumes.

Key Advantages:

- **Rapid Installation:** GTP units can be deployed relatively quickly.
- **Electricity Generation:** They provide a source of useful electricity that can be used on-site or exported to the grid.
- **Fuel Displacement:** The use of flare gas displaces diesel fuel, leading to significant cost and emission reductions.
- **Gas Quality Tolerance:** These systems can tolerate moderate variations in the quality of the feed gas.

Key Disadvantages:

- **Continued Emissions:** While **methane slip** is lower than in flaring, these technologies still emit CO_2.
- **Operational Requirements:** A stable gas supply and a consistent local demand for electricity are necessary for viable operation.
- **Gas Pre-Treatment:** Gas often requires pre-treatment to remove contaminants that could damage the equipment.
- **Maintenance Demands:** Engines and turbines require regular maintenance, which can be a significant logistical challenge in remote locations.

2.4.1.2 Large-Scale Gas-to-Liquids (GTL) Plants

Large-scale **gas-to-liquids (GTL)** plants are designed for very high throughput, typically requiring more than 100 million standard cubic feet of gas per day. These facilities achieve thermal efficiencies of approximately 60–70% and produce tens of thousands of barrels per day of premium-quality liquid fuels, such as sulfur-free diesel and naphtha, which are easily transported. As such, large GTL facilities represent a proven means to eliminate substantial volumes of flaring.

Key Advantages:

- **High Volume Elimination:** Capable of processing and eliminating massive quantities of flared gas.
- **High-Value Products:** Produces premium liquid fuels that are valuable and easily integrated into existing supply chains.

Key Disadvantages:

- **High Capital Cost:** Requires multi-billion-dollar investments.
- **Long Timelines:** Construction and commissioning are lengthy processes.
- **Operational Complexity:** These are complex industrial plants requiring specialized operation.

- **Market and Supply Dependency:** Viability depends on a sustained gas supply and favorable fuel market conditions.
- **Lack of Modularity:** Their large, monolithic design makes them unsuitable for smaller or dispersed flaring sources.

2.4.1.3 Modular Gas-to-Liquids (GTL) Systems
In contrast to large-scale facilities, modular GTL systems are engineered for small to medium-scale applications. They typically handle gas volumes of around 1–20 million standard cubic feet per day, producing 100–1000 barrels of liquid products daily. Pilot units have reported efficiencies in the range of 40–60%. These systems utilize skid-mounted modules that can be deployed directly at remote oil fields and scaled up by adding more units. The output can include syncrude, methanol, or other liquid products that can be transported using existing infrastructure.

Key Advantages:
- **Flexibility and Scalability:** The modular design allows for flexible deployment and easy scaling to match the gas volume.
- **Remote Deployment:** Skid-mounted units are suitable for installation at remote field locations.

Key Disadvantages:
- **Emerging Technology:** The operational reliability and economic viability of these systems are not yet fully proven on a commercial scale.
- **Economic Performance:** They exhibit lower efficiency and higher per-unit costs when compared to large-scale GTL plants.
- **Gas Sensitivity:** These systems are sensitive to gas composition and require thorough clean-up processes and steady gas flows.
- **Capital Investment:** Capital requirements may still be prohibitively high for some smaller flare sites.

2.4.1.4 Gas Reinjection and Compression
The strategy of gas reinjection and compression avoids combustion entirely, thereby achieving a near-total elimination of flaring emissions. In this process, the associated gas is compressed—which consumes approximately 5–10% of its energy—and then re-injected into geological reservoirs or transported away via pipelines. This approach is applicable across a wide range of scales, from single wells to giant fields, and is a widely used technique, particularly in offshore operations.

Key Advantages:
- **Complete Emissions Avoidance:** Prevents the release of **CO_2**, **NOx**, and soot associated with combustion.
- **Enhanced Oil Recovery (EOR):** Reinjection can help maintain reservoir pressure, thereby increasing oil production.
- **Gas Monetization:** Offers a pathway to monetize the gas if pipeline connections exist for its transport and sale.

Key Disadvantages:
- **Geological Constraints:** The feasibility of reinjection is dependent on suitable geological formations.
- **High Costs:** Involves high capital and operational costs associated with compressors and injection wells.

- **Limited Marketability:** The gas is not immediately marketable unless transportation infrastructure is in place or future extraction is planned.
- **Continuous Operation:** Requires a continuous power supply for compression and constant monitoring.
- **Safety Risks:** The risk of reservoir over-pressurization must be carefully managed.

The following table summarizes these characteristics based on the literature review:

Comparison of Gas Utilization Technologies

Technology	Efficiency	Scale	Key Pros	Key Cons
Gas-to-Power (Engines, Turbines, **CHP**)	30–45% electrical; up to 90% with **Combined Heat and Power (CHP)**	Small to medium (**kW–MW** range)	Modular, quick deployment, produces useful electricity	Still emits **CO_2**, needs a steady gas supply and electricity demand, maintenance is required
Gas-to-Liquids (Large **GTL**)	~60–70% thermal	Very large (>100 **MMscf/d**; tens of thousands **bpd**)	Proven at scale, produces high-quality liquid fuels, eliminates large flares	Multi-billion dollar cost, complex, long build time, not modular
Gas-to-Liquids (Modular **GTL**)	~40–60%	Small to medium (1–20 **MMscf/d**; 100–1000 **bpd**)	Deployable at remote sites, scalable, produces liquid fuels	Emerging technology, higher cost per unit, requires clean and steady gas
Gas Reinjection / Compression	N/A (energy conserved; 5–10% loss in compression)	Small to very large (single well to >100 **MMscf/d**)	Eliminates emissions, aids in **enhanced oil recovery (EOR)**, field-proven	Requires suitable geology, costly compressors and wells, provides no immediate revenue

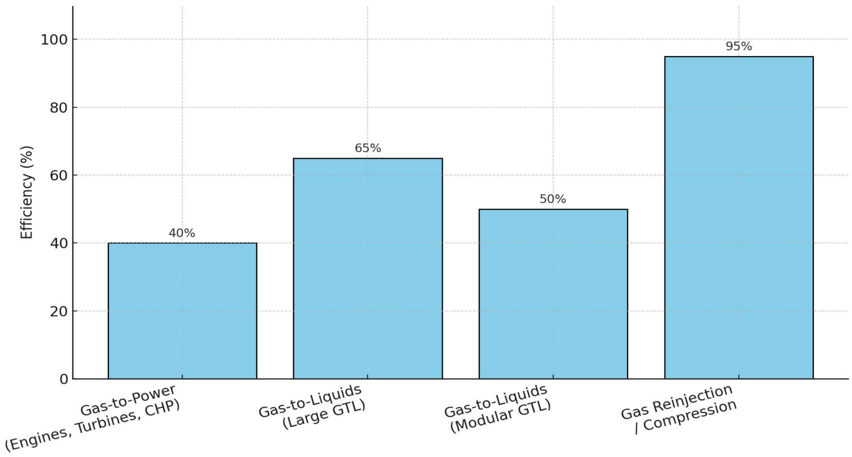


Figure 2.6 *– Comparative efficiency of main flare-gas-utilization technologies: Gas-to-Power (Engines, Turbines, CHP), Gas-to-Liquids (Large GTL and Modular GTL), and Gas Reinjection / Compression.Data adapted from literature review summarized in Table 2.1*
sources: World Bank 2020; Journal of Cleaner Production 2020

2.5 Transition to Case Study: Band-e-Karkheh Field

In this chapter, the broad impacts of gas flaring and the spectrum of technologies available to reduce or eliminate it were reviewed. We have seen that flaring is a significant environmental issue – contributing to climate change and local pollution – and that multiple mitigation strategies exist, each with its own trade-offs. From generating on-site power to deploying cutting-edge micro-GTL plants or re-injecting gas underground, the optimal solution depends on field-specific conditions. Taken together, the literature shows that **no universal solution exists for flare gas mitigation**. Each technology has strengths and drawbacks, and its suitability depends on gas composition, production volumes, site infrastructure, market access, and regulatory context. In practice, technical solutions alone rarely succeed without parallel attention to economics, governance, and long-term operational capacity. This underscores the need for site-specific evaluations rather than one-size-fits-all prescriptions.

In the next chapter, the Band-e-Karkheh oil field will be described as a case study to ground these concepts in a real-world scenario. Band-e-Karkheh, located in southwest Asia, presents an opportunity to apply the general principles discussed here to a practical project. Chapter 3 will examine how the environmental considerations and technologies from this literature review inform a flaring reduction strategy for Band-e-Karkheh. By analyzing this particular field – its flaring history, gas volume, and the mitigation measures being implemented or proposed – how the general approaches (gas-to-power, GTL, reinjection, etc.) can be tailored to a specific context will be illustrated. This transition from theory to practice will highlight the challenges and successes of striving for "zero routine flaring" at Band-e-Karkheh, thereby connecting the critical review of global literature in Chapter 2 to the focused case study analysis in Chapter 3 [54][58].

References

- [1][7][8][9][11][12][13] Global Impact of Gas Flaring: https://www.scirp.org/journal/paperinformation?paperid=20231
- [2][3][5][6][19][20][52][53][54][55] What is Gas Flaring?: https://www.worldbank.org/en/programs/gasflaringreduction/gas-flaring-explained
- [4][42][43][44][45][46][47][50][51] These Modular Gas-to-Liquids Plants Could End Gas Flares | Engineering For Change: https://www.engineeringforchange.org/news/these-modular-plants-could-end-gas-flares/
- [10][14] Where Gas Flaring Is Endangering Communities - RMI: https://rmi.org/where-gas-flaring-is-endangering-communities/
- [15][16] Offshore flaring halves in four years but onshore hits record high – DRILL OR DROP?: https://drillordrop.com/2023/03/09/offshore-flaring-halves-in-four-years-but-onshore-hits-record-high/
- [17][18][21][22] UK offshore flaring and venting | IEEFA: https://ieefa.org/resources/uk-offshore-flaring-and-venting
- [23][24][25][34][35][36] Reliable sustainable management strategies for flare gas recovery: technical, environmental, modeling, and economic assessment: a comprehensive review: https://www.researchgate.net/publication/379693083*Reliable*sustainable*management*strategies*for*flare*gas*recovery*technical*environmental*modeling*and*economic*assessment*a*comprehensive_review
- [26][27][28][29][30][31][32][33] Associated Petroleum Gas | APG | Flare Gas: https://www.clarke-energy.com/us/applications/associated/
- [37][38][39][40][41][48][49][56] GTL: Small Scale and Modular Technologies for Gas to Liquid Industry - Oil & Gas Portal:

https://www.oil-gasportal.com/gtl-small-scale-and-modular-technologies-for-gas-to-liquid-industry/?print=print

- [57] Gas to liquids (GTL) microrefinery technologies: A review and …
 https://www.sciencedirect.com/science/article/pii/S0016236124015333
- [58] Zero Flaring Projects Deliver | FinancialTribune:
 https://financialtribune.com/articles/energy/99510/zero-flaring-projects-deliver

Chapter 3: Flare Gas Recovery Feasibility and Options Analysis

3.1 Field Overview – Geology, Reservoirs, Wells, and Artificial Lift

The Band‑e-Karkheh oil field is an elongated anticline structure with a NW–SE trend, situated within the Zagros Basin of southwest Iran. It is located in the Dezful Embayment region (Khuzestan province), near the city of Ahvaz and the giant Ahvaz oil field. The anticline measures approximately 60 km by 10 km and was initially identified through seismic surveys conducted in the 1960s. The first exploration well, BKH-1, was drilled in 1967, targeting the Oligo-Miocene "Asmari formation"; however, this well only encountered water in the "Asmari" reservoir.

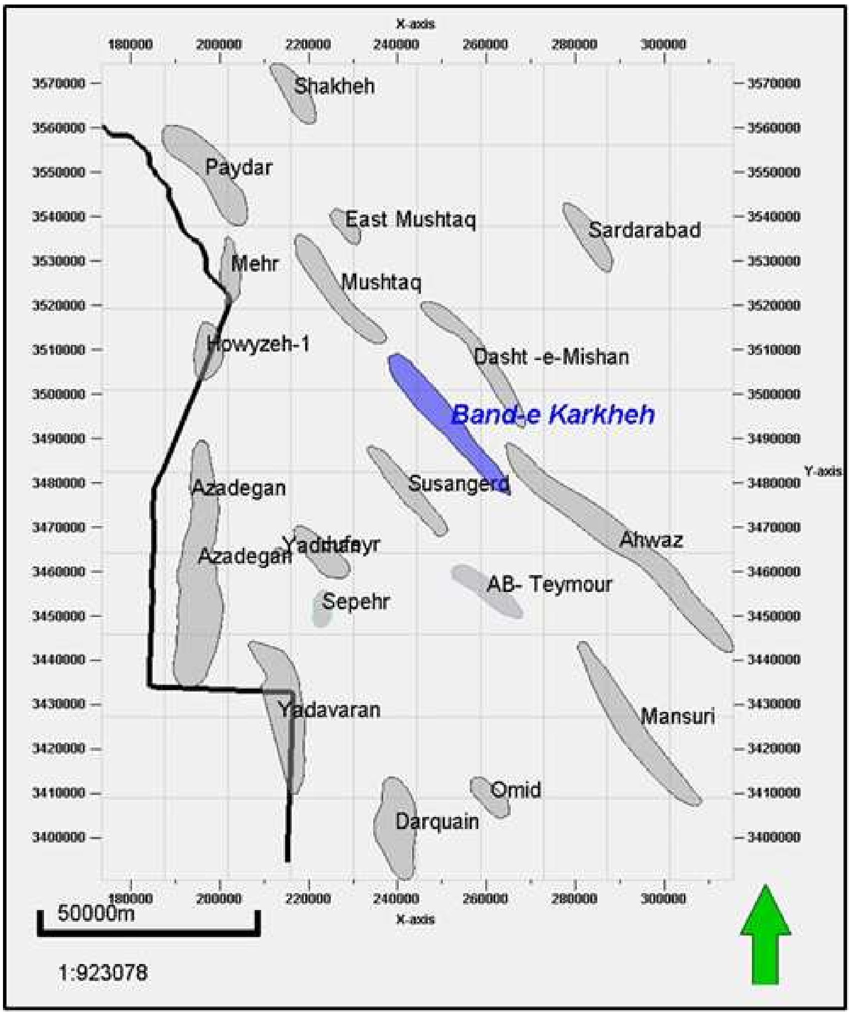


Figure 3‑1: Location map of Band-E-Karkheh Oil Field in Dezful Embayment

Subsequent exploration efforts in the 2000s successfully proved the existence of oil in deeper Cretaceous formations. The Band-e-Karkheh field was officially confirmed as an oil discovery in 2005 when well BKH-02 produced approximately 1,000 barrels of oil per day from the Ilam formation following acid stimulation. An additional appraisal well, BKH-04, encountered hydrocarbons in the Sarvak formation, but found mostly water in the Ilam formation at its northern location. These findings established the Upper Cretaceous Ilam formation as the primary reservoir, with the Sarvak formation holding additional potential. The oil from the Ilam reservoir is characterized as moderately heavy, with an API gravity of approximately 22°, and contains associated gas with minor levels of H_2S noted in test results.

Well NO.	Test No.	Date	Formation	Recovered Fluid
BKH-01	1	7/9/1967	Asmari	Water
	2	11/12/1967	Asmari	Water
BKH-02	1	21/12/2004	Lower Ilam-C	ormation Water with Traces of Oi
	2	28/12/2004	Ilam-C1	Oil + Water
	2a	3/1/2005	Ilam-C1	Oil + Minor Water
BKH-04	1	13/12/2007	Sarvak-E1	Limited oil
	1a	15/12/2007	Sarvak-E1	Limited oil
	2	29/12/2007	Sarvak-D, E1, E2	Oil
	2a	2/2/2008	Sarvak-D, E1, E2	Oil + Traces of Water
	3	17/02/2008	Ilam-C1	ormation Water with Traces of Oi
	4	29/02/2008	Gurpi	

Summary of DST data and interpretation are presented here:

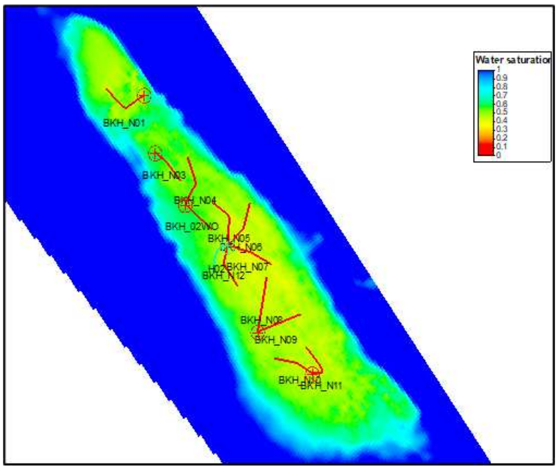
The field's development plan outlines a total of 14 wells, comprising:

- 12 horizontal oil producer wells targeting the Ilam reservoir.
- 1 produced water disposal well.
- 1 appraisal well for deeper targets.

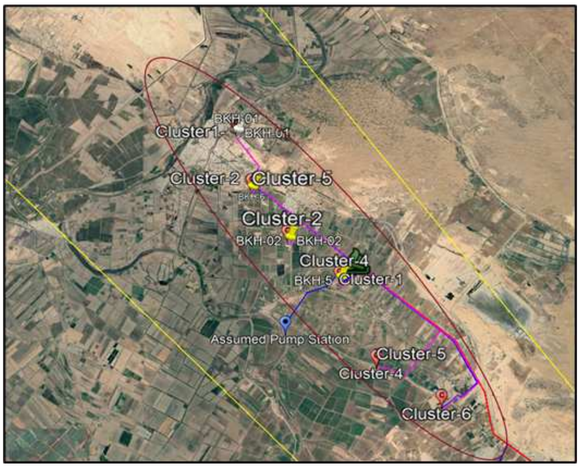
To minimize the surface footprint, given the field's proximity to farmland and settlements, production wells are arranged on clustered well pads. Each cluster is designed to host 3–4 wells, with a total of six clusters planned to gather production from all wells.

Artificial lift is a critical component of the field's production strategy. **Electric Submersible Pumps (ESPs)** are to be installed in all new producer wells to achieve sufficient drawdown and maintain target flow rates. The implementation of ESPs is necessitated by the reservoir's modest pressure and the oil's relatively high viscosity, which collectively inhibit sustained natural flow. The use of ESP lift is projected to enable the field to meet its production targets, which include an initial plateau of approximately 2,500 barrels per day from early wells, ramping up to a plateau of around 18,000 barrels per day by 2029 as additional wells come online.

In summary, the development of the **Band-e-Karkheh field** is centered on the Ilam reservoir, with production facilitated by horizontal wells equipped with ESPs and grouped on clusters. This production is then directed to a central facility for processing. The presence of associated gas, which is currently flared, presents an opportunity for beneficial utilization as detailed in this chapter.



Well Location of Ilam Reservoir



General layout of Band-E-Karkheh Field area

3.2 CPF Facilities and Power Demand

All produced fluids from the field's wells are gathered and processed at a Central Processing Facility (CPF), which is designed to separate oil, gas, and water. The CPF is a full-field facility that includes oil processing trains and various supporting systems. Produced water is treated and then sent via a dedicated pipeline to a disposal well located at cluster-6. Concurrently, a pilot water injection pipeline directs a portion of the treated water to an injection well at cluster-2 for enhanced oil recovery trials. The CPF is also equipped with a water supply line from the nearby Karkheh River to support operational needs such as cooling and injection preparation. Stabilized crude oil is exported from the CPF through a 35 km pipeline to the West Karoun Booster Station, where it connects to regional export infrastructure.

Initially, power for the CPF and its associated well pads was planned to be supplied by the national grid through an overhead transmission line from the West Karoun Power Plant’s substation. The electrical load of the Band-e-Karkheh facilities is substantial, driven primarily by the ESPs, surface pumps, compressors, processing equipment, and utilities.

- Peak Electrical Demand: Approximately 10 MW.
- Continuous Consumption: Estimated at 240 MWh per day (reflecting a base load of ~10 MW).
- Annual Consumption: Projected to be around 87,600 MWh (87.6 GWh).

Meeting this 10 MW requirement with grid power would result in significant operating costs and a dependency on external supply. Consequently, there is a strong motivation to utilize the field's own associated gas, which is currently flared, for on-site power generation. By recovering the flare gas and converting it into electricity, the field could achieve self-sufficiency in power, supplying the ~10 MW CPF load internally while simultaneously eliminating routine gas flaring.

Property	Value
Routine flare flow	~36 MMSCFD
HHV (volumetric)	~184 MJ/Sm³ (reported)
Wobbe Index	~103 MJ/Sm³ (reported)
Gas specific gravity (air=1)	~3.19 (reported)

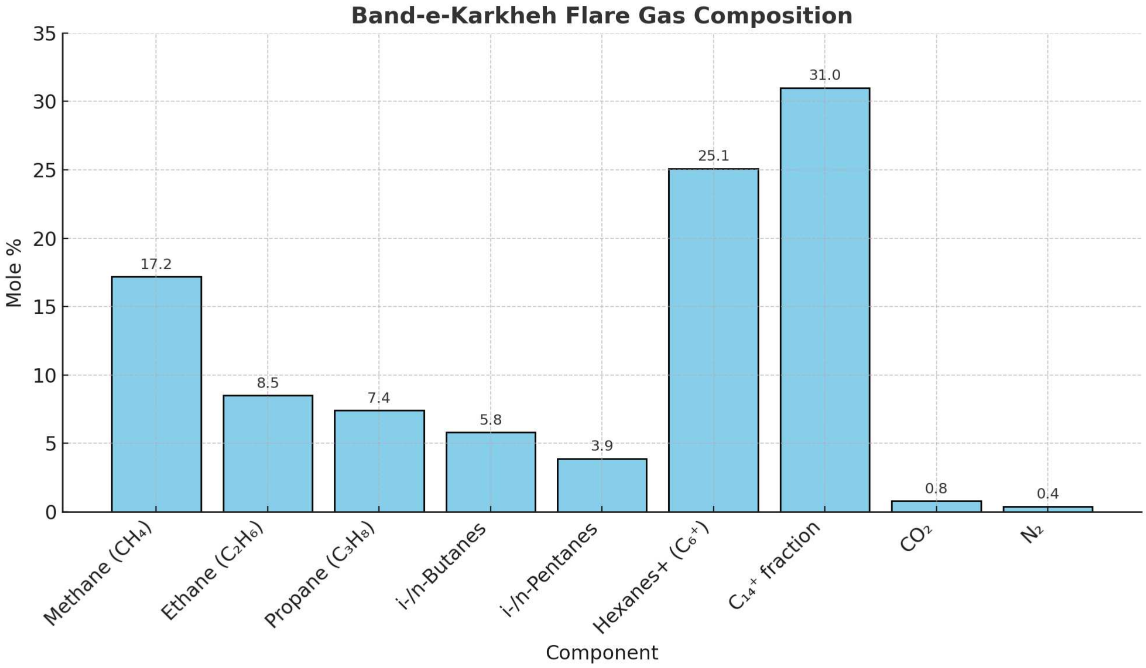
Metric	Value
Peak electrical load	~10 MW
Daily energy	~240 MWh/day

Flare-gas properties (design basis) and CPF electrical demand (design basis).

3.3 Flare Gas Volume and Composition

At present, the associated gas produced at “Band-e-Karkheh” is routinely flared at the CPF due to the absence of a gas export pipeline or a utilization system. The flared gas stream operates at a rate of approximately 36 MMSCFD (million standard cubic feet per day) under normal conditions, representing the combined associated gas output from all producing wells at full field capacity. The gas is characterized as a "wet" associated gas, being very rich in heavy hydrocarbons rather than a typical dry, methane-rich natural gas. It contains a significant fraction of pentanes, hexanes, and heavier components.

Component	Mole %
Methane (CH_4)	~17.2%
Ethane (C_2H_6)	~8.5%
Propane (C_3H_8)	~7.4%
i-/n-Butanes	~5.8%
i-/n-Pentanes	~3.9%
Hexanes+ (C_6^+)	~25.1%
C_{14}^+ fraction (heavy ends)	~31.0%
Carbon Dioxide (CO_2)	~0.8%
Nitrogen (N_2)	~0.4%



Flare Gas Composition of Band-e-Karkheh (Mole %)

As indicated in the table, over 56% of the gas consists of heavy hydrocarbons (C_6 and heavier), which imparts an exceptionally high energy content per volume. Key properties of the gas include:

- Higher Heating Value (HHV): Approximately 184 MJ/Sm³. For comparison, typical pipeline natural gas has an HHV of 35–40 MJ/Sm³.
- Wobbe Index: Extremely high at approximately 103 MJ/Sm³.
- Specific Gravity: High at approximately 3.2 (relative to air).
- Methane Number: Low, indicating a tendency to knock in engines due to the heavy ends.
- Inert Content: Very low (CO_2 <1%, N_2 <0.5%), making the entire stream virtually combustible.

This composition has significant implications for any recovery project. The gas is prone to condensing liquids when cooled, necessitating fuel gas conditioning, such as knock-out drums, to remove condensable liquids and ensure stable combustion in power generation equipment. Despite these challenges, the rich nature of the gas means that each unit volume can produce substantially more energy than typical natural gas.

3.4 Theoretical Power Potential of the Flared Gas

The 36 MMSCFD (≈1.019×10^6 Sm^3/day) flare stream contains far more thermal energy than the CPF requires. Even with conservative heating values, the available energy is in the hundreds of megawatts thermal. Therefore, this thesis treats 10 MW of plant power as a design target, not a resource limit: the system will use only the fuel required to meet CPF demand, and any surplus gas is managed via liquid recovery and/or future expansion (additional engines, CHP/ORC, export, or reinjection).

3.5 Flare Gas-to-Power Recovery Technologies Evaluated

Several technology options were considered for converting the flare gas into electricity. The primary candidates included:

- Simple Cycle Gas Turbines (open-cycle combustion turbine generators)
- Organic Rankine Cycle (ORC) systems
- Hybrid Gas Turbine + ORC Combined Cycle
- Reciprocating Gas Engines (stationary internal combustion engine generators)

Each option was evaluated based on its achievable efficiency, expected power output from the 36 MMSCFD gas stream, its ability to meet the 10 MW demand, and its suitability for the specific gas composition and field conditions.

3.5.1 Gas Turbine Option (Simple Cycle)

A simple-cycle gas turbine operates by burning fuel in a combustor to drive a generator via a high-speed turbine. This technology is well-established for power generation, particularly at medium to large scales. For this application, a turbine (or multiple units) sized for several megawatts was considered. The analysis assumed a thermal efficiency of approximately 35%, which is typical for small industrial gas turbines.

At this efficiency, the 36 MMSCFD flare gas stream could generate about 5,071 kW (5.07 MW) of electricity. This output, equivalent to 121.7 MWh per day, would meet only about 50.7% of the CPF's daily power requirement, falling significantly short of the 10 MW target.

Additional technical challenges for the gas turbine option include:

- High Fuel Gas Pressure Requirement: Combustion turbines typically require fuel gas pressure of 18–27 bar (260–400 psi). The Band-e-Karkheh flare gas is at a low pressure (near atmospheric), necessitating a large, multi-stage fuel gas compressor. This would add 5–10% to the plant capital cost and impose a parasitic load, reducing net efficiency by 2–3 percentage points.
- Rich Gas Composition: The heavy hydrocarbons in the fuel can lead to operational problems such as autoignition or deposition in the combustor and turbine hot sections. This would require an extensive fuel gas conditioning system, including cooling and separation of C_5^+ liquids.

Conclusion for Gas Turbine: This option was deemed suboptimal due to insufficient power output (≈5 MW) and significant infrastructure challenges related to high-pressure compression and fuel conditioning for the rich, low-methane gas.

3.5.2 Organic Rankine Cycle (ORC) Option

The Organic Rankine Cycle (ORC) generates electricity from a heat source by using an organic working fluid in a closed loop. ORC systems are commonly used to recover low-grade waste heat. For flare gas, an ORC could be used by either capturing heat from the flare's combustion or by using an external combustor. However, the efficiency of converting fuel heat to electricity with an ORC is relatively low.

The analysis assumed a thermal efficiency of approximately 12%, consistent with ORC recovery from low-grade waste heat. In principle, if the flare gas is burned in a dedicated high-temperature combustor, ORC efficiency could be considerably higher. However, in this case, such a configuration would overlap with conventional gas-turbine combined cycles, increasing complexity and cost. For the present study, the ORC option is conservatively represented with a 12% efficiency assumption.

At 12% efficiency, the 36 MMSCFD flare gas would yield only about 1,739 kW (1.74 MW) of electrical power. This output, corresponding to 41.7 MWh per day, would meet only 17% of the CPF's demand. While an ORC could use all the gas by capturing its combustion heat, the majority of the energy would be lost as low-grade heat. Furthermore, an ORC system alone does not eliminate flaring but rather replaces an open flare with a closed combustion heat exchanger.

Conclusion for ORC: The ORC-only approach was not selected due to its very low conversion efficiency (~12%) and its inability to meet the field's power requirements. It represents a high-complexity solution for minimal gain and is more suitable as a supplemental waste heat recovery method.

3.5.3 Hybrid Gas Turbine + ORC (Combined Cycle) Option

A hybrid approach combining a small gas turbine with an ORC bottoming cycle to recover exhaust heat was also evaluated. This configuration boosts overall efficiency by capturing waste heat from the gas turbine. With the gas turbine operating at ~35% efficiency and the ORC at ~12% efficiency, the combined effective efficiency was estimated to be around 47%.

The total power output from this hybrid system would be approximately 6,810 kW (6.81 MW), with the gas turbine contributing ~5,071 kW and the ORC adding ~1,739 kW. This corresponds to 163.4 MWh per day, meeting about 68% of the daily power demand. While this option would eliminate continuous flaring and significantly reduce reliance on grid power, it has notable disadvantages:

- High Capital Cost and Complexity: It combines two different technologies, increasing costs, complexity, and maintenance requirements.
- Inherited Turbine Challenges: The system would still require a high-pressure (≈20 bar) compression system for the fuel gas and extensive conditioning to handle the rich gas.

Conclusion for Hybrid GT+ORC: Despite its higher efficiency (~47%), the hybrid option was not chosen because its power output (~6.8 MW) was insufficient to meet the 10 MW demand, and it presented added complexity and cost from deploying dual technologies. Although the hybrid GT+ORC configuration achieved higher overall efficiency, its technical and operational complexity outweighed the potential gains. The system required dual control architectures, additional heat recovery units, and higher maintenance effort. These factors increase both the investment and operational costs, making the concept unsuitable for a medium-scale onshore oil field like Band-e-Karkheh, where reliability and simplicity are key priorities.

Furthermore, the hybrid setup still failed to meet the 10 MW power requirement, demonstrating that achieving high efficiency alone does not guarantee technical or economic feasibility. Therefore, attention shifted toward a more flexible, modular, and robust technology capable of operating with rich associated gas under varying conditions. The following section introduces the reciprocating gas engine option, which satisfies these needs and provides a practical solution for on-site power generation from recovered flare gas

3.5.4 Reciprocating Gas Engine Option

Reciprocating gas engine generators emerged as the preferred solution. This technology, which uses large gas-fired internal combustion engines to drive generators, is proven for distributed generation in oilfield applications. The design would involve installing multiple units to achieve a combined output of approximately 10 MW. Modern gas engines can achieve a thermal efficiency of 38–40%. The system would be designed to consume the necessary amount of gas to produce 10 MW, with any excess gas potentially bypassed to flare.

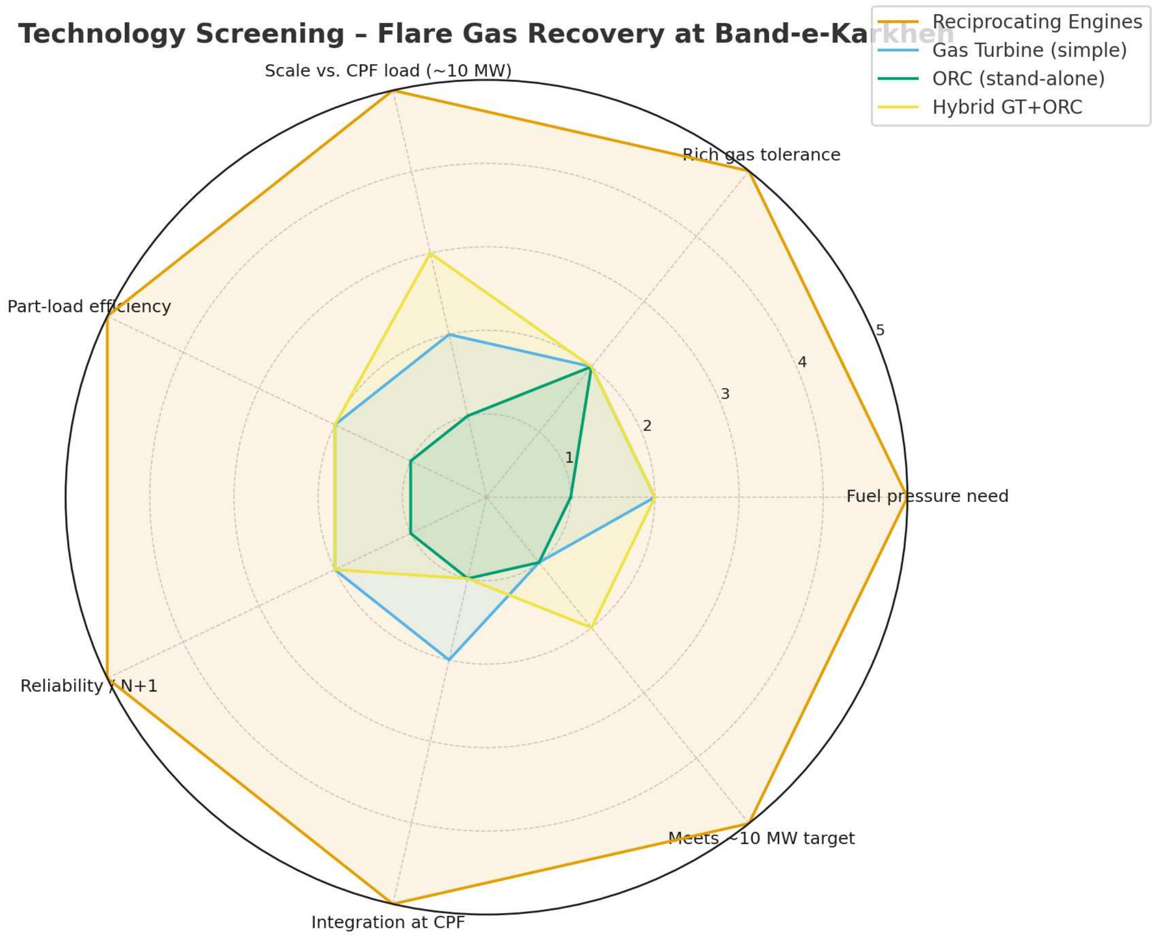
Key advantages of reciprocating engines in this application include:

- Ability to Fully Meet Power Demand: A suitably sized cluster of engine generators can supply the entire 10 MW load continuously, eliminating reliance on the grid for routine operations.
- Lower Fuel Gas Pressure Requirement: Gas engines operate at much lower intake pressures (4–5 barg) compared to turbines (18–27 bar). This simplifies the compression system, requiring only a dual-stage setup to raise the gas to ~5 bar.
- Tolerance for Rich Gas: Reciprocating engines are more flexible with fuel quality and can handle lower-methane, high-BTU gas with appropriate tuning and controls. Manufacturers offer engines specifically designed for high-calorific gas, which are more suitable for Band-e-Karkheh's gas composition than turbines.
- Higher Efficiency at Small Scale: In the 5–10 MW range, reciprocating engines typically exhibit better electrical efficiency than equivalently sized simple-cycle turbines.
- Modularity and Reliability: Using multiple units (e.g., five 2 MW units) provides redundancy, allowing for maintenance on one unit without a complete shutdown of power generation. Modern engines achieve high availability (90–95%).
- Operational Flexibility (Load Following): Reciprocating engines handle part-load operation more efficiently than turbines and can be cycled on or off incrementally to match power demand or gas availability.

Why Reciprocating Engines were Chosen:

- Reciprocating engines can meet the full 10 MW power demand.
- They require lower fuel gas pressure and are more tolerant of rich gas, which simplifies the gas conditioning and compression systems.
- They offer higher efficiency at this scale compared to other options.
- Their modular design provides reliability and operational flexibility.

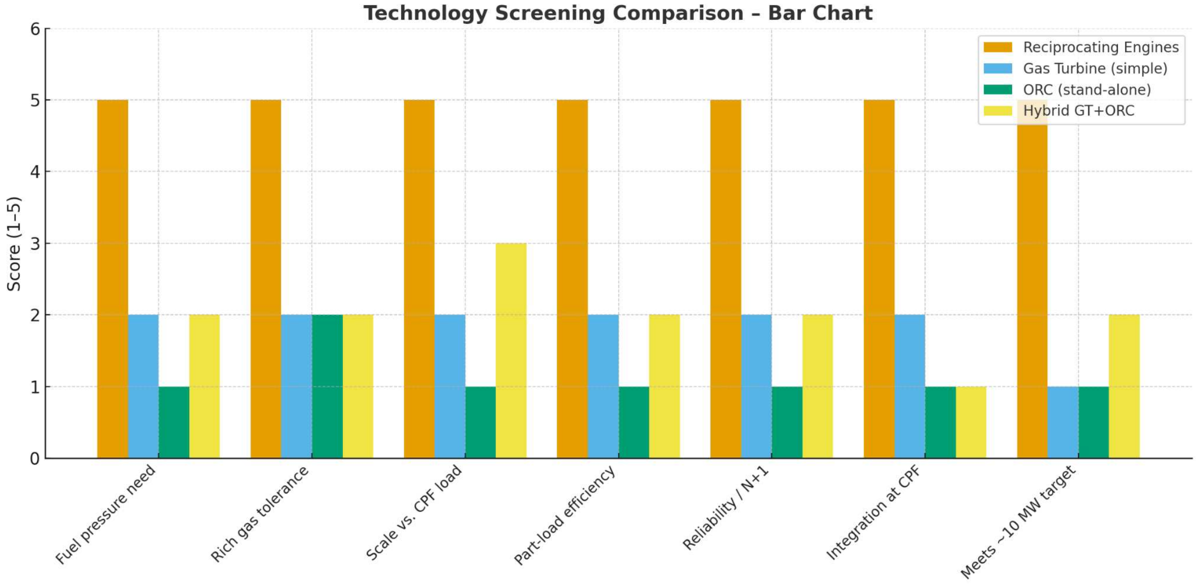
In contrast, gas turbines were rejected for insufficient output and high fuel pressure requirements, ORC for poor efficiency, and the hybrid GT+ORC for being overly complex while still failing to meet the full power demand. Reciprocating engine generators thus represent the most practical and effective solution for this project.



3.5.4 Wider Context: Energy Crisis in Iran and Strategic Fit of Reciprocating Engines

Iran is experiencing a persistent energy crisis, characterized by simultaneous shortages of natural gas supply in winter and electricity blackouts in summer. Despite having the world's second-largest proven natural gas reserves, rapid domestic demand growth, subsidized consumption, and aging infrastructure have led to seasonal shortfalls of up to 200 million m³/day in peak winter months. On the electricity side, demand growth outpaces grid expansion, and recurring blackouts affect both industry and households. Oil fields are not immune to these disruptions: CPF operations depend heavily on reliable power, and interruptions can cause safety risks, production losses, and equipment failures (especially for ESPs). In this context, self-sufficiency in power is strategically important for Iranian oil fields. By deploying reciprocating engines fueled by recovered flare gas, the Band-e-Karkheh CPF can insulate itself from grid instabilities and reduce dependency on external supply.

Criterion	Reciprocating Engines	Gas Turbine (simple)	ORC (stand-alone)	Hybrid GT+ORC
Fuel pressure needed	Low (~5 bar abs)	High (often >15–20 bar)	N/A (heat source)	High for GT stage
Rich gas tolerance	Good with de-rating; knock control possible	Limited at small scale; fuel conditioning often needed	Depends on heat source	Limited by GT stage
Scale vs. CPF load (~10 MW)	Good (multi-unit 3–5 MW modules)	Marginal at small scale for rich gas	Not primary mover	Modest gain over GT
Part-load efficiency	Good	Lower at small scale	N/A	Tied to GT part-load
Reliability / N+1	Excellent (multi-unit)	Single-train risk unless multiple GTs	N/A	Adds complexity
Integration at CPF	Straightforward	Higher compression + conditioning	Needs hot source	Highest complexity
Meets ~10 MW target	Yes (with multiple units)	No (per first-order)	No	No



3.6 Chapter Summary and Bridge to Chapter 4

An options analysis was conducted to evaluate four technologies for converting this flare gas into power: simple-cycle gas turbines, Organic Rankine Cycle (ORC) systems, a hybrid gas turbine (GT) and ORC system, and reciprocating gas engines. Through this screening process, reciprocating engines were identified as the preferred solution. This selection was based on their ability to fully meet the site's power demand, their higher efficiency at this scale, greater tolerance for the heavy gas composition, and lower infrastructure requirements compared to the other alternatives.

Having established the choice of technology, the next step is to detail the engineering design for implementation. Chapter 4 will present the detailed proposal for the flare gas recovery and power generation system at Band-e-Karkheh. It will cover the design basis, equipment configuration, and integration of the reciprocating engine solution, including the gas collection, compression, and treatment systems, the generator setup, and the electrical integration with the CPF. This will translate the rationale developed in this chapter into a concrete engineering design to capture the full 36 MMSCFD of flare gas and utilize it to produce ~10 MW of on-site electricity, thereby eliminating routine flaring and achieving energy self-sufficiency for the field.

Chapter 4: Engineering Proposal – Flare Gas Recovery and Power Generation

4.1 Introduction

The proposed configuration was developed in consultation with the expertise and design practices of MAPNA Group, the parent company in Iran, which has extensive experience in power generation and oilfield energy systems. This industrial input ensured that the proposed solution reflects practical considerations in addition to academic analysis.

In Chapter 3, several power generation options were evaluated for utilizing the flare gas: a simple-cycle gas turbine, an Organic Rankine Cycle (ORC) power unit, and a gas turbine + ORC hybrid. The findings showed that a single gas turbine (even after compressing the fuel to the ~25 bar required) could only produce on the order of 5 MW—barely half of the CPF's demand. An ORC system, which would generate power from the gas's heat (for example, by burning the gas in a waste-heat boiler), was even less efficient, yielding only about 1.7 MW (around 17% of demand). A combined system with a small gas turbine and an ORC bottoming cycle could reach roughly 6.8 MW (≈68% of demand)—better, but still insufficient to fully power the CPF.

Moreover, those alternatives presented practical challenges: small gas turbines require very high fuel pressure (often 20–30 bar), meaning a large compressor would be needed; they also struggle with rich, heavy fuels (risking burner instability and emissions issues due to the high C_6^+ content). Gas turbines generally suffer efficiency loss at partial loads and high ambient temperatures, both of which are concerns here (flaring volume can vary, and summer temperatures reach 50 °C). An ORC system alone, meanwhile, is complex and yields little power unless coupled with another cycle.

Given these considerations, the proposal in this chapter focuses on reciprocating gas engine generators as the optimal solution for flare gas recovery at Band-e-Karkheh. Reciprocating engines were chosen for several reasons:

- **Fuel Flexibility and Rich Gas Capability:** Spark-ignited gas engines can handle lower methane content and higher heavy hydrocarbon content better than turbines. The low Methane Number of the field gas (due to heavies) would severely challenge a turbine's combustion, whereas modern gas engines can be tuned or derated to manage knock. Engines only require a medium fuel pressure (~4–5 bar g), which is much easier to supply than the high pressures a turbine needs. This suits the Band-e-Karkheh gas, which is available at near-atmospheric pressure.
- **High Efficiency at Small Scale:** Reciprocating engines in the multi-megawatt class routinely achieve 35–40% electrical efficiency, even in smaller sizes. They maintain high efficiency over a wide load range, whereas a single gas turbine operating at part-load would see a sharp drop in efficiency. This means engines can economically follow the variable gas supply and load demand.

- **Modularity and Turndown:** Using multiple engine-generator units in parallel provides built-in redundancy and, if required, the ability to reduce output by shutting down individual units. This modular configuration is generally advantageous in projects where the flare-gas flow varies over time, allowing efficient operation even at partial load. However, at the Band-e-Karkheh CPF, both the gas flow and the power demand are relatively constant throughout the year. Therefore, this flexibility serves mainly as an operational safeguard rather than a routine requirement. The modular engine layout remains beneficial primarily for ensuring high reliability, simplified maintenance, and the possibility of future expansion..
- **Better Performance at High Ambient Temperatures:** Reciprocating engines are typically less sensitive to ambient temperature than gas turbines. Turbine output can fall ~15–20% on a 50 °C hot day (due to reduced air density), whereas engines (especially with turbochargers and intercoolers) might drop only ~5–10%. This is important in the Khuzestan climate (summers ~50 °C), ensuring more reliable power in peak summer when CPF power needs are highest.

For these reasons, the engineering proposal is to install a Flare Gas Recovery Unit (FGRU) feeding reciprocating gas engine generators totaling about 10 MW capacity. The following sections detail this design. Section 4.2 establishes the design basis and gives an overview of the system. Sections 4.3 and 4.4 discuss the gas collection and compression stages needed to get the low-pressure flare gas ready for use as engine fuel. Section 4.5 describes the reciprocating engine generators and their expected performance on this gas. Section 4.6 then covers how the system is integrated into the existing flare network and CPF electrical network, including control strategies for normal and emergency scenarios. Section 4.7 addresses various operational considerations and challenges (ambient conditions, flow variability, safety provisions, reliability). Finally, Sections 4.8 and 4.9 outline the assumptions/limitations of the study and recommendations for future improvements or further analysis.

Contribution of this work
Unlike previous flare gas recovery studies that emphasized gas turbines, ORC cycles, or hybrid GT+ORC configurations, this thesis demonstrates the feasibility of a reciprocating-engine-based solution for very rich, low-Methane-Number associated gas under extreme ambient conditions. The contribution is not only the subsystem design (KO drum, two-stage compression, engine block) but also the demonstration that reciprocating engines uniquely satisfy the 10 MW CPF demand at Band-e-Karkheh with acceptable efficiency and operability, while other technologies fail to do so. This positions the work as an academically novel case study and a practical design reference for flare gas recovery in heavy hydrocarbon fields.

Previous studies and field projects (reviewed in Chapter 2) have shown that gas turbines and ORC systems often underperform at small scales or when handling heavy associated gas streams. Chapter 3 confirmed that the Band-e-Karkheh flare gas is exceptionally rich in C_6^+ and C_{14}^+ fractions and that the CPF requires about 10 MW continuous power. This chapter therefore contributes by translating those general insights into a field-specific engineering proposal. The originality lies in adapting a reciprocating-engine–based FGRU to a heavy, high-BTU gas while explicitly quantifying parasitic loads and realistic fuel requirements — aspects that are often overlooked in the existing state-of-the-art studies.

4.2 Design Basis and System Overview

Design Target (Power): 10 MW net to the CPF at 50 °C ambient (~14 MW gross installed).
Parasitic Loads: Compression + auxiliaries ≈ 3 MW (summer worst-case).
Fuel Requirement (for 10 MW gross, $\eta_e \approx 40\%$): 0.4–2.0 MMSCFD depending on verified HHV after conditioning.
Front-End Flow Philosophy: Either (i) right-size compression/conditioning to the required fuel rate, or (ii) keep 36 MMSCFD front-end only if Phase-2 surplus utilization (NGL/extra engines/export) is planned.
Fuel Pressure to Engines: ~5 bara (≈4 barg).
Ambient: 10–50 °C; design summer case for drivers/coolers.

Energy Balance (design summary):
• Flare gas stream (basis): 36 MMSCFD = 1.019×10^6 Sm^3/day = 11.80 Sm^3/s.
• Engines sized for ~14 MW gross ($\eta_e \approx 0.40$) to deliver ~10 MW net after ~3 MW parasitics in summer.
• Fuel volume needed for 10 MW gross:
  — @ 39 MJ/Sm^3 → ~2.0 MMSCFD
  — @ 184 MJ/Sm^3 (as reported, to be verified) → ~0.42 MMSCFD
⇒ The front-end does not need 36 MMSCFD unless Phase-2 uses the surplus.

Parasitic Power Breakdown (Compression + Auxiliaries):
Nominal (25 °C): ~2.88 MW
Summer (50 °C): ~3.05 MW

Breakdown:
- Liquid-Ring Compressor (K-101 A/B): 0.25 MW (25 °C), 0.35 MW (50 °C)
- Seal-Water Pumps: 0.03 / 0.05 MW
- Centrifugal Booster (K-201 A/B): 2.20 / 2.60 MW
- Anti-surge Recycle Cooler Fans: 0.05 / 0.08 MW
- Intercooler Fans/Pumps: 0.12 / 0.18 MW
- Final Fuel-Gas Chiller: 0.10 / 0.15 MW
- Small Aux (controls, HVAC, lighting, pumps): ~0.25 / 0.30 MW

Subtotal – Compression: ~2.65 MW (25 °C), ~3.05 MW (50 °C)
Subtotal – Auxiliaries: ~0.23 MW (25 °C), ~0.28 MW (50 °C)
TOTAL: ~2.88 MW (25 °C), ~3.05 MW (50 °C)

The proposed system will recover the entire routine flare stream (up to ~36 MMSCFD) and use it as fuel to generate electricity on site. The target output is ~10 MW of electrical power, which will supply the CPF's consumption and thereby displace the need for any current grid or diesel power. By capturing and using the gas, continuous flaring is essentially eliminated during normal operations—the flare will remain in place only for emergency relief or as a small purge (fail-safe). Table 4.1 summarizes the key design parameters and assumptions for the system.

Parameter	Value / Assumption
Flared Gas Volume	~36 MMSCFD (1.02×10^6 Sm^3/day) – full routine rate
Gas Composition	Rich associated gas with very heavy ends (C_6^+ ≈25 mol%, C_{14}^+ ≈31 mol%). Negligible inerts (CO_2 <1%, N_2 <0.5%).
Gas Heating Value	~184 MJ/Sm^3 (HHV); Wobbe Index ~103 MJ/Sm^3 (extremely high due to heavies).
Site Power Demand	~10 MW peak (CPF consumption ≈240 MWh/day).
Power Generation	Reciprocating gas engine generators, ~10 MW total capacity (multiple units in parallel).
Compression Stages	Two-stage: (1) Liquid ring compressor(s) at near-atmospheric suction; (2) Centrifugal compressor(s) to boost to ~5 bar.
Fuel Gas Pressure	Engine inlet ~5 bar absolute (≈4 bar g). (Much lower than gas turbine requirements, simplifying compression.)
Gas Pre-treatment	Knockout drum + coalescing filter for full 36 MMSCFD flow to remove liquids/particles before compressors.
Tie-in Location	Connect at existing flare KO drum outlet, upstream of the flare's water seal (stack base).
Power Integration	10 MW of generators synchronized with CPF electrical network (island mode or grid-tied) to supply facility loads.
Site Conditions	Ambient temperature range: 10 °C (winter low) to 50 °C (summer high). Assume sufficient land and utilities (cooling water, etc.) are available as per development plan.

Table 4.1 – Key Design Parameters and Assumptions (Flare Gas Recovery and Power System)

In this design, a Flare Gas Recovery Unit (FGRU) will intercept the flare gas before it reaches the flare stack, compress and condition the gas, and then fuel on-site generators with it. The outcome is that gas which was previously being completely wasted by flaring is instead converted to ~10 MW of useful electricity, covering essentially 100% of the CPF's power requirements. Aside from the obvious fuel cost savings, this has a major environmental benefit: flaring ceases under normal conditions, eliminating the routine emissions and safety concerns of an open flare. It is important to note that the system is sized for normal operations—any emergency depressurization or upset that causes flaring above ~36 MMSCFD will still go to the existing flare as a safety measure. The flare remains in place as a backup for any excess gas that the recovery system cannot handle. No economic analysis (CAPEX/OPEX) is included in this chapter; the focus is purely on technical feasibility, design, and operational strategy.

Crucially, the Band-e-Karkheh gas properties drive many design decisions. The gas is extremely rich in heavy hydrocarbons (C_6^+ fractions form more than 56% of the gas by molar volume). This gives it a very high calorific value (HHV ~184 MJ/Sm^3) and a correspondingly high gas density (~3.3 kg/m^3 at 1 atm, 50 °C). Such a rich gas presents engineering challenges. Heavy hydrocarbons can condense into liquids if the gas is cooled or compressed improperly, and the fuel's low Methane Number indicates a strong propensity for engine knock (auto-ignition) in conventional gas engines. These issues are addressed through careful gas conditioning (knockout drums, cooling, and filtration to remove condensate) and by selecting appropriate engine technology (engines designed or derated for high-BTU gas). Key assumptions—for example, that the gas composition remains roughly as given and that suitably robust engines are available—are stated and examined later (Section 4.8). Overall, this proposal is presented with a rigorous, critical perspective: while the potential benefits (10 MW of power and near-elimination of flaring) are substantial, the practical challenges and uncertainties (gas behavior, equipment performance, etc.) are likewise significant and must be acknowledged in the design.

A simplified process schematic for the proposed system is shown in Figure 4.1. In essence, the FGRU will take a suction on the flare header, recover the gas through two stages of compression, and deliver it to a cluster of reciprocating engine-generators. The engines will produce power that is fed into the CPF's electrical distribution. The existing flare stack and knockout system remain in place as a parallel path that automatically handles any gas the recovery system cannot.

(Figure 4.1: Process schematic of a typical Flare Gas Recovery Unit, including a liquid ring compressor stage, gas/liquid separator, optional gas treatment, and engine generators. In the Band-e-Karkheh design, an amine sweetening unit is optional (dotted) if needed for H_2S removal. The flare stack and seal provide a passive safety bypass.)

4.3 Flare Gas Collection and Pre-Treatment

4.3.1 Flare Header Tie-In and Knockout Drum

The flare gas recovery system is connected to the existing flare header between the production separators and the flare stack—specifically, downstream of the production units' outlets and the main flare knock-out (KO) drum, but upstream of the flare's water seal and stack inlet. This ensures the FGRU intercepts the continuous flare gas without compromising the flare's primary safety role. Under normal conditions, instead of the gas flowing to the flare tip to be burned, it will be diverted into the recovery system. Importantly, the existing flare KO)drum at the base of the flare stack (or a new dedicated KO drum, if the existing one is insufficient) is utilized to remove bulk liquids (condensate and any water) from the gas stream before it enters the compressors. Any liquids in the gas—which are likely given the heavy composition—are knocked out by gravity in this vessel. The KO drum is sized to handle the full 36 MMSCFD flow plus any surges of liquid. A conservative sizing criterion is used: a superficial gas velocity on the order of 0.1 m/s inside the vessel, which allows droplets of ~300 µm and larger to settle out. Given the enormous flow rate, this results in a very large vertical vessel (on the order of several meters in diameter and height) to provide sufficient residence time and disengagement area. Such a vessel size is feasible on site (adequate plot space is assumed) and is warranted to prevent liquid carryover. The KO drum is equipped with level instrumentation and automatic drains to continuously remove the separated condensate. Collected liquids (which may be hydrocarbon condensate and some water) can be routed to the existing production facilities (e.g. sent to a condensate stabilization unit or slop tank) so that valuable liquids are recovered and not re-flared.

Downstream of the KO drum, a high-efficiency coalescing filter is installed as a polishing step (Figure 4.1, item 5). This coalescer captures any fine mist or aerosol droplets that escaped the KO drum, and it also removes any solid particles (rust, dust) in the gas. The coalescer is a large filter vessel containing multi-layer elements (fiberglass or stainless mesh) designed for the full gas flow (36 MMSCFD) with minimal pressure drop. It coalesces tiny droplets into larger ones which then drop out. An automatic drain is included to periodically purge liquids from the coalescer. After this stage, the gas can be considered essentially "dry" (free of liquid droplets) and clean, which is critical before compression. Even a small amount of liquid carryover could damage the high-speed centrifugal compressor impellers or cause issues in the engines (such as inducing knock or misfire), so the combination of a KO drum for bulk separation and a coalescing filter for fine separation is adopted, given the gas's very heavy nature.

At this point, the gas is at very low pressure (approximately atmospheric pressure, since the flare header normally operates near 0 barg). The FGRU suction line will draw from the KO drum outlet. One important integration detail is maintaining the flare's safety function: the flare system includes a water seal drum at the base of the stack, which provides a liquid barrier to prevent flashback up the stack. This seal also imposes a slight back-pressure on the header (typically equivalent to a column of water, e.g. ~750 mm or about 0.07 bar). The FGRU will be controlled to keep the header pressure just below the seal's lift pressure, so that under normal conditions all gas goes into the recovery unit.

If the FGRU is offline or the flow rate exceeds capacity, the header pressure will rise and automatically push gas through the water seal to the flare stack. In this way, the flare becomes a passive bypass: whenever the recovery system cannot handle the gas, flaring simply continues as a safety relief. This inherent arrangement guarantees that the FGRU cannot over-suck the system into a vacuum (which would risk air ingress) nor over-pressurize the header (since excess just goes out the flare). The control system will monitor header pressure and modulate the FGRU accordingly, but the water seal provides a fail-safe, hands-off mode of bypass. In summary, the gas collection design ties into the existing flare line and never compromises safety—in any upset or emergency, the gas will go to flare just as it does today.

Having intercepted and pre-treated the gas to remove liquids, the next steps are to compress the low-pressure gas and generate power from it. These are described in Sections 4.4 and 4.5. In overview, the compression system will consist of a two-stage compressor setup: first a liquid-ring compressor (to take suction from near 0 barg and give a modest boost), and then a centrifugal compressor (to raise pressure to ~5 bar for the engines). After compression and cooling, the gas will feed a cluster of engine-generators.

(Refer back to Figure 4.1 for a schematic flow of these stages: gas is drawn from the flare header (1) into the liquid ring compressor (2) along with seal water; the mixture is separated in a knock-out vessel (4) with demister (removing condensed liquids); the gas is then compressed in a centrifugal booster, cooled, and sent to the engines. The water seal at the flare (not shown in detail in Fig 4.1) ensures any excess gas goes to the flare.)

4.4 Compression System Design

To utilize the recovered low-pressure gas in the engines, it must be compressed to the required fuel supply pressure—on the order of 4–5 bar gauge (about 5–6 bar absolute) as specified for typical gas engines. The compression is accomplished in two stages: first, a liquid ring compressor handles the near-atmospheric suction from the flare header; second, a centrifugal compressor (with multiple impellers or stages) boosts the gas to the engine inlet pressure. This two-stage approach is chosen to manage the large volume and deep overall pressure ratio (~5:1) needed, while also safely handling the wet, heavy gas. Each stage is described below.

4.4.1 Liquid Ring Compressor (Low-Pressure Stage)
A liquid ring compressor (LRC) is selected as the first stage of compression. Liquid ring compressors are especially suited for vapor recovery from flare systems because they can handle saturated gas, vapor–liquid mixtures, and even small liquid slugs without damage. In a liquid ring machine, a rotor spins a sealing liquid (usually water) in an eccentric chamber, forming a “liquid ring” that traps gas pockets and compresses them. The key advantages of LRCs in this service are:

1. **Tolerance to liquids and contaminants** – the water ring absorbs heat of compression and can ingest small liquid carryover or condensate without harm (no metal-to-metal contact internals), unlike a dry gas compressor.
2. **Safe operation with flammable gas** – the near-isothermal compression (due to the water’s cooling effect) and lack of sparks or hot spots greatly reduce risk of ignition within the compressor.
3. **Ability to provide a modest suction vacuum** – an LRC can draw the flare header slightly below atmospheric pressure if needed to “pull” gas, maximizing recovery of low-pressure gas.

These features make LRCs standard in many flare gas recovery systems as the first stage.

In our design, one or more LRC units will take suction from the flare header (downstream of the KO drum and coalescer) at roughly 0 to +0.05 bar gauge (essentially atmospheric pressure). They will compress the gas to only a few hundred millibars above atmospheric. A single-stage LRC typically can deliver discharge pressures on the order of 1.2 -- 1.5 bar absolute (0.2 -- 0.5 bar gauge) for high flow rates. For Band-e-Karkheh, assuming the LRC raises the gas to about ~1.3 bars (~0.3 barg). This is a modest pressure boost but is very valuable: it elevates the gas above 1 atm so that it can flow through downstream equipment and into the next compressor, and it reduces the specific volume of the gas (by ~20–25%) which helps size the downstream stages. Because the total flow rate is enormous (36 MMSCFD is ~1.0×10^6 Sm³/day, or ~42,000 Sm³/hour), multiple LRC units in parallel will likely be required. For example, three liquid ring compressors each sized for ~50% of the flow (two running, one as hot spare) could be installed, or four smaller units at ~33% each for more flexibility. Parallel units not only handle the throughput but also provide redundancy—one unit can be out for maintenance while the others manage a reduced flow—and turndown capability (one or more units can be turned off during low flaring periods to avoid running a single large unit at very low load). Each LRC skid will have an electric motor driver (using a small fraction of the generated power to run—effectively a parasitic load). The compressors would share a common suction header from the KO drum and discharge into a common manifold leading to the next stage.

Each LRC unit has an associated seal liquid system: water is continuously circulated from a separator vessel, through a cooler, and back to the compressor (with makeup water added to compensate for losses). In our design, the discharge of the LRC flows into a dedicated gas-liquid separator (knockout vessel) where the two phases are disengaged by gravity and a demister pad. This separator (shown as item 4 in Fig 4.1) serves multiple purposes: it removes the entrained water from the gas, it knocks out any additional condensate that may have formed during the near-isothermal compression (the gas will cool to ~30 °C or so, potentially condensing some heavy C_6^+), and it acts as the reservoir for the seal water. Inside the separator, a mist eliminator ensures essentially all water drops fall out. The separated water collects in the bottom and is pumped through a heat exchanger to remove the heat of compression, then returned to the LRC. A makeup water source is provided to keep the liquid ring full (compensating any water that goes out with the gas or drains). Separated hydrocarbon condensate is also collected at the separator and periodically drained to the condensate recovery system—given the rich gas, this could be a non-trivial liquid volume (e.g. if the gas enters at 50 °C and is cooled to 30 °C in the LRC, substantial heavy ends may drop out). Any dissolved acid gas (H_2S, CO_2) that comes out of solution in the seal water will be vented from the separator (ideally back to the flare header or a safe location). In summary, the LRC stage acts as a vapor recovery unit that gently takes in the flare gas at ~0 barg, compresses it to ~0.3 barg, and removes the bulk of liquids and heat in the process.

Despite being near-isothermal, the liquid ring compressor will consume a significant amount of power because of the huge volumetric flow. Based on preliminary estimates, each LRC might require on the order of several hundred kilowatts of shaft power to move the gas. If multiple LRCs are running, the total power for the LRC stage could be around 0.5–1.0 MW. A simplified ideal calculation (treating compression as isothermal) indicates roughly 0.25 MW needed at winter conditions (10 °C) and up to ~0.30 MW at summer conditions (50 °C) for the entire LRC stage at full flow. (Hot gas is less dense, so the compressors must move more volume for the same mass flow, hence slightly higher power in summer.) In practice, it will size the motors a bit larger (to account for inefficiencies and margins), but these figures show that the LRCs will use a noticeable chunk of the generated power. This **parasitic load** will effectively reduce the net power delivered to the CPF by that amount. However, tolerating this internal power use is necessary to recover the gas—we will see later that even after these losses, the net power gain is still worthwhile. The LRC stage's ability to handle wet gas safely outweighs its power draw. (For context, many flare recovery projects report LRC power in the few hundred kW range per machine, which aligns with our expectation here.) All LRC components (compressor internals, separator, piping) will be made of appropriate materials (stainless steel or coated carbon steel) to resist any corrosion from H_2S or CO_2 in the wet gas.

4.4.2 High-Pressure Centrifugal Compressor (Booster Stage)

After the first-stage separator, the gas—now at ~1.3 bara and near ambient temperature, and essentially free of liquids—enters the high-pressure compression stage. The role of this stage is to boost the gas to the engine fuel pressure of about 5 bar absolute (~4 bar gauge). We propose using a centrifugal compressor (turbocompressor) for this duty, likely a multistage centrifugal package given the required pressure ratio of ~4:1. Centrifugal compressors are well suited for large volumetric flow rates, offering continuous flow and high reliability with minimal maintenance (no pistons or valves). However, a single centrifugal impeller cannot usually achieve a 4:1 pressure increase in one step, so a two-stage configuration with intercooling is anticipated. For example, one could employ a compressor with two impellers in the same casing (or two casings): Stage 1 compresses from ~1.3 bara to ~2.5 bara; then an intercooler removes heat (and condenses any heavy hydrocarbons that might drop out upon cooling); Stage 2 compresses from ~2.5 to ~5 bar_a. After the final stage, an after-cooler reduces the gas temperature back to near-ambient (≈30–40 °C) before it goes to the engines. At each cooling step, a small knockout pot is installed to collect any newly condensed liquids. By this point, liquid condensation should be minimal (most was removed in the LRC stage), but given the heavy gas, even a few droplets coming out in the intercooler is possible. Those KO pots will have auto-drains tied into the condensate collection system.

A two-stage centrifugal booster with intercooling is preferred to limit discharge temperatures and prevent hydrocarbon condensation in the heavy C_6^+/C_{14}^+ stream. Under summer design conditions (≈50 °C inlet), a single 1.3→5.0 bar(a) step yields an ideal discharge near 150 °C by increasing dew-point proximity after cooling and tightening materials constraints. Dividing the overall ratio maintains per-stage discharge near 95–110 °C, enables interstage liquid knock-out, and improves polytropic efficiency and surge margin over variable flare rates. Intercooling reduces specific work and cooler duty, and the staged configuration provides greater operational robustness at high ambient while delivering the same final fuel pressure.

The design discharge pressure is ~5 bara (about 4 barg) based on typical requirements of modern gas engines (Wärtsilä, for example, specifies around 4–5 bar inlet pressure for their large gas engines). Supplying fuel at this pressure is a major advantage over gas turbines, which often need 20–30 bar and thus much more compression. It will be confirmed the exact required pressure with the engine manufacturer and include some margin (perhaps design for 6 bara) to account for pressure drops and to ensure flexibility. The goal, however, is not to over-compress unnecessarily—compressing higher than needed would waste energy.

Capacity and Power Requirements: The centrifugal compressor(s) must handle roughly 36 MMSCFD of gas at the suction conditions of ~1.3 bar_a, ~30 °C (after LRC). In mass flow terms, that is on the order of 40–45 kg/s of gas (depending on composition and temperature). Raising this flow to 5 bars will require a substantial amount of work. A rough adiabatic compression calculation (assuming an average specific heat ratio k ≈1.25 for the heavy gas) suggests on the order of 2.0 -- 2.5 MW of shaft power is needed for the booster stage. This assumes an intermediate ambient condition (~30 °C); it is a first estimate for sizing. To put this in perspective, if ~2.5 MW is needed for the centrifugal and ~0.5–1 MW for the LRCs, then about 3 -- 3.5 MW of the generated power would be consumed internally by compression. That leaves on the order of ~7 MW net available to the CPF. (This net outcome will be revisited later, but even ~7 MW would cover 70% of the CPF's needs, which is still a large improvement, and essentially all the power would be produced from otherwise wasted gas.)

It is important to evaluate the compression power at the extremes of ambient temperature as well. In the peak summer (50 °C), the gas is less dense, so for the same mass flow the compressor must move a larger volume—this makes the compressor work harder. At 50 °C, the shaft power could rise to around ~4.0–4.4 MW to maintain 36 MMSCFD throughput. Conversely, in winter (10 °C), the gas is denser and the volumetric flow is less, so the compressor might only require on the order of ~3.1 MW to achieve the same mass flow. (These figures assume the compressor runs at full capacity; in reality, if less gas is coming in during winter, the power would be lower due to lower flow as well.) It will size the electric motor and drive for the worst case (summer full flow), i.e. roughly a 5 MW motor to have a comfortable margin. The result is that the centrifugal compressor is a major consumer of power—roughly one-third to nearly one-half of the gross power output of the engines, depending on conditions. This underscores why choosing reciprocating engines (with their lower fuel pressure requirement) was important; a gas turbine scenario would have needed an even larger compressor consuming possibly 5–6 MW just to get 20–30 bar fuel, leaving little net power.

Given the very large flow, its likely to use two centrifugal compressor trains in parallel (each 50% capacity). This mirrors the LRC setup and provides redundancy: for example, two smaller centrifugal machines each sized for ~18 MMSCFD. In normal operation they both run and share the load; if one trips, the other can still compress about half the gas (the rest would go to flare temporarily). The parallel arrangement also helps with turndown—one machine can be taken offline during periods of sustained low flaring (instead of running both at low efficiency). Each centrifugal compressor will be driven by a large electric motor (again powered by the generators themselves).It will be included a recycle (spillback) line with an anti-surge control valve on each compressor: this loops from the discharge back to the suction drum, allowing the compressor to circulate flow and avoid surge when the inlet flow is below the stable operating limit. Anti-surge control is critical, as the flare gas flow can fluctuate and must be protected the compressor from going into surge (which could damage it). The intercooler(s) will have their own cooling water circuits or air-cooled exchangers to remove the heat of compression. All equipment in contact with the gas will be specified for H_2S service (NACE compliant materials if needed) since its suspected some H_2S is present (even if <0.1%, it's prudent to design for sour gas).

In summary, the compression system consists of a robust liquid ring stage that first safely recovers and de-liquefies the flare gas, followed by an efficient centrifugal stage that delivers the pressure needed for power generation. Together, these compressors prepare the gas for use in the engines, albeit at the cost of some power. The total compression power requirement (roughly 3–4 MW) will directly subtract from the engines' gross output, as it is supplied by the generators. This is an inherent trade-off in any gas recovery scheme—some energy must be invested to save the rest. In our case, if ~10 MW gross is produced and ~3 MW drives the compressors, ~7 MW net is exported as useful power (the remainder is still a huge gain, and it replaces diesel or grid power that would otherwise be needed). It will revisit this energy balance in the results (Section 4.10). The important point is that the compressors are properly designed to handle the wet, heavy gas (the LRC making it safe, the centrifugal providing the muscle) and include the necessary controls (anti-surge, parallel operation) to handle the variable flow conditions expected.

(Materials note: both LRC and centrifugal compressors, including coolers and separators, will be constructed of materials suitable for wet hydrocarbon gas with potential H_2S. Likely 316 SS or carbon steel with corrosion allowance and coating will be used. If H_2S content is significant (to be confirmed by gas analysis), an amine gas sweetening unit could be added after compression to

remove H_2S, but for this proposal it is assumed H_2S is low enough to be burned in the engines or handled by a simpler scavenger, to avoid complicating the system.)

4.5 Reciprocating Gas Engines for Power Generation

4.5.1 Modular Configuration

Rather than a single large generator, multiple moderate-sized reciprocating gas engines are proposed to reach the ~10 MW requirement of the CPF. This modular approach provides redundancy, flexibility, and maintainability. A typical arrangement would employ three engines each rated ~3.3 MW, operating at ~80–90% load to collectively deliver ~10 MW gross. Alternatively, four engines rated ~2.5–3 MW could be used, with three covering the continuous demand and the fourth reserved as a spare (N+1 configuration).

Using multiple engine-generator units in parallel offers built-in redundancy and the ability to adjust capacity by shutting some units down during periods of reduced gas availability. This characteristic is advantageous in projects where flare volumes vary significantly, as it allows efficient part-load operation. However, in the case of the Band-e-Karkheh CPF, both the flare gas supply and the electrical load are relatively constant throughout the year. Therefore, load-following flexibility is a secondary benefit rather than the main selection criterion.

The modular configuration is primarily justified by its reliability and maintainability advantages. With several engines operating in parallel, the system can continue to supply critical power even if one unit is taken offline for maintenance or experiences an unplanned trip. This N+1 philosophy—having one additional unit beyond the minimum required for the peak load—is standard practice in oilfield power systems and greatly enhances operational availability (see Section 4.7). Moreover, the modular arrangement simplifies future expansion if CPF power demand increases or if grid export is introduced in later phases.

The decisive technical reasons for adopting reciprocating engines are their high efficiency at small scale, their tolerance to rich, low-Methane-Number gas, and their compatibility with the moderate fuel pressure (~5 bar_a) produced by the compression system. These characteristics make them more suitable than small turbines or ORC systems for the Band-e-Karkheh site conditions.

4.5.2 Candidate Engine Families

Several European OEMs offer engines in the 2–5 MW range suitable for flare gas and associated gas applications:

- GE Jenbacher J620 (Austria) – 3.1–3.4 MW per unit; strong track record on high-BTU and associated gases; robust knock control via per-cylinder monitoring and ignition timing adjustment.
- MWM TCG 2032B V16 (Germany) – 4.0–4.5 MW per unit; high efficiency, proven in difficult gas applications, broad service network.
- Wärtsilä 34SG / 31SG (Finland) – large-bore engines rated ~7–10 MW per unit; highest efficiency, but oversized for a 10 MW Phase-1 unless a single-unit configuration is acceptable.
- Siemens-Energy / Guascor SGE56 (Spain) – 1.5–2.0 MW per unit; tolerant of variable fuel quality; would require 5–7 units to achieve 10 MW, increasing auxiliaries and O&M complexity.

4.5.3 Selection Criteria

The following criteria were considered in choosing the most appropriate prime mover:

1. Fuel tolerance – The Band-e-Karkheh gas is rich in C_6^+ and C_{14}^+ fractions, implying a low Methane Number (MN) and high knock tendency. Engines must tolerate MN < 40 with derating and knock detection.
2. Fuel pressure compatibility – The compression system (Section 4.4) is designed to deliver ~5 bar_a at the engine inlet; engines requiring higher pressures would demand additional compression.
3. Modularity and N+1 availability – Ability to achieve ~10 MW gross with 3–4 units, avoiding reliance on a single large unit.
4. Efficiency and derate performance – Ability to maintain ≥38% efficiency (LHV basis) and operate reliably under hot ambient conditions (50 °C).
5. Vendor track record – Proven references for associated-gas and flare-gas projects in climates similar to Khuzestan.

4.5.4 Recommended Prime Movers

Based on the above criteria, the GE Jenbacher J620 (Type F/H, 50 Hz, associated-gas configuration) is recommended as the primary choice for Phase-1.

- Configuration: 3 × J620 units, each ~3.3 MW ISO, providing ~9.9 MW gross.
- Site rating: ~9.0–9.5 MW gross at 50 °C, accounting for 5–10% derate.
- Efficiency: 38–41% (LHV basis) under associated-gas tuning; assume 38–40% for design.
- Fuel requirement: ~7,200–9,900 Sm^3/h total for 10 MW, depending on final LHV.
- Knock control: Cylinder pressure sensors with ignition retard capability; optional compression ratio variants.
- Emissions: Lean-burn configuration with oxidation catalyst; space reserved for SCR if required.
- Fuel pressure requirement: 4–5 bar_g, fully aligned with the centrifugal booster specification.

Qualified alternates include the MWM TCG 2032B V16, which offers comparable performance and efficiency, and the Wärtsilä 34SG, which may be preferable for Phase-2 expansion if capacity is increased beyond 10 MW.

4.5.6 Ambient Effects and Reliability

At high ambient temperatures (50 °C), power output is expected to fall by ~5–10% due to reduced air density. With three J620 engines, this corresponds to ~9.0–9.5 MW gross available, which still meets CPF demand. At low ambient (10 °C), minor over-performance is possible, but engines are capped at nameplate rating. Additional precautions include KO pots, insulation, and heat tracing of fuel lines to prevent condensation of heavy hydrocarbons in winter.

The N+1 modular design ensures that the CPF retains partial power supply if one engine is unavailable. This configuration therefore balances technical feasibility, reliability, and alignment with site conditions, while preserving expandability for future capacity increases or export scenarios.

Criterion	GE Jenbacher J620	MWM TCG 2032B V16	Wärtsilä 34SG / 31SG	Guascor SGE56
Unit Rating (ISO)	3.1–3.4 MW_e	4.0–4.5 MW_e	7–10 MW_e	1.5–2.0 MW_e
Fuel Pressure Requirement	4–5 bar_g	3–5 bar_g	4–5 bar_g	3–5 bar_g
Suitability for Low-MN Gas	High – associated-gas/landfill packages available; strong knock control	High – proven APG projects; derating possible	Moderate–High – best with pretreated fuel; strong knock control but assumes leaner gas	Medium – robust but designed for biogas and landfill gases
Efficiency (LHV basis)	38–41%	39–42%	42–45% (highest)	35–38%
Modularity for ~10 MW	Excellent: 3 × 3.3 MW	Good: 3 × 3.3 MW or 4 × 2.5 MW	Poor for Phase-1 (single large unit ~8–10 MW)	Good: 5–7 × 1.5–2.0 MW
Redundancy (N+1)	Yes, 3 units	Yes, 3–4 units	Limited, 1 unit only	Yes, multiple units
Ambient Derating (50 °C)	5–10%	5–10%	5–10%	5–10%
Track Record (Associated Gas)	Strong global references	Strong global references	Good, but usually on pipeline-quality NG	Good, esp. for biogas & flare
Complexity / O&M	Moderate	Moderate	Higher (larger auxiliaries, balance-of-plant)	Higher (more units, more auxiliaries)
Overall Suitability (Phase-1)	**Best fit**	Close 2nd	Suitable for Phase-2 expansion	Acceptable, less efficient

SOURCE:https://www.jenbacher.com/it/novita-media/download/schede-informative/scheda-tecnica-motore-serie-6-italiano

4.6 System Integration and Control Strategy

Integrating the flare gas recovery system with the existing flare network and the CPF's operations requires a careful control strategy to ensure seamless operation across all conditions (normal run, low flaring, high flaring, start-up, shutdown, and emergencies). The guiding principle is that the FGRU must not interfere with the primary safety function of the flare—at any time, the flare must be able to take the full flow if needed. Thus, the system is designed such that the flare is always a ready and open path. The FGRU effectively "pulls" gas when it can, but if it ever cannot, the gas simply goes to the flare. Key aspects of this integration and control are described below.

4.6.1 Tie-in and Header Pressure Control

As noted, the FGRU suction is connected between the existing flare KO drum and the flare's water seal. Under normal operation, an automatic suction control valve on the FGRU line is open to allow gas flow into the compressors. The header pressure is maintained at a slight positive value (approximately the water seal pressure, ~0.07 barg). The FGRU's control system modulates compressor capacity (or a throttle valve) to hold the header at this set-point. If the FGRU tends to draw too hard (pressure dropping towards 0 or vacuum), the control will throttle back or recycle gas to raise the pressure. If the gas coming into the header increases and pressure begins to rise above ~0.07 barg, it means the FGRU is not taking all of it—at that point, the water seal will "lift" and excess gas will automatically go to the flare stack to be burned. In essence, the water seal serves as a self-acting back-pressure regulator: it prevents the header from exceeding ~0.07 bar by venting gas to the flare. The control system will sense this as well (high header pressure) and can if possible ramp up compressors, but if capacity is maxed out, it simply lets the flare take the overflow. This passive scheme ensures there is no complex switchover needed—the flare and FGRU operate in parallel, with the seal directing flow as needed. Under normal steady conditions, header pressure might be maintained just below the seal cracking point, meaning essentially all gas goes to FGRU.

4.6.2 Flare Bypass in Emergencies

In an emergency flaring event (for example, a process upset that suddenly dumps a large quantity of gas to the flare header, far above 36 MMSCFD), the FGRU will not attempt to handle it—by design, the excess will immediately lift the water seal and divert to the flare. The header pressure will spike, the FGRU will detect this and likely trip off (high-high pressure shutdown to protect compressors), and the flare will take the full flow. Even if the FGRU did not trip, it cannot increase capacity to those levels, so the bulk of gas would go out the flare anyway. This design philosophy ensures that safety always overrides recovery. The flare is always the ultimate relief path. Once the emergency is over and flows return to normal, the FGRU can be re-started to resume capturing gas. No intervention is required for the handover; it is governed by physics and simple controls.

At the opposite extreme, when flaring is minimal—such as during periods of reduced oil production or gas diversion for reinjection—the Flare Gas Recovery Unit (FGRU) must avoid drawing a vacuum that could induce air ingress through the flare tip. Industry practice is to maintain a small continuous purge flow to the flare to prevent oxygen entry. The control system is configured to ensure that the header pressure never falls below atmospheric.

To manage operation below the compressor's stable flow range, a recycle (spillback) loop is included. The centrifugal compressor is equipped with an anti-surge recycle line from discharge to suction, routed through a cooler, which opens automatically to maintain stable operation when flow decreases. The liquid-ring compressor can technically tolerate zero gas flow by circulating only its seal liquid; however, to prevent vacuum formation, it is provided with a recycle path and can operate in an unloaded state during low-flow conditions.

When the flare-gas rate drops below the compressor's minimum handling capacity, the control logic recirculates a portion of the gas from the booster discharge back to the suction drum to maintain a minimum flow through both machines. This approach allows the system to remain online and avoid frequent start–stop cycling, at the cost of some efficiency, since the same gas is recompressed in a loop. This mode is acceptable for short durations or transient conditions.

If the flare-gas rate remains close to zero for an extended period (for example, during field-wide gas rerouting), operators may opt to shut down the FGRU entirely and rely on the flare pilot purge to handle the small residual flow. The system is capable of turndown to very low gas rates; however, operational safety and air ingress prevention dictate that a small purge to the flare (on the order of a few hundred standard cubic feet per hour) should always be maintained. The design target is therefore greater than 99% capture efficiency, with a minimal continuous bleed to the flare serving as a safety safeguard.

4.6.3 Startup and Shutdown Sequences

When starting up the system, the compressors will be brought online first before the engines. A typical sequence: the centrifugal compressor is started with its recycle valve wide open (so it doesn't immediately pressurize the header). The liquid ring may be started and left circulating with discharge throttled until ready. As the centrifugal comes up to speed, the control valve from the header gradually opens to let gas in, while simultaneously throttling recycle. This way, the header pressure is gently drawn down to ~ 0.05 -- 0.07 barg without overshoot. Once the compressors are running stably and the fuel gas buffer vessel is up to pressure (~5 bar), the engine generators can be started one by one. There will be a fuel gas surge drum near the engines (essentially a buffer volume) to damp out any pulsations or short-term fluctuations from the compressors and to ensure the engines have a steady supply. The engines are then synchronized to the grid and ramped up to the desired load. On a normal shutdown, the engines would be turned off first (or separated from the grid), and the compressor system would either be idled on recycle or also shut down. As the compressors stop, the header pressure will naturally rise and any remaining gas will go out the flare. A fast stop or trip is more challenging: say the compressors trip due to power loss—in that case, they stop drawing gas, so header pressure will rise and the flare seal will open. The engines will suddenly see their fuel supply pressure drop (since no compression), and within seconds they will detect low fuel and trip offline as well (engines generally have a low fuel pressure shutoff to prevent running lean and damaging pistons). This results in an immediate flare of all gas and a power loss. To mitigate the operational impact, either the CPF should have an automatic transfer to an alternate power source (if available) or at least a UPS for critical control systems to ride through until power is restored. The design will include non-return valves and slam-shut valves as needed to prevent any reverse flows (for example, if engines trip, to prevent backflow of gas from the buffer vessel to the compressors or header). In general, because the flare takes over the gas disposal seamlessly, the main consequence of a sudden trip is the loss of power—which is a serious concern for operations, hence why redundancy and possibly maintaining a small backup generator is recommended. This is further discussed under reliability (Section 4.7).

4.6.4 Electrical Integration and Load Management

The engine generators will be tied into the CPF's electrical system via a local switchboard. A **Power Management System (PMS)** will govern their operation. The PMS will ensure that the engines follow the CPF load: for example, if at night the CPF only requires 6 MW, the PMS might shut down one engine and run the others at higher load (for better efficiency), or run all at 60%—this depends on the optimal configuration. Reciprocating engines maintain good efficiency even at part loads (down to ~50% load) compared to gas turbines which drop off steeply, so part-load operation is not problematic. The PMS will also coordinate startup/shutdown of engines to avoid blackouts. If an engine trips, the PMS will attempt to increase output on the others (within their capability) and might send an alarm or start a standby unit. If all engines trip (due to FGRU trip or other issue), the PMS should instantly disconnect them to avoid backfeeding and will either transfer the load to grid (if grid-connected) or signal an emergency generator to start. These control and protection schemes ensure that the CPF's power supply remains stable or, in the worst case, fails safe (i.e., it trips off rather than causing damage).

To summarize integration: The FGRU and flare operate in tandem such that the flare is always a pressure-relief path for the system. The control strategy maintains a slight header pressure to prevent air ingress, uses a recycle control to handle low flows, and defers to the flare automatically for high flows. The engines and compressors are coordinated through a control system to handle transients smoothly. In all scenarios, the design prioritizes safety (flaring whenever needed) and tries to maximize gas recovery when conditions allow. Figure 4.2 (conceptual) illustrates the control philosophy in various situations: normal operation (all gas to FGRU, flare pilot on), low flow (recycle opens, some purge to flare), high flow (excess gas lifts seal to flare), and trip (all gas to flare, engines shut down). The integration ensures that the flare system's integrity is never compromised—it remains the ultimate safety device.

(Safety note: Flashback prevention measures will be incorporated into the system design. The water seal acts as the primary flashback arrestor, since flame cannot propagate through the water barrier. The seal will be specified as a deep type (~760 mm), as commonly recommended for flare recovery systems. If, for any reason, the flare did not include a water seal, a flame arrestor would be installed on the FGRU suction line to stop any flame propagation. Flame arrestors, however, add pressure drop and require additional maintenance; therefore, reliance on the water seal and sufficient piping distance is preferred. The existing KO drum and associated piping length also provide adequate quenching distance for any potential flashback. During detailed design, a hazard analysis will confirm these safety provisions.)

4.7 Operational Considerations and Challenges

4.7.1 Ambient Temperature Effects

The wide ambient temperature range (10 °C to 50 °C) affects both equipment performance and process conditions. At high temperatures (~50 °C), the air density is lower, impacting the engines as discussed— anticipated up to ~10% reduction in engine power output on the hottest days. For example, if each engine is rated 3.3 MW at 30 °C, it might deliver only ~3.0 MW at 50 °C, have mitigated this by using multiple engines with some margin, so even with a slight delay the total can still approach 9–10 MW (perhaps by running an extra unit if available). The combustion air temperature also influences knock tendency: hotter intake air could increase knock likelihood, but modern engines have intercoolers to maintain charge-air around 40 °C, so this is less of an issue. The compressors, on the other hand, have to do more work at high ambient because the gas is less dense. As noted, the centrifugal compressor might draw ~4+ MW in summer vs ~3 MW in winter for the same mass flow. I have accounted for the worst-case (summer) in motor sizing. The cooling systems (for engines and intercoolers) also face a tougher job in summer; adequate cooling tower or air cooler capacity must be installed to reject heat at 50 °C ambient.

At low temperatures (~10 °C), engine performance improves slightly due to denser air intake; however, engines remain limited to their rated output, ensuring that design power is not exceeded. The main concern in cold weather is hydrocarbon condensation: when equipment cools, heavy C_6^+/C_{14}^+ fractions can condense into liquids within pipes and vessels. During startup from cold conditions, slugs of condensate may accumulate in the flare header or knockout drums. To mitigate this issue, procedures are in place to drain the KO drum of any liquid prior to startup, and pre-warming of the flare header or critical piping can be applied where feasible. Heat tracing or insulation may also be implemented on sections of piping prone to liquid accumulation, such as the fuel-gas line to the engines, to maintain temperatures above the gas dew point. Because the heavy ends in the gas can raise the hydrocarbon dew point significantly (possibly well above 0 °C), even mild cooling during the night could result in condensation in stagnant areas. Continuous draining and the maintenance of a small purge flow—such as circulating a minimal amount of gas to the flare as a sweep—help prevent condensate buildup. In summary, high ambient temperatures slightly reduce capacity (addressed by design margins), whereas low ambient temperatures introduce condensation risks (addressed through heat tracing, insulation, and operational procedures). These factors are manageable and typical of similar projects operating in climates such as Ahvaz. All components are designed for a 50 °C worst-case scenario, with winterization (insulation and tracing) applied for the 10 °C case. Consequently, the system is expected to perform year-round with only minor variations in power output, which the CPF can tolerate; indeed, CPF demand is likely to vary seasonally, being higher in summer due to cooling requirements, a condition already considered in the design.

4.7.2 Handling Variability in Gas Flow

Flare-gas flow rates are inherently variable. The nominal 36 MMSCFD represents an average peak; actual hourly rates may fluctuate, and flaring could decline over the field's life as production changes. Designing for the full 36 MMSCFD ensures capacity for the most demanding routine conditions, although the system will often operate at part load.

- **Multiple Compression Trains:** Using parallel compressors (both liquid-ring and centrifugal) provides inherent turndown capability. For example, if flaring decreases to 50 % (≈ 18 MMSCFD), one of two compressor trains can be idled while the other operates near full load, a more efficient configuration than running both at half capacity. Likewise, if only approximately 5 MW is required or if sufficient gas is available for that output, some engines can be shut down and the remaining units run at higher efficiency. The modular configuration enables stepwise adjustment to match prevailing flow. The system has been sized such that N–1 units can handle a substantial portion of the load, maintaining smooth operation during moderate fluctuations.
- **Automatic Recycle Control:** For short-term or moderate reductions in flow, frequent machine cycling is avoided to reduce wear and prevent power interruptions. Recycle loops on the compressors manage brief low-flow periods by recirculating gas internally. For instance, if flaring temporarily drops because a well is choked back for a short duration, the centrifugal compressor can recycle part of the gas to avoid surge, while the engines throttle down slightly. This avoids unnecessary shutdowns. A small efficiency penalty is accepted during these transient periods because internal recycling maintains operational continuity.
- **Minimum Flow and Purge Management:**A minimum flow to the flare is always maintained to keep the pilot flame lit. The control system prevents the header pressure from dropping below approximately 0 barg, thereby avoiding air ingress. Maintaining a small continuous purge flow to the flare, even at extremely low flaring conditions, is standard industry practice. This purge flow (typically only a few MSCFD) is negligible in terms of fuel loss but essential for safety. When production approaches zero, the FGRU either recycles the gas entirely or shuts down, allowing the small purge stream to flare. This strategy eliminates more than 99 % of routine emissions while ensuring safe operation without creating a vacuum in the header.
- **Response to Rising Gas Volume:** If gas flow gradually increases, for example as additional wells are brought online, the system can process up to its design limit of 36 MMSCFD. When flows exceed this threshold, the excess gas is automatically directed to the flare once the water seal pressure exceeds 0.07 bar. Continuous flaring of such excess indicates that system capacity has been reached, at which point expansion may be considered, such as by adding another compressor train or engine. The configuration is inherently future-proof: with parallel units, additional capacity can be added proportionally if plot space and utilities permit. Conversely, if long-term flare rates fall significantly below design (for instance, to 10 MMSCFD following gas-reinjection projects), equipment would operate under-loaded—an acceptable but less efficient condition implying over-investment in capacity. As noted in Section 4.8, economic optimization could downsize the system if lower flows are anticipated; however, the current design prioritizes maximum flare-gas elimination over potential underutilization.

- In summary, the system provides high flexibility in handling variable flare-gas flow through modular equipment, parallel operation, and automated control strategies. Most operating scenarios are managed automatically: the flare acts as a constant, safe relief path for excess gas, while the FGRU adjusts or idles as required. This arrangement ensures optimized efficiency and maintained safety by avoiding both air ingress and over-pressurization of the header.

4.7.3 Flare Bypass and Safety Provisions

A fundamental operational requirement is that the flare header must never become a closed or trapped system; a permanent route to the flare must always remain available in case the Flare Gas Recovery Unit (FGRU) is not operational. The design inherently ensures this function through the liquid seal while incorporating additional safety provisions.

4.7.3.1 Bypass Line and Valving

In some FGRU configurations, a dedicated bypass line equipped with an automatic valve is used to divert gas to the flare if compressors trip. In this case, the water seal already performs that role passively, requiring no active valve. Nevertheless, a manual or fail-open bypass valve is installed around the FGRU isolation line so that maintenance activities can route gas directly to the flare when needed. All critical FGRU valves—such as the suction block valve—are configured to fail safe: open to the flare and closed to process equipment upon loss of power or instrument air, ensuring any unforeseen event defaults to flaring.

4.7.3.2 Instrumentation and Response Time

The flare header's pressure transmitters are integrated into the FGRU control system, ensuring safety in operation. Should the header pressure exceed its normal range, indicating a failure in gas removal by the FGRU, an alarm is triggered. The system then automatically isolates and transitions to a safe state. In the event of an unexpected FGRU trip, such as a compressor or engine failure, the sudden pressure increase is immediately mitigated by the water seal. Non-return valves simultaneously prevent backflow from compressors or fuel-gas lines. This design inherently makes the system fail-safe: any power loss or emergency shutdown automatically directs gas to the flare for safe disposal.

4.7.3.3 Flashback Prevention

The water-seal drum functions as the primary safeguard against flashback from the flare tip. A seal depth of approximately 760 mm is maintained, a standard industry recommendation to prevent flame propagation. The distance between the flare tip and the FGRU tie-in, together with the knockout-drum volume, provides additional quenching distance. If a flare system lacking a water seal is encountered, a flame arrestor will be installed on the FGRU suction line. Because flame arrestors introduce pressure drop and require maintenance, reliance on the existing water-seal arrangement remains the preferred solution.

4.7.3.4 Emergency Shutdown (ESD) Integration

The FGRU and engine plant are integrated into the facility's ESD system. In an emergency (e.g., gas release, fire, or critical process deviation), the FGRU and engine will immediately shut down, and all gas will be diverted to the flare. During an ESD event, compressors isolate, the flare manages the blowdown, and engines stop. This rapid return to conventional flaring safely removes hydrocarbons from process systems. Once normal conditions are restored, the FGRU can be restarted.

4.7.3.5 Maintenance Bypass

When the FGRU requires maintenance, operation reverts to full flaring. Compressors and engines are stopped, isolation valves are closed, and the entire gas stream flows to the flare as before project implementation. Although this temporarily reinstates environmental and fuel-loss impacts, such maintenance is typically scheduled during low-production periods or planned CPF shutdowns to minimize effect. The design allows easy transition between recovery and full-flaring modes, ensuring operational flexibility. Annual maintenance may result in limited downtime—on the order of several days or weeks—yet this remains a major improvement compared with continuous flaring throughout the year.

Overall, the flare system remains a continuously available, fully open safety path. No operational condition can lead to gas entrapment or hazardous vacuum formation within the flare header. The design fully satisfies the fundamental requirement of maintaining safe and uninterrupted flaring capability while enabling recovery under normal conditions.

4.7.4 System Reliability and Maintainability

Because the project is directly connected to both the safety and power-generation functions of the CPF, reliability constitutes a critical design priority. The system incorporates several measures to ensure high availability and ease of maintenance.

4.7.4.1 Redundant Units (N+1 Philosophy)

Multiple compressors and engines are installed in parallel to eliminate single-point failures. For instance, three engines provide the 10 MW load so that, if one fails, the remaining two can still supply 6–7 MW for essential operations while non-critical loads are temporarily shed. Similarly, at least two 50 %-capacity compressor trains operate in each stage; if one train trips, the other continues to recover approximately half the gas, preventing complete shutdown. Equipment is specified so that, with one unit out of service, critical loads remain supported. Although this introduces modest additional cost, it significantly increases system uptime.

4.7.4.2 Proven Engine Technology

Medium-speed gas engines have a long record of reliability in oilfield applications, commonly achieving 90–95 % availability with proper maintenance. Regular overhauls—top-end at ≈ 8,000 hours and major at ≈ 30,000 hours—are scheduled to minimize disruption. Maintenance can be staggered to keep the plant operational at all times, and one engine may be maintained as a hot-standby unit ready to start if another trips. Reciprocating engines' robustness and adaptability make them particularly suited for remote installations.

4.7.4.3 Compressor Reliability

The liquid-ring compressor (LRC) is a low-speed, simple device with minimal wear components, whereas the centrifugal booster operates reliably if kept within its surge and vibration limits. Condition monitoring—vibration and temperature sensors—detects early signs of degradation. Parallel trains allow maintenance on one set while the other continues operating. Critical spares such as seals, bearings, or rotors are stored on site to minimize repair time.

4.7.4.4 Utilities and Power Dependency

Compressors depend on power supplied by the engines, and the engines rely on compressed gas—creating mutual dependency. During startup, auxiliary power from the grid or a diesel generator energizes the compressors until engine-generated power becomes available. In a total trip, compressors and engines stop simultaneously and all gas reverts to the flare, ensuring safety. To improve restart reliability, a small uninterruptible power supply or black-start generator can maintain essential auxiliaries such as seal-water pumps or one compressor, enabling an islanded restart sequence.

4.7.4.5 Scheduled Maintenance and Downtime

Periodic maintenance unavoidably results in limited downtime, during which flaring resumes temporarily. A realistic target availability for the FGRU is ≥ 90 %, corresponding to roughly 36 days of annual downtime. Backup power arrangements—temporary grid import or diesel generators—should be available during these intervals. Ideally, FGRU maintenance aligns with broader CPF maintenance periods when power demand is minimal.

4.7.4.6 Operational Staffing and Support

Operating a gas-engine power plant with associated compressors requires skilled personnel. Operator training, vendor support, and long-term maintenance agreements are therefore essential. Proper staffing and adherence to vendor service protocols are decisive factors in ensuring system reliability.

4.7.4.7 Environmental Reliability

Environmental performance is directly linked to operational uptime. Frequent FGRU outages would negate the intended emissions reduction. Achieving ≥ 90 % availability ensures that most of the flare gas is captured year-round, thereby maintaining both environmental and economic benefits.

In conclusion, the system integrates multiple layers of reliability: redundancy, proven technology, continuous monitoring, and structured maintenance. Sustained operational excellence is essential for realizing these benefits. Subsequent sections analyze assumptions and recommend additional measures to further enhance dependability.

4.8 Emissions Impact and Uptime

Capturing the flare gas substantially reduces overall emissions, provided that engine exhaust remains within acceptable limits. Flaring, although efficient in oxidizing hydrocarbons to CO_2, often exhibits methane slip and particulate emissions. Lean-burn reciprocating engines combust the gas more completely, nearly eliminating methane slip and thereby providing a significant greenhouse-gas reduction. The CO_2 emitted from engine combustion corresponds to that already produced during flaring; however, in this configuration, it yields useful power. When this power displaces diesel-generated or grid electricity, a net decrease in total CO_2 emissions is achieved.

Modern engines can comply with stringent NO_x and CO emission limits; if required, oxidation catalysts or SCR systems may be installed. Given the remote location, environmental regulation is likely focused on flaring reduction rather than engine exhaust, though compliance with any applicable standards should be verified.

The environmental and economic benefits are contingent upon maintaining high uptime. If the FGRU is frequently offline, flaring resumes and emission reductions decline proportionally. High availability (≥ 90 %) ensures near-continuous capture. Unlike many prior studies that discuss flare-gas utilization in generic terms, this work applies a complete mass- and energy-balance to a specific oilfield case. By refining the simplified 14.5 MW theoretical potential, introducing detailed parasitic-load estimates (~ 3 MW), and accounting for fuel-gas conditioning of heavy hydrocarbons, the study provides a realistic assessment of flare-gas recovery.

The proposal is based on optimistic yet reasonable assumptions regarding gas properties and equipment performance. Critical uncertainties—such as variable flaring rates, potential contaminants, or engine knock sensitivity—should be further examined through detailed simulations and vendor engagement. Dynamic process modeling, transient-response verification, and validation of compressor and engine compatibility under warranty conditions are recommended. If higher H_2S levels are confirmed, integration of an amine-treating unit should be considered. Anticipating such contingencies ensures the robustness of the engineering design.

4.9 Recommendations and Future Work

To strengthen the proposed configuration, several follow-up studies are recommended:

- **Partial-Flow Performance Analysis:** A comprehensive assessment of system performance at partial flaring rates (25 – 75 % of 36 MMSCFD) should be performed to confirm compressor surge margins, engine stability, and fuel-consumption trends. Results will verify that the configuration maintains efficiency during sustained low-flow operation.
- **Enhanced Compressor Turndown (VSD vs. Recycle):** Collaboration with the compressor manufacturer is advised to determine the optimal anti-surge control strategy. Employing variable-speed drives (VSDs) could reduce recycling losses during low-flow conditions. A life-cycle energy analysis should quantify power savings relative to capital cost, identifying whether VSD integration is economically justified.
- **Alternate Uses for Surplus Gas or Power:** If flare-gas availability exceeds 10 MW demand, options such as electricity export, gas reinjection, or modular gas-to-liquids (GTL) conversion could be evaluated. The electrical infrastructure may be pre-sized (e.g., 15 MW switchgear) to enable future expansion.
- **Maintenance and Spare Strategy:** A detailed Failure Mode and Effects Analysis (FMEA) should be conducted for each subsystem. Critical spares—such as compressor impellers or engine turbochargers—ought to be maintained on site. Vendor service agreements are recommended to guarantee timely support and spare-part availability.

Implementing these studies and vendor collaborations will enhance system reliability, energy efficiency, and long-term sustainability. The resulting configuration will be optimized for real-world operation while maintaining the environmental objectives of the project.

4.10 Summary and Comparison of Results

This chapter presented a comprehensive engineering proposal for flare-gas recovery and power generation at the Band-e-Karkheh field. The analysis distinguishes between gross and net outputs: the theoretical potential of approximately 14.5 MW translates to 10 MW gross and 7 MW net after accounting for parasitic loads.

The proposed system encompasses gas collection and pre-treatment (using the existing knockout drum and coalescer), two-stage compression (liquid-ring followed by centrifugal boosting to 5 bar), and electricity generation via reciprocating engines synchronized with the CPF grid. Integration with the existing flare ensures that routine gas is recovered while maintaining seamless transition to flaring during upsets. Operational strategies were developed to manage variable flow and ambient extremes, while limitations and future improvements were identified.

The design achieves approximately 10 MW gross electrical power, supplying the full CPF demand with recovered gas. After internal power consumption, about 7 MW remains available to the facility, representing ≈ 70 % of total demand. Continuous flaring of ≈ 36 MMSCFD is virtually eliminated under normal conditions, with only a small pilot or purge flame maintained. Occasional flaring occurs only during maintenance or emergencies. Consequently, methane emissions are minimized, and waste gas is transformed into a valuable energy source, improving both environmental and operational performance.

The environmental impact is significant: recovering ≈ 10 MW from ≈ 2 MMSCFD of gas prevents the release of approximately 40,000 $Sm^3\ day^{-1}$ of unburned methane, equivalent to about 23,000 t CO_2e per year (GWP_{100} = 28). Additional ≈ 18,000 t CO_2 per year are avoided by displacing grid or diesel generation. The combined reduction—≈ 41,000 t $CO_2e\ yr^{-1}$—corresponds to removing roughly 9,000 vehicles from service.

In conclusion, the proposed flare-gas recovery system represents a technically feasible, environmentally beneficial, and operationally reliable solution. It leverages proven technologies in an integrated configuration that converts an environmental liability into a clean-energy asset, aligning the Band-e-Karkheh project with global sustainability objectives such as the World Bank's *Zero Routine Flaring by 2030* and the UN Sustainable Development Goals 7 and 13.

To put the chosen solution in context, Table 4.2 compares the power generation outcomes of different scenarios analyzed (from Chapter 3 and this chapter):

Utilization Option	Electrical Output (MW)	% of CPF Demand (10 MW)
Total Flare Gas Potential (if 100% converted)	14.5 MW	145% (theoretical maximum)
Gas Turbine (simple cycle) (≈35% efficiency)	~5.1 MW	~51% of demand
Organic Rankine Cycle (ORC) (≈12% efficiency)	~1.7 MW	~17% of demand
Gas Turbine + ORC Hybrid	~6.8 MW	~68% of demand
Reciprocating Engines (gross) – this proposal	**10.0 MW**	**100% of demand**
Reciprocating Engines (net) – this proposal	**~7.0 MW**	**~70% of demand**

Table 4.2: Power Generation Options from 36 MMSCFD of Flare Gas

4.10.1 Environmental benefit

The recovery of ~10 MW from ~2 MMSCFD of flare gas avoids the continuous flaring of this volume, which would otherwise emit large amounts of methane and CO_2. Assuming a flare destruction efficiency of 98%, the project prevents the release of ~40,000 Sm^3/day of unburned methane. With a global warming potential (GWP_{100}) of 28, this equates to a saving of ~23,000 tonnes of CO_2e per year. In addition, displacing equivalent grid or diesel-based power reduces direct CO_2 emissions by a further ~18,000 tonnes/year, giving the system both local operational benefits and a measurable climate benefit.

In conclusion, the proposed flare gas recovery and power generation system is a technically viable and environmentally impactful solution for the Band-e-Karkheh field. It leverages proven technologies in a thoughtful configuration to turn a waste stream into a power source, aligning with both energy efficiency and emissions reduction goals. Final implementation will require detailed engineering, vendor collaboration, and operational planning (as outlined in recommendations), but the analysis in this chapter demonstrates that—under the assumed conditions—the system can deliver on its promise of ~10 MW of clean power and near-elimination of routine flaring. This represents a significant step toward sustainable field operations, reducing the carbon footprint and improving energy self-sufficiency for the asset.The project directly supports UN SDG 7 (Affordable & Clean Energy) and 13 (Climate Action).

Source of Savings	Assumption	Annual Reduction (tCO_2e/year)	Notes
Avoided methane slip from flare	2 MMSCFD used for engines; flare efficiency 98%	~23,000	Prevented release of unburned CH_4 (GWP_{100} = 28)
Displacement of alternative power (grid/diesel)	10 MW × 8000 h/year; 0.45 tCO_2/MWh	~18,000	Avoided fossil-based electricity generation
Total Climate Benefit	–	~41,000 tCO_2e/year	Equivalent to removing ~9,000 cars from service

Emissions Savings from Flare Gas Recovery

Chapter 5: Results & Conclusions

5.1 Technical Feasibility and Performance

The proposed Flare Gas Recovery Unit (FGRU) with reciprocating gas-engine generators has demonstrated technical feasibility in meeting the Central Processing Facility's (CPF) power needs. The system can recover and utilize the routine flare gas (up to ~36 MMSCFD) to generate approximately 10 MW of gross electrical power on-site. After accounting for parasitic loads (about 3 MW consumption), the net power delivered to the facility is on the order of ~7 MW. This net output covers about 70 % of the CPF's demand and represents energy that would otherwise be wasted. The concept of using rich associated gas to fuel reciprocating engines has proven technically viable and significantly improves on-site energy self-sufficiency.

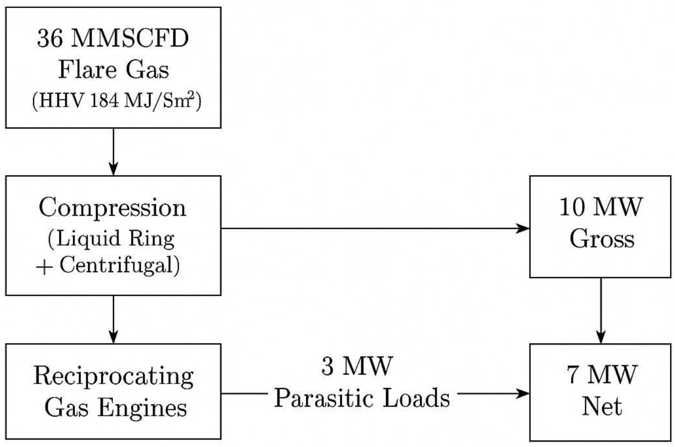


Figure 5.1 – System Energy Flow Diagram

Utilization Option	Electrical Outpu (MW)	% of CPF Demand (≈ MW)
Full Theoretical Conversion (100 %)	14.5 MW (max)	145 %
Gas Turbine (simple cycle, ≈35 % eff.)	~5.1 MW	~51 %
Organic Rankine Cycle (ORC, ≈12 % eff.)	~1.7 MW	~17 %
Gas Turbine + ORC Hybrid	~6.8 MW	~68 %
Reciprocating Engines (Gross, proposed)	10.0 MW	100 %
Reciprocating Engines (Net, proposed)	~7.0 MW	~70 %

Table 5.1 – Power Generation Outcomes from Flare Gas (36 MMSCFD): Comparison of Utilization Options and Outpu

5.2 Reliability and Operational Considerations

Reliability and operability are critical to success. The design incorporates features to ensure high uptime and safe operation. A redundant 'N + 1' philosophy is adopted for major equipment: multiple compressors and engine-generator units operate in parallel so that no single failure shuts down the system. Having spare capacity allows maintenance or outages in one unit to be compensated by others. This modular design improves reliability and provides flexibility to match generation to flare-gas flow. With proper maintenance, availability levels of 90–95 % are achievable.

5.3 Environmental Benefits and Sustainability

Recovering flare gas yields major environmental gains. In normal operation, the FGRU system would virtually eliminate routine flaring, replacing open burning with controlled, high-efficiency combustion inside engine cylinders. Approximately 36 MMSCFD of rich gas that was previously flared would be recovered, avoiding CO_2, unburned hydrocarbons, and soot while reducing heat and noise. The engines' lean combustion minimizes methane slip, transforming a pollution source into productive fuel and aligning with climate-mitigation objectives.

Source of Benefit	Basis of Calculation	Annual Reduction (t CO_2e yr^{-1})	Explanation / Notes
Avoided Methane Slip from Flaring	~2 MMSCFD gas used in engines (98 % flare efficiency)	~23 000	Methane converted to CO_2 in engines instead of escaping unburned.
Displacement of Fossil Power	10 MW × 8000 h yr^{-1} × 0.45 t CO_2 MWh^{-1}	~18 000	CO_2 avoided by replacing diesel or grid electricity.
Total GHG Reduction	–	~41 000	Equivalent to removing ≈9 000 cars from the road.

Table 5.2 – Emissions and Energy Benefits from Flare Gas Recovery.

5.4 Concluding Remarks

The implementation of a flare-gas-recovery and power-generation system at Band-e-Karkheh is technically feasible, environmentally beneficial, and operationally reliable. The project achieves its main goal: converting waste flare gas into a stable, clean power supply for the CPF. By combining proven technologies—two-stage gas compression and reciprocating gas engines—in a configuration adapted to local conditions, the system delivers approximately 10 MW gross (≈ 7 MW net) while nearly eliminating routine flaring. Safety is preserved through automatic flare-bypass control, and redundancy ensures high availability even under harsh ambient conditions.

In summary, the project bridges theory and practice by demonstrating that even high-BTU, variable flare gas can be harnessed efficiently for power generation. The quantified performance, reliability measures, and emissions savings show that flare-gas recovery can transform an environmental liability into a sustainable energy asset. With careful implementation, the Band-e-Karkheh FGRU project can become a model for similar fields, advancing both energy efficiency and environmental responsibility in upstream operations. The project aligns with the World Bank's "Zero Routine Flaring by 2030" initiative, positioning Band-e-Karkheh as a regional benchmark for sustainable oil-field power recovery.