

Innovative Solutions for Flared Gas: Enhancing Revenue and Reducing Emissions

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In 2023, the annual reported volume of natural gas vented or flared in the United States was approximately 0.5% of gross withdrawals, based on preliminary state and federal data¹. Flaring represents not only an environmental concern but also a significant economic loss for operators. Despite industry efforts to eliminate flaring, limited infrastructure and regulatory constraints leave operators with few viable alternatives.

Several technological solutions² exist to repurpose flared gas into useful products, including small-scale LNG or CNG production, pyrolysis for hydrogen and carbon extraction, and power generation for applications such as bitcoin mining. However, these solutions are often less practical than pipeline sales due to challenges such as decentralized gas sources, high capital expenditure requirements, and stringent permitting regulations. Another approach involves utilizing unprocessed gas for internal operations, thereby reducing energy costs and increasing revenue. However, this method presents operational challenges, including frequent engine maintenance due to the presence of heavy hydrocarbons in untreated gas besides not to state that there is only limited consumption of what is being flared.

Midstream processing plants often handle low-pressure, low-volume associated gas, which is typically rich in C₃-C₅ hydrocarbons and contaminated with water, CO₂, and in some cases H₂S. This paper explores a redesigned refrigeration module to recover and process off-spec gas for pipeline sales, increasing sales gas revenue and reducing emissions. The proposed system integrates mechanical refrigeration and glycol dehydration for gas treatment, a single-tower NGL stabilizer to recover valuable hydrocarbons, and membrane separation to remove CO₂.

A key sustainability benefit of this approach is utilizing membrane reject gas as fuel, which minimizes reliance on sales gas thereby increases revenue, and lowers CO₂ flaring. A defining feature of this system is its flexibility in processing capabilities while efficiently pairing with an appropriate generator, based on the reject fuel gas quality. This enables seamless integration with a combustion generator, ensuring the system remains fully self-sufficient and sustainable.

Additionally, this paper discusses optional processing modules that can be adapted to specific field conditions, along with the challenges and economic feasibility of implementing such technologies. By optimizing gas utilization, this approach presents a viable pathway to enhancing revenue generation while mitigating environmental impact in midstream operations.

1. Introduction

In 2022, approximately 185,000 MMSCF of natural gas was flared in the United States³. These volumes represent routine flaring rather than operational upsets or intermittent emergency events, and were contributed by nearly 500 facilities nationwide. To place this into perspective, if fully

recovered and utilized for power generation at 40% thermal efficiency and assuming a heating value of 950 BTU/SCF, this gas could generate approximately 2,340 MWe of electricity. Beyond power generation, the value of this gas extends further: liquid hydrocarbons could be recovered and monetized, volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) could be safely and efficiently disposed, and the remaining residue gas could be absorbed into existing markets.

Internationally, the scale of flaring is similarly significant. In the Middle East, routine flaring volumes are estimated at Saudi Arabia accounting for nearly 70 K MMSCF, the United Arab Emirates about 25 K MMSCF, and Egypt around 65 K MMSCF. These figures highlight the magnitude of recoverable energy resources being lost to routine flaring worldwide.

2. Flare Gas Characteristics and Site Conditions

Venting refers to the direct release of natural gas into the atmosphere during oil and gas production and associated operations. Because natural gas is primarily methane, venting contributes significantly to greenhouse gas (GHG) emissions⁴. Flaring, by contrast, involves the combustion of natural gas, which converts methane into carbon dioxide but still results in the release of unburned methane, volatile organic compounds (VOCs), and hazardous air pollutants (HAPs). Both practices represent a loss of valuable hydrocarbons and a source of environmental impact.

Flaring and venting⁵ may occur for a variety of operational reasons. In cases of equipment failure, safety testing, maintenance, or other unplanned events, operators engage in emergency flaring. These events are sporadic, short-lived, and permitted within regulatory limits established by state or federal agencies. For example, in the United States, operators may flare up to an average of 50 thousand cubic feet (MCF) per day during a given calendar month without prior approval from the Regional Supervisor. Because such occurrences are unpredictable and irregular, they are generally unsuitable for recovery projects; the highly variable and intermittent volumes make the design of a reliable capture system impractical.

In contrast, routine flaring represents a more consistent and predictable source of emissions. This occurs when operators lack sufficient pipeline takeaway capacity, when local treatment facilities are unable to bring gas to pipeline specifications, or when off-specification gas streams must be disposed off. In such cases, operators may resort to continuous flaring, sometimes for extended periods, despite the economic and environmental consequences. These routine streams constitute the primary target for recovery and monetization. By capturing these gases, operators can not only generate additional revenue but also reduce emissions, avoid penalties, and enhance overall sustainability.

Failure to address routine flaring can be costly. In several documented cases, operators have paid millions of dollars in fines and settlement costs to regulatory agencies as a result of non-compliance, underscoring the importance of proactive solutions.

3. Product Recovery and Utilization Pathways

Depending on gas quality, particularly the C₃+ content, and the availability of supporting infrastructure, flare gas can be recovered in several product configurations, including lean gas, Y-grade NGLs, or stabilized condensate. Lean gas streams, once treated, can be injected into existing sales gas pipelines. In locations without pipeline access, lean gas can instead be utilized for onsite power generation, providing electricity to operate the host facility, supply local grids, or serve growing high-demand consumers such as data centers, AI training facilities, and cryptocurrency mining operations. From an economic standpoint, lean gas carries a value of approximately \$3 per MMBTU based on Henry Hub pricing (Figure-1), while electricity generated from recovered gas is typically sold at an average of \$0.13 per kWh at the time this paper is written. These monetization routes illustrate the flexibility of modular recovery systems in transforming what would otherwise be flared gas into valuable products and services.

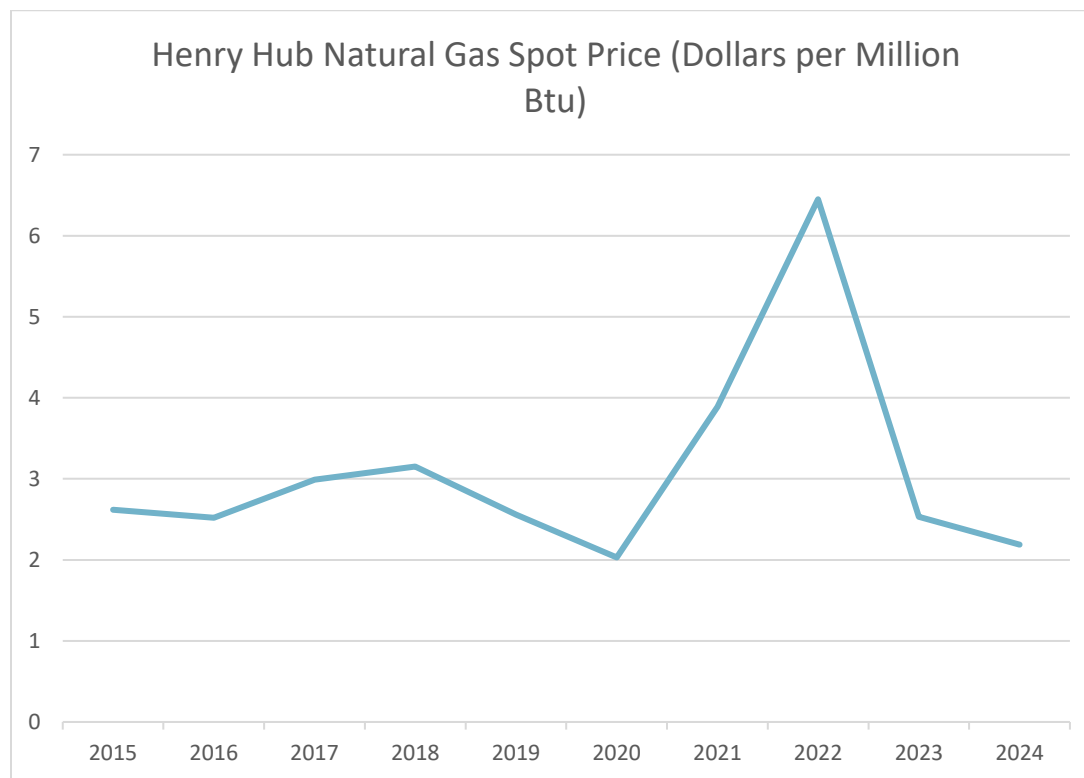


Figure 1: Henry Hub Natural Gas Spot Price⁶

Y-Grade price is around \$20-\$30 per barrel or \$6.6 / MMBTU (Figure -2).

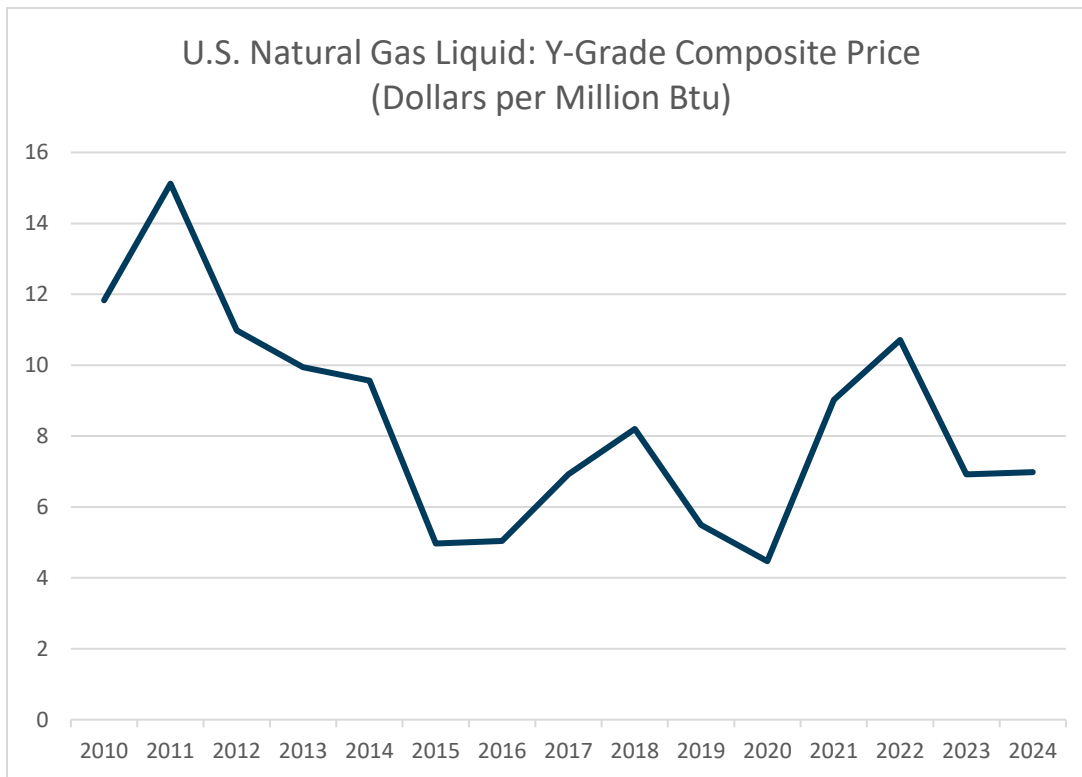


Figure 2: U.S. Natural Gas Liquids: Y-Grade Composite Price⁷

Stabilized Condensate trades at \$55-\$66/ barrel in 2025 (Figure-3).

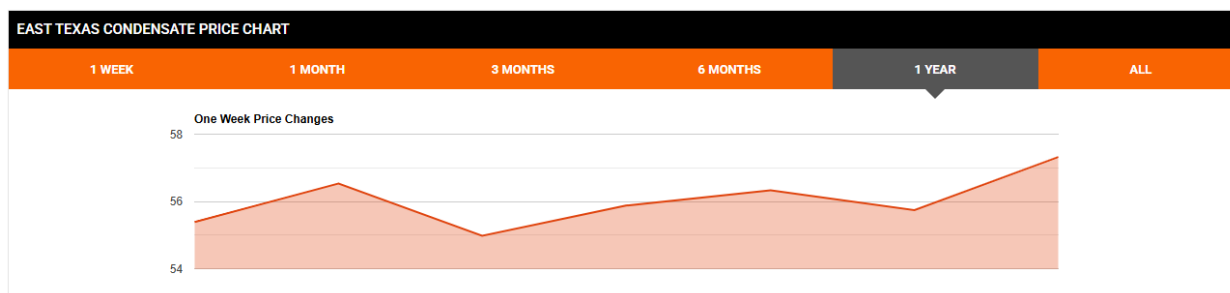


Figure 3: East Texas Condensate Price Chart⁸

4. Addressing Routine Flaring Through Flexible Recovery Systems

Significant volumes of natural gas, often in the range of 5 MMSCFD – 15 MMSCFD per site, are routinely flared across various locations in the United States. This practice results in multiple adverse outcomes, including loss of revenue, exposure to regulatory penalties and, in some cases, criminal charges or lawsuits, as well as considerable environmental impacts.

Conventional mitigation approaches such as small-scale LNG or CNG facilities have been explored; however, these are typically capital-intensive projects that depend heavily on long-term customer commitments. LNG developments involve long delivery schedules, specialized storage infrastructure, and complex metallurgy requirements for cryogenic service. Similarly, CNG systems must be designed for high-pressure operation and involve additional challenges in transportation and handling. As a result, both pathways are constrained by economic and logistical barriers that limit widespread deployment.

This paper presents an alternative solution that is simpler, more cost-effective, and yields higher-value products. The proposed system is a modularized package integrating mechanical refrigeration and glycol dehydration to bring gas to pipeline specification. A single-tower stabilization unit is incorporated to recover valuable condensates and sales gas components, while membrane separation is applied to remove impurities such as CO₂. More importantly, the membrane reject stream is not wasted but is utilized as a fuel source for power generation, reducing dependence on sales gas as fuel and preventing further CO₂ flaring.

The system can be tailored to individual fields, with optional processing modules added as required by site-specific conditions. The following sections of this paper will further examine the design, application, and operational challenges associated with this modular recovery approach.

5. Technical Design and Configuration

The modular flare gas recovery system consists of four primary modules and one optional module. The primary modules include:

1. Gas Treating / Conditioning System
2. Recycle Compressor Module
3. Membrane Skid
4. Power Generation System

The optional module is an Inlet Booster Compressor, which is required in site-specific cases where the source gas is low-pressure gas from LP separators or storage tank vapors.

5.1 Gas Treating / Conditioning System

The Gas Treating / Conditioning System is a single-module package comprising:

- Hydrocarbon Dew Point Control
- Mechanical Refrigeration Unit with Screw Compressors, associated lube oil system, and off-skid refrigerant condenser
- Monoethylene Glycol (MEG) Regeneration System
- Deethanizer / Stabilizer System with Reboiler

The system is designed based on the following parameters:

- C₃+ content in the gas stream (typical 10% – 20%)
- Desired C₃+ product recovery (high versus moderate)
- Treated gas objective (Sales Gas LHV versus Power Generation LHV)
- Liquid infrastructure and marketability (Y-Grade versus Stabilized Condensate)

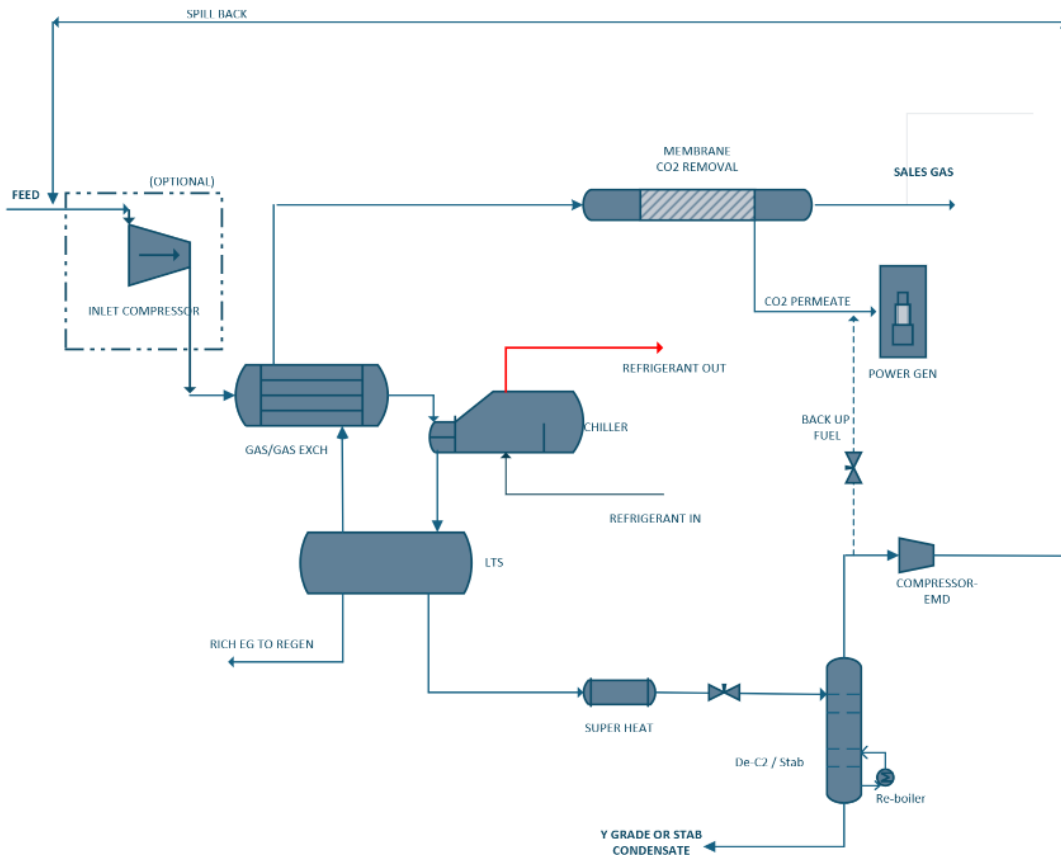


Figure 4: Gas Treating / Conditioning System

Hydrocarbon Dew Point Control

Gas is routed to the Dew Point Unit to regulate the calorific value and water content of the treated gas. The unit consists of a gas/gas heat exchanger, a gas chiller cooled by liquid propane from the mechanical refrigeration unit, and a cold separator with a boot. In the heat exchanger, the incoming gas stream is pre-cooled by exchanging heat with cold gas from the cold separator before being sent as export sales gas. The gas is further cooled in the chiller to the target temperature, which is determined by the desired C₃+ recovery and the sales gas calorific value (LHV). While C₃+ recovery and LHV are interdependent, one parameter typically takes precedence. MEG is injected at the inlet of both the gas/gas exchanger and the chiller to prevent hydrate formation.

The chilled process gas then enters the cold separator for three-phase separation. The separated gas exits as sales gas via the gas/gas exchanger, while condensate from the separator is routed to a superheater before flashing and transferred to the Deethanizer or Stabilizer tower. Water and MEG from the separator flow to the MEG regeneration package for glycol recovery.

Mechanical Refrigeration Unit

Mechanical refrigeration employs liquid propane as the refrigerant, cooling the process stream through the gas chiller. Liquid propane at its bubble point is stored in a refrigerant accumulator and routed to the gas chiller via a level control valve. Upon expansion through the valve, the propane forms a vapor/liquid mixture at a lower temperature. The liquid portion absorbs heat from the process through evaporation, providing the refrigeration effect, while the vapor does not contribute to cooling. The flashed propane vapor is then routed to the first stage of the refrigeration compressor via a suction scrubber, compressed, condensed, and returned to the refrigerant accumulator, completing the refrigeration cycle.

MEG Regeneration System

The rich glycol collected in the cold separator boot is routed to the reflux condenser located at the top of the glycol still. Within the condenser coil, the rich glycol is preheated while providing the cooling necessary to generate reflux and minimize glycol losses in the still. The glycol is then further heated via a heat exchanger with the hot lean glycol in the glycol/glycol exchanger before being directed to the flash tank. From the flash tank, the glycol exits under level control and passes through downstream filters. The filtered rich glycol enters the glycol reboiler/still, where it is distilled to remove the water absorbed during gas cooling in the gas/gas exchanger and chiller.

The glycol reboiler, an electric heater positioned beneath the glycol still, produces hot lean glycol that exits from the bottom of the reboiler surge section. Optionally, this lean glycol can serve as a heating medium for the Deethanizer or Stabilizer reboiler before returning to the glycol/glycol exchanger. This arrangement enhances sustainability by reducing reliance on external heating sources such as hot oil. The glycol injection pumps (one operating and one spare) circulate the lean glycol to the injection nozzles on the gas/gas exchanger and chiller. The inlet gas then carries the glycol back to the cold separator, completing the continuous glycol circulation loop.

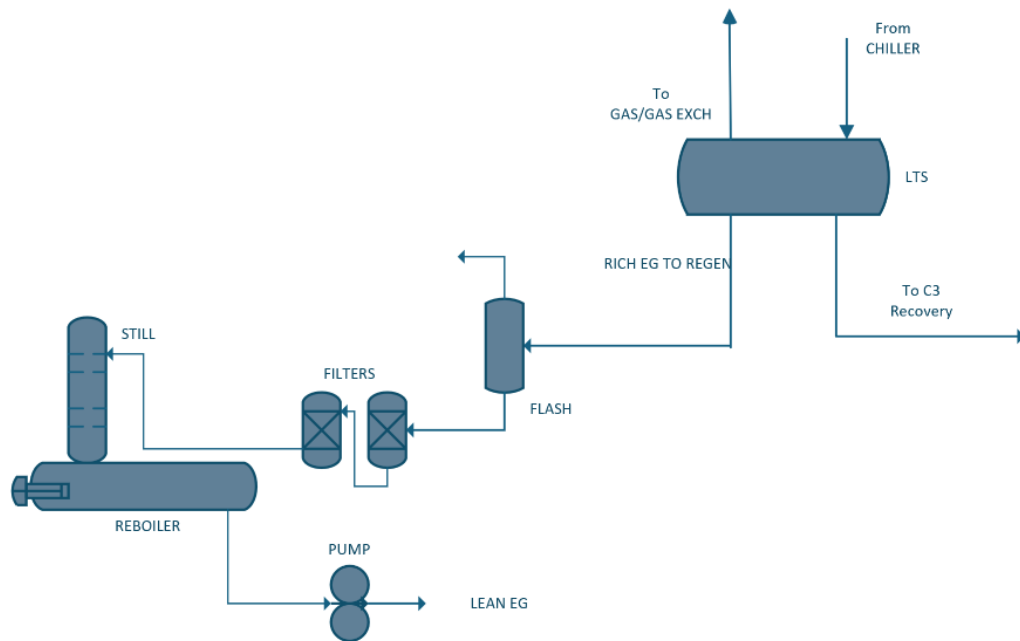


Figure 5: Dehydration System

Deethanizer / Stabilizer System

Cold NGL liquid from the low-temperature separator is superheated just enough to prevent hydrate formation during the pressure drop to the Deethanizer or Stabilizer tower. Hot propane from the refrigerant accumulator provides heat, allowing the superheater to serve both as an economizer on the refrigerant side and as a heater for the NGL.

The choice of tower type—Deethanizer or Stabilizer—depends on several factors. A Deethanizer produces a Y-Grade NGL as the bottom product, which requires pipeline infrastructure for marketing. In this configuration, C₃+ recovery is significantly high, making it a valuable commodity. Liquid product recovery is typically high, while the overhead product is primarily Methane and Ethane, producing lean gas suitable for fuel generation or blending with sales gas without compromising specifications.

In contrast, a Stabilizer tower produces a bottom product that meets the 9 psia RVP specification, creating a very stable liquid. This configuration does not necessarily require a pipeline, making it suitable for remote facilities with atmospheric storage tanks or virtual pipeline systems. The stabilized condensate is rich in C₅+, while C₃ and C₄ components remain in the overhead gas, resulting in a high-calorific fuel gas with 1,800 Btu/scf – 2,400 Btu/scf. Although this gas can be used for power generation, careful engine selection is required. In summary, the stabilizer configuration yields lower liquid product, minimal C₃/C₄ recovery, simpler infrastructure requirements, and necessitates careful consideration for engine applications.

5.2 Recycle Compressor Module: Configurations of Recycle Gas Compression

The Recycle compressor is employed to utilize the overhead gas from the Stabilizer or Deethanizer tower. Depending on process requirements, the compressor can be configured in one of two arrangements: Spill Back or End Spike.

Spill Back Configuration:

In the Spill Back configuration, the C_3+ rich overhead gas from the tower is compressed back to the inlet pressure of the Dew Point system. This arrangement enhances the equilibrium of C_3 components, improving C_3+ recovery in the NGL and increasing liquid product yields. Typical C_3+ recovery improvements range from 5% – 10%.

However, careful evaluation is required. If the feed gas contains more than 15 mol% – 17 mol% C_3+ , accumulation within the closed loop can disrupt equilibrium, making the arrangement economically unfeasible. Occasionally purging of the tower overhead to fuel gas or flaring can mitigate this, but such actions reduce process efficiency and may conflict with the goals of flaring reduction. In stabilized condensate systems, which produce a 9 psia RVP product, C_3 and C_4 components tend to circulate without being absorbed in the bottom product, requiring additional scrutiny. Spill Back is most effective under the following conditions:

- Feed gas C_3+ content within 15 mol% – 17 mol%.
- Y-Grade NGL production with high C_3 recovery.

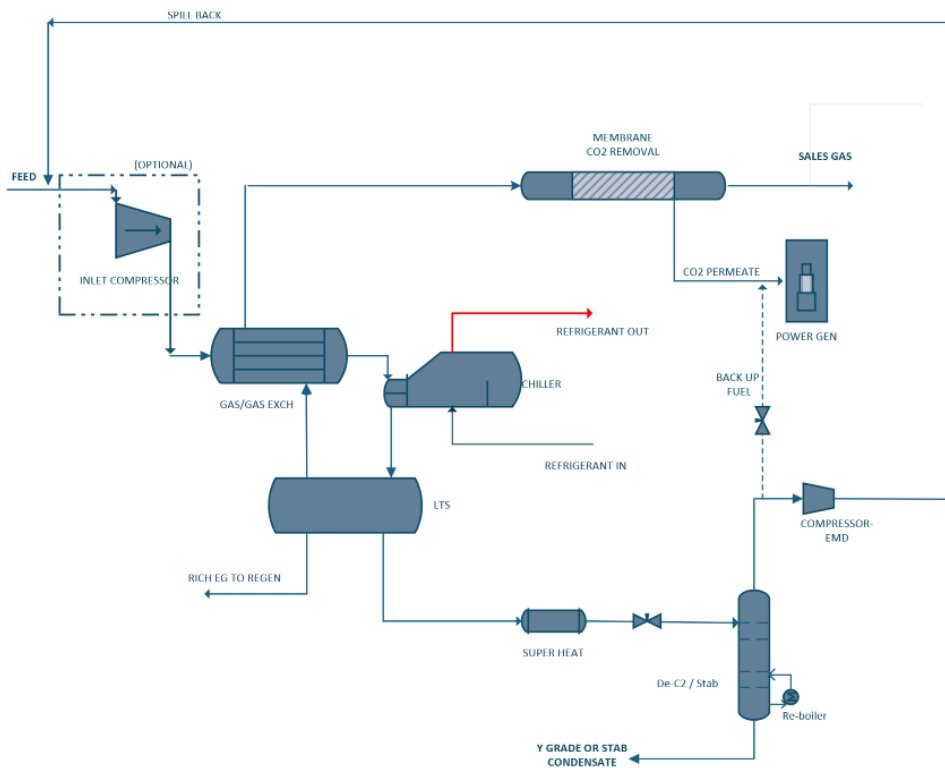


Figure 6: Recycle Compressor Module – Spill Back Configuration

End Spike Configuration:

The End Spike configuration uses the same compressor on the tower overhead, but instead of recycling to the Dew Point system, the discharge blends with the sales gas. This approach is advantageous when the sales gas LHV is not constrained and can be used primarily for power generation. End Spike is particularly suitable for applications such as AI training centers, crypto mining facilities, or plant power generation.

While the End Spike arrangement generally produces higher sales gas LHV and can meet pipeline specifications depending on feed gas composition and tower design, it results in lower liquid product recovery compared to Spill Back. The primary tradeoff in End Spike operation is between maximizing recovery and maintaining product stability (RVP) or pipeline specifications for both gas and liquid streams.

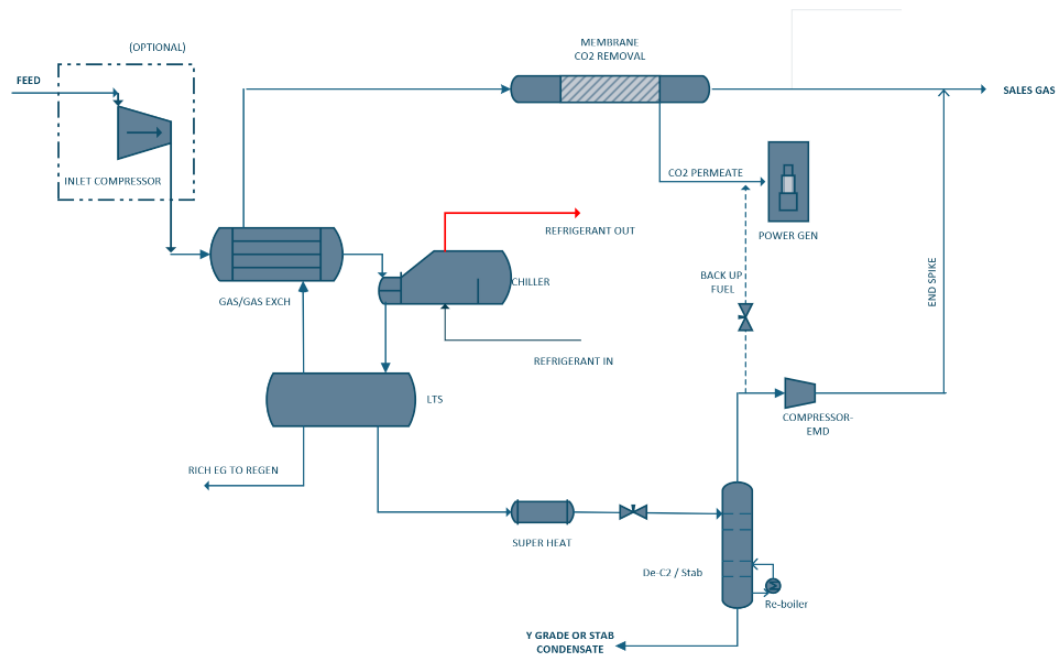


Figure 7: Recycle Compressor Module – End Spike Configuration

5.3 Membrane Skid

The dew-pointed gas, often rich in CO₂, typically requires treatment to reduce CO₂ content to below 2 mol% before being sent to the sales gas pipeline. For applications where modularity, cost, and construction time are important, a membrane system provides an effective solution for bulk CO₂ removal. This module can be optional, depending on the end use of the treated gas. For pipeline-quality sales gas, the membrane system is highly advantageous, while for remote power generation applications—such as off-grid electricity supply—its use may be avoided, as modern gas engines can tolerate higher CO₂ levels.

Positioning of the membrane skid is critical. It is recommended at the tail end of the gas treatment system, downstream of the Dew Point unit. This placement ensures that the gas is free of particles, water, and liquid hydrocarbons, which can negatively affect membrane performance. Another benefit is that variations in feed flow or CO₂ composition do not disrupt the overall system performance, unlike chemical absorption processes such as amines. Multiple membrane compartments can be configured to allow online replacement without downtime.

Membrane CO₂ removal is typically staged in two or three sections. Even though the membrane selectively removes CO₂, the permeate stream carries some hydrocarbons, necessitating staged removal and, in some cases, a recycling compressor. The innovative and sustainable aspect of this design is the use of the CO₂-rich membrane reject stream as fuel for on-site power generation. By carefully selecting generators capable of burning this CO₂-rich gas, the system becomes largely self-sufficient, generating sufficient energy to operate the treatment units while safely releasing CO₂ to the atmosphere without additional VOCs or HAPs. If the lower heating value (LHV) of the membrane permeate is insufficient for power generation, the tower overhead gas can be blended to achieve the required energy content.

This approach not only increases system independence from site utilities but also contributes to carbon capture and energy efficiency, enhancing overall sustainability.

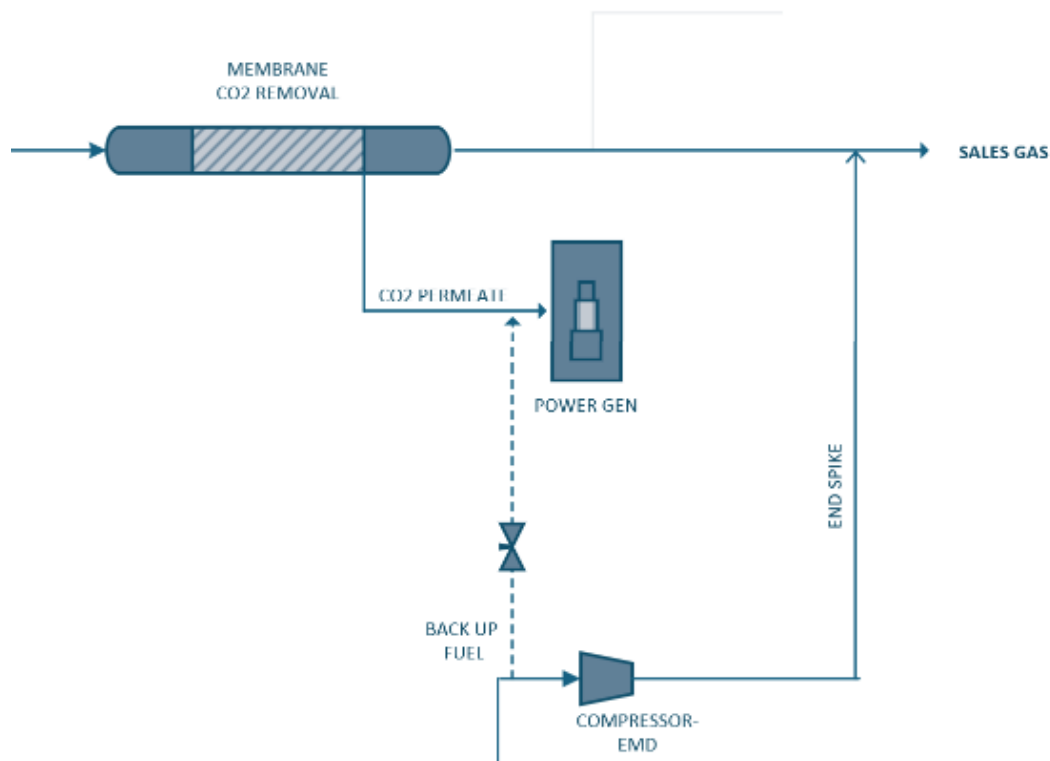


Figure 8: Membrane Reject and Tower Overhead Fuel Connection

5.4 Power Generation Module

The power generation module is designed to meet site-specific energy requirements. It can be configured to supply power solely to the gas treatment modules, to the entire facility, or to high-demand applications such as data centers. These units are standalone systems that utilize either treated sales gas or the CO₂-rich reject gas from the membrane skid.

Depending on the gas composition and system configuration, the modules typically require less than 700 horsepower to handle capacities of up to 15 MMSCFD. For most installations, a single power generation unit is sufficient to meet these energy demands, ensuring efficient and reliable operation of the overall gas recovery system.

5.5 Inlet Booster Compressor (Optional)

The inlet booster compressor is an optional module, added when the source gas is from low- or ultra-low-pressure units, making it a site-specific requirement. The flare gas recovery system performs optimally at pressures above 300 psig, with a preferred operating range above 500 psig.

Operational pressures are primarily influenced by two factors:

- Low Temperature Separator (LTS) temperature / dew point
- Membrane system requirements

Higher inlet pressures allow the system to achieve lower dew point temperatures, facilitating the attainment of the target calorific value at a reduced cooling duty. Additionally, elevated inlet pressure increases the differential between the feed and permeate streams in the membrane system—referred to as the feed-permeate pressure ratio—an important parameter for maximizing membrane separation efficiency.

5.6 Summary of Technical Configuration

The modular flare gas recovery system integrates four primary modules—Gas Treating/Conditioning, Recycle Compressor, Membrane Skid, and Power Generation—with an optional Inlet Booster Compressor for low-pressure sources. The design offers flexibility to adapt to varying gas compositions, infrastructure, and end-use requirements. To put the footprint in perspective, the main Gas Treating/Conditioning module is the largest at approximately 45'(L) × 15'(W) × 15'(H), yet the modular configuration allows for easy transport, installation, and integration into diverse field layouts. Overall, the system provides an efficient, adaptable, and sustainable solution for recovering flare gas and associated liquids.

6. Case Studies

6.1 Dataset Selection and Analysis

Representative datasets from both the U.S. and selected international sites were analyzed to capture a wide spectrum of flare gas scenarios and operating conditions. The primary objective is to evaluate the process configurations and identify the parameters guiding key design decisions, such as:

- End Spike versus Spill Back compressor arrangements
- Y-Grade versus Stabilized NGL production

The datasets include California, Utah, West Texas, Indonesia, and Oman, covering a range of flow rates, pressures, temperatures, and gas compositions.

Parameters	California	Utah	Indonesia	Oman	West Texas
Temperature [°F]	90.00	52.92	120.00	140.00	69.81
Pressure [psig]	700.00	309.07	1150.00	395.00	205.00
Molar Flow [MMSCFD]	4.50	25.16	50.09	12.23	2.60
Methane	75.01%	14.906%	79.96%	51.22%	45.31%
Ethane	5.65%	5.567%	4.19%	11.50%	24.10%
Propane	8.57%	4.649%	2.75%	8.99%	12.83%
i-Butane	1.40%	0.865%	0.47%	0.88%	1.61%
n-Butane	3.58%	4.116%	0.66%	3.13%	3.48%
i-Pentane	0.89%	0.870%	0.24%	0.61000%	0.58%
n-Pentane	0.73%	1.514%	0.19%	1.25%	0.58%
n-Hexane / C ₆₊ (*)	0.79%	0.540%	0.20%	2.40%	0.21%
n-Heptane	--	0.205%	0.15%	--	0.05%
n-Octane	--	0.032%	0.06%	--	0.01%
n-Nonane	--	0.002%	0.01%	--	0.00%
n-Decane	--	0.002%	--	--	0.00%
H ₂ O	--	0.018%	--	0.37%	0.06%
Nitrogen	1.00%	1.389%	1.18%	3.970%	0.13%
CO ₂	2.38%	65.212%	9.93%	15.680%	11.03%
H ₂ S	--	0.116%	--	--	--

Table 1: Flare Gas Scenarios and Operating Conditions for U.S. and Select International Sites

* Where the composition set stops at n-Hexane / C₆₊, the components are assumed as C₆₊ lumped together.

Assumptions and Methodology

- Inlet water is assumed saturated unless otherwise specified.
- Payback is evaluated on the basis of 5 MMSCFD and 15 MMSCFD train multiples.
- Simulations use the Peng-Robinson EOS in Aspen HYSYS V14.

Each dataset is tested under four process configurations:

- Spill Back with 9 psia NGL
- Spill Back with Y-Grade
- End Spike with 9 psia NGL
- End Spike with Y-Grade

Evaluation criteria include:

- Sales gas calorific value (LHV)
- Refrigerant and booster compressor horsepower
- NGL recovery (Y-Grade / Stabilized)
- C₃+ recovery at constant TVP (100 psig)
- Exchanger duties

Location	Flow (MMSCFD)	C ₃ + %	Highlights
California	4.5	16%	Moderate flow; High pressure
Utah	25.2	13%	Very High CO ₂ ; Mid pressure
Indonesia	50.1*	4.70%	Very High flow; Very low C ₃ +
Oman	12.2	17.3%	High flow; Mid pressure
West Texas	2.6	19.4%	Low flow; Low pressure; High C ₃ +

Table 2: Case Study Characteristics

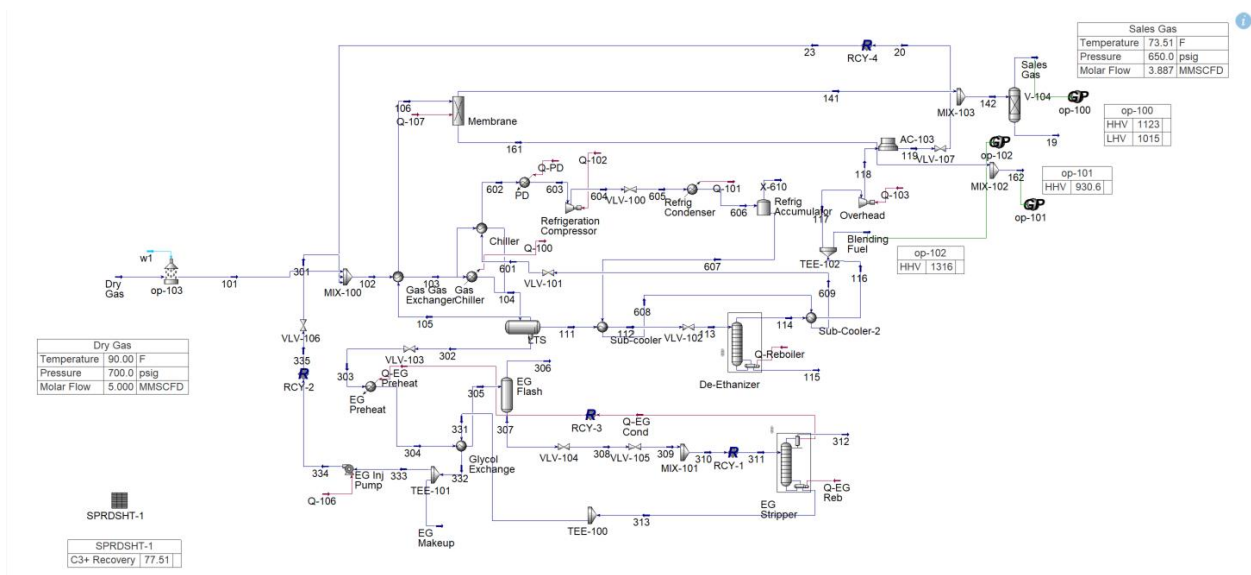


Figure 9: Process Simulation Snapshot

6.2 Economic Analysis and Payback

The economic analysis provides insight into the expected payback period of flare gas recovery systems compared to continued flaring. While flaring represents lost revenue and often triggers regulatory penalties, recovery projects generate revenue from sales gas, NGL, and condensate.

Key Assumptions:

- Gas Revenue: \$3/MMBtu*
- NGL Revenue: \$6.5/MMBtu*
- Condensate Revenue: \$55/bbl*

*Assumed price from US Energy Information Administration

- BTU conversion: Propane assumed at 91,300 BTU/gal
- Payback period calculation assumes plant installation and construction period of 12-months and OPEX is compensated out of the Revenue
- Cost estimates are indicative, subject to variation based on geography, steel prices, and market conditions. The cost estimation table below is a representation of reliable high-level values approximated to the nearest multiples of 500 /1000s for market understanding.

Cost Description	5 MMSCFD	15 MMSCFD
EG, HCDP, Stab, Refrig	\$3,000,000	\$ 4,000,000
Booster	\$ 930,000	\$ 1,150,000
Membrane	\$ 1,100,000	\$1,430,000
Power Gen	\$ 750,000	\$ 1,200,000
Equipment Sales Price	\$ 5,780,000	\$ 7,780,000
Installation Cost	\$ 1,725,000	\$ 2,300,000
Total Installed Cost	\$ 7,505,000	\$ 10,080,000
Sales Price used	\$ 7,500,000	\$ 10,000,000
OPEX		
Consumables	\$ 100,000	\$100,000
Manpower	\$ 500,000	\$ 500,000

Table 3: Cost Estimation

6.3 California

Parameters	Units	Spill Back / Y-Grade	Spill Back / 9 psia NGL	End Spike / Y-Grade	End Spike / 9 psia NGL
Inlet Gas	MMSCFD	4.5	4.5	4.5	4.5
Sales Gas	MMSCFD	3.496	3.135	3.585	3.8
LHV - Sales Gas	Btu/scf	1015	1013	1027	<u>1152</u>
Dew Point - Sales Gas	°F	-0.952	-1.0844	6.75	<u>64.445</u>
Y-Grade	SBPD	399.8		377	
Stabilized NGL	SBPD		51.53		44.75
TVP	psig	100		100	
RVP	psia		9		9
G/G	MMBtu/hr	0.4288	0.4335	0.37	0.37
Chiller	MMBtu/hr	0.8898	<u>20.17</u>	0.77	0.77
LTS Temp	°F	5	5	5	5
Reboiler	MMBtu/hr	0.38	0.014	0.32	0.79
Refrig	HP	225.1	<u>5109</u>	195	195
Booster	HP	69.36	<u>4847</u>	56	105

LHV Tower ovhd	Btu/scf	1317	2130	1276	2112
Tower ovhd flow	MMSCFD	0.65	<u>46.65</u>	0.5081	0.9765
C ₃ + Recovery in NGL		77%	11.70%	73%	10%

Table 4: California Case Study Summary

Discussion

Spill Back with Stabilized NGL is not suitable due to excessive refrigeration duty, booster duty, and high tower overhead flowrate. This suggests that C₃/C₄ components remain trapped, disrupting system equilibrium.

Viable configurations include:

- Spill Back with Y-Grade
- End Spike with Y-Grade
- End Spike with Stabilized NGL

End Spike with Stabilized NGL requires adjustment of LTS temperature to meet acceptable sales gas LHV, as shown in the table below.

Parameters	Spill Back / Y-Grade	End Spike / Y-Grade	End Spike / 9 psia NGL
Gas Revenue	\$3,885,500	\$4,031,500	\$4,793,500
Y-Grade Revenue	\$3,357,000	\$3,166,000	
9 psia NGL Revenue			\$898,500
Total Revenue	\$7,242,500	\$7,197,500	\$5,692,000
Expense			
CAPEX	\$7,500,000.00	\$7,500,000.00	\$7,500,000.00
OPEX	\$600,000.00	\$600,000.00	\$600,000.00
Payback Period			
Calculated in Months	26	26	30

Table 5: California Payback Calculation

Summary for California case

The analysis shows that Spill Back with Y-Grade and End Spike with Y-Grade configurations provide the most favorable economics, achieving payback in approximately 26-months. In comparison, End Spike with 9 psia NGL results in a longer payback of about 30-months, primarily due to reduced NGL recovery and lower overall revenue. Meanwhile, Spill Back with Stabilized NGL is excluded from consideration, as the configuration leads to unsustainable compressor and refrigeration loads that compromise system stability and economic viability.

6.4 Utah

Parameters	Units	Spill Back / Y-Grade	Spill Back / 9 psia NGL	End Spike / Y-Grade	End Spike / 9 psia NGL
Inlet Gas	MMSCFD	25.15	25.15	25.15	25.15
Sales Gas	MMSCFD	<u>5.25</u>	<u>4.096</u>	<u>5.5</u>	<u>5.705</u>

LHV - Sales Gas	Btu/scf	<u>1138</u>	1082	1188	<u>1321</u>
Dew Point - Sales Gas	°F	3.7911	4.25	23.15	63.905
Y-Grade	SBPD	2256		2120	
Stabilized NGL	SBPD		<u>3.3</u>		<u>2.717</u>
TVP	Psig	100		100	
RVP	Psia		9		9
G/G	MMBtu/hr	0.71	0.44	0.59	0.6
Chiller	MMBtu/hr	4.9	<u>20.57</u>	4.197	4.2
LTS Temp	°F	5	5	5	5
reboiler	MMBtu/hr	2.1	0.52	1.572	<u>4.4</u>
Refrig	HP	1085	<u>4561</u>	930	930
Booster	HP	267	<u>4899</u>	177.6	<u>453</u>
LHV Tower ovhd	Btu/scf	1682	2676	1620	2677
Tower ovhd flow	MMSCFD	2.45	<u>48.87</u>	1.493	4.381
C ₃ + Recovery in NGL		90%	<u>0.160%</u>	85%	<u>0.12%</u>

Table 6: Utah Case Study Summary

Discussion

Sales gas volumes in this case are significantly constrained, primarily due to the exceptionally high CO₂ content in the feed.

Configurations utilizing a stabilized condensate—whether End Spike or Spill Back—fail to yield a sustainable liquid product. The recovery is negligible, offering neither technical justification nor commercial value.

Given the C₃+ contribution to the liquid product, a Spill Back arrangement appears to be the more suitable configuration under these conditions.

With CO₂ levels as high as 65.2%, a membrane system alone cannot achieve the required specifications; therefore, an amine unit is incorporated upstream of the flare recovery system.

Parameters	Spill Back / Y-Grade	End Spike / Y-Grade	End Spike / 9 psia NGL
Gas Revenue	\$6,542,000	\$7,154,000	\$8,252,500
Y-Grade Revenue	\$18,945,000	\$17,803,500	
9 psia NGL Revenue			\$54,500
Total Revenue	\$25,487,000	\$24,957,000	\$8,307,000
Expense			
CAPEX – Additional Amine	\$30,000,000	\$30,000,000	\$30,000,000
CAPEX – HC recovery	\$7,500,000.00	\$7,500,000.00	\$7,500,000.00
OPEX	\$1,500,000.00	\$1,500,000	\$1,500,000.00
Payback Period			
Calculated in Months	37	37	84

Table 7: Utah Payback Calculation

Summary for Utah case

The Utah case highlights the impact of high CO₂ content on recovery economics and added OPEX on operating the Amine unit. Both Spill Back and End Spike with Y-Grade deliver strong margins, with effective payback periods of approximately 37-months once construction is included. In contrast, the End Spike with 9 psia NGL configuration performs poorly, extending payback to approximately 84-months due to negligible liquid recovery and reduced overall revenues.

6.5 Indonesia

Parameters	Units	Spill Back / Y-Grade	Spill Back / 9 psia NGL	End Spike / Y-Grade	End Spike / 9 psia NGL
Inlet Gas	MMSCFD	50.09	50.09	50.09	50.09
Sales Gas	MMSCFD	42.3	43.3	42.18	42.75
LHV - Sales Gas	Btu/scf	955	980.4	1044	1069
Dew Point - Sales Gas	°F	-3.2689	-3.9	2.0848	22.046
Y-Grade	SBPD	458		629.6	
Stabilized NGL	SBPD		295.2		233.3
TVP	psig	100		100	
RVP	psia		9		9
G/G	MMBtu/hr	3.22	2.2	5.876	5.8
Chiller	MMBtu/hr	1.72	<u>5.2</u>	2.327	2.3
LTS Temp	°F	-5	-5	-5	-5
Reboiler	MMBtu/hr	0.2112	<u>8.8</u>	0.5	1.25
Refrig	HP	435	<u>1315</u>	588.9	588.9
Booster	HP	32	<u>744</u>	118	180.6
LHV Tower ovhd	Btu/scf	1246	<u>2770</u>	1022	1740
Tower ovhd flow	MMSCFD	0.165	<u>7.312</u>	0.9646	1.533
C ₃ + Recovery in NGL		28%	20%	37%	16%

Table 8: Indonesia Case Study Summary

Discussion

Markets in regions like Indonesia are more driven by oil and condensates than by natural gas or Y-Grade.

In such cases, an End Spike with Stabilized Condensate is generally the preferred option to meet market requirements.

Where Y-Grade pipeline infrastructure is available, End Spike with Y-Grade, followed by Spill Back with Y-Grade, becomes the most suitable configuration.

Spill Back arrangements may require modifications to the standard system, since stabilized NGL products typically achieve higher C₃+ recovery.

For the payback evaluation, sales gas revenue will not be considered due to infrastructure limitations at the facility.

Parameters	Spill Back / Y-Grade	End Spike / Y- Grade	End Spike / 9 psia NGL
Gas Revenue	N. A	N. A	N. A
Y-Grade Revenue	\$3,846,000	\$5,287,000	
9 psia NGL Revenue			\$4,683,500
Total Revenue	\$3,846,000	\$5,287,000	\$4,683,500
Expense			
CAPEX	\$30,000,000	\$30,000,000	\$30,000,000
OPEX	\$1,000,000	\$1,000,000	\$1,000,000
Payback Period			
Calculated in Months	138	96	110

Table 9: Indonesia Payback Calculation

Summary for Indonesia Case

In Indonesia, where the market is driven more by oil and condensates than by natural gas or Y-Grade, an End Spike with Stabilized Condensate is generally preferred. Where Y-Grade pipeline infrastructure exists, End Spike with Y-Grade is optimal, followed by Spill Back with Y-Grade. Spill Back arrangements may require adjustments due to higher C₃+ recovery in stabilized NGL. For payback evaluation, sales gas revenue is excluded due to infrastructure limitations, resulting in longer payback periods: End Spike with Y-Grade ≈ 8 years, End Spike with 9 psia NGL ≈ 9 years, and Spill Back with Y-Grade ≈ 11.5 years.

6.6 Oman

Parameters	Units	Spill Back / Y-Grade	Spill Back / 9 psia NGL	End Spike / Y-Grade	End Spike / 9 psia NGL
Inlet Gas	MMSCFD	12.11	12.11	12.11	12.11
Sales Gas	MMSCFD	8.65	8.278	9.065	9.483
LHV - Sales Gas	Btu/scf	979	994.3	1001	1088
Dew Point - Sales Gas	°F	8.25	7.69	25.771	47.183
Y-Grade	SBPD	1182		1045	
Stabilized NGL	SBPD		420		368.5
TVP	psig	100		100	
RVP	psia		9		9
G/G	MMBtu/hr	1.32	0.867	1.235	1.235
Chiller	MMBtu/hr	3.26	<u>34</u>	2.787	2.78
LTS Temp	°F	5	5	5	5
Reboiler	MMBtu/hr	0.75	<u>66</u>	0.538	1.77
Refrig	HP	615	<u>6423</u>	525	525
Booster	HP	165	<u>8175</u>	120	220
LHV Tower ovhd	Btu/scf	1406	2150	1381	2062
Tower ovhd flow	MMSCFD	1.756	<u>87.03</u>	1.254	2.235
C ₃ + Recovery in NGL		76%	31%	67%	27%

Table 10: Oman Case Study Summary

Discussion

This case is particularly interesting as it combines features of the Californian and Indonesian gas scenarios.

Evaluations indicate that Spill Back with Y-Grade followed by End Spike with Y-Grade would yield more economical products. However, the regional market favors the End Spike with Stabilized NGL option, as Y-Grade is often not the preferred product locally.

A Spill Back configuration with a Stabilized NGL product is not suitable due to high refrigeration duty, booster compressor load, and tower overhead gas flowrate. This suggests accumulation of C₃s and C₄s in the system, requiring purging and disrupting equilibrium, similar to observations in the Californian case study.

Parameters	Spill Back / Y-Grade	End Spike / Y-Grade	End Spike /9 psia NGL
Gas Revenue	\$9,273,000	\$9,936,000	\$11,297,500
Y-Grade Revenue	\$9,926,000	\$8,775,500	
9 psia NGL Revenue			\$7,397,500
Total Revenue	\$19,199,000	\$18,711,500	\$18,695,000
Expense			
CAPEX	\$10,000,000.00	\$10,000,000.00	\$10,000,000.00
OPEX	\$6,000,000.00	\$600,000.00	\$600,000.00
Payback Period			
Calculated in Months	19	19	19

Table 11: Oman Payback Calculation

Summary for Oman case

This case combines characteristics of both the Californian and Indonesian gas scenarios. Evaluations show that Spill Back with Y-Grade followed by End Spike with Y-Grade would yield the most economical products. However, the local market favors the End Spike with Stabilized NGL option, as Y-Grade is often not preferred in the region. A Spill Back configuration with Stabilized NGL is not feasible due to excessive refrigeration duty, high booster compressor load, and large tower overhead flow, which can cause accumulation of C₃s and C₄s and disrupt system equilibrium, consistent with findings in the Californian case study. All configurations in this case demonstrate attractive payback periods of approximately 19-months, reflecting strong economic viability.

6.7 West Texas

Parameters	Units	Spill Back / Y-Grade	Spill Back / 9 psia NGL	End Spike / Y-Grade	End Spike / 9 psia NGL
Inlet Gas	MMSCFD	2.6	2.6	2.6	2.6
Sales Gas	MMSCFD	1.4	0.99	2.084	2.399
LHV - Sales Gas	Btu/scf	1074	1040	<u>1219</u>	<u>1340</u>
Dew Point - Sales Gas	°F	-1.23	-4.45	35.6	83.9
Y-Grade	SBPD	249		212	
Stabilized NGL	SBPD		10.27		9
TVP	psig	100		100	
RVP	psia		9		9
G/G	MMBtu/hr	0.26	0.183	0.165	0.2
Chiller	MMBtu/hr	<u>20</u>	<u>31.63</u>	1.2	0.87
LTS Temp	°F	-15	-15	-15	15
Reboiler	MMBtu/hr	<u>11.16</u>	22.4	0.34	0.45
Refrig	HP	<u>5083</u>	<u>7681</u>	290	145
Booster	HP	<u>2266</u>	<u>3625</u>	80	75
LHV Tower ovhd	Btu/scf	1523	1738	1436	1926
Tower ovhd flow	MMSCFD	<u>33.73</u>	<u>47.55</u>	1.134	0.97
C ₃ + Recovery in NGL		73%	35%	62%	32%

Table 12: West Texas Case Study Summary

Discussion

The low-pressure flashed gas in West Texas requires the optional Inlet Booster Compressor.

A Spill Back configuration is unsuitable for this high C₃+ scenario, as a large portion of C₃ and C₄ remains in the system without being recovered in either the gas or liquid streams.

Therefore, an End Spike arrangement is more appropriate for this case.

End Spike configurations for Y-Grade and Stabilized NGL use different LTS temperatures to illustrate the impact of LTS adjustments on calorific values.

The most effective solution in West Texas is to avoid blending the tower overheads back into the inlet or outlet. Instead, directing them to the Power Generation system, blended with CO₂-rich membrane reject, would be particularly advantageous. This option is not shown in the table to maintain consistency across all case studies.

Parameters	Spill Back / Y-Grade	End Spike / Y-Grade	End Spike / 9 psia NGL
Gas Revenue	\$2,474,000	\$2,659,000	\$3,319,000
Y-Grade Revenue	\$1,831,500	\$1,679,500	
9 psia NGL Revenue			\$189,500
Total Revenue	\$4,305,500	\$4,338,500	\$3,508,500

Expense			
CAPEX – Compression	\$1,500,000.00	\$1,500,000.00	\$1,500,000.00
CAPEX – HC Recovery	\$7,500,000.00	\$7,500,000.00	\$7,500,000.00
OPEX	\$600,000.00	\$600,000.00	\$600,000.00
Payback Period			
Calculated in Months	41	41	49

Table 13: West Texas Payback Calculation

Summary for West Texas case

In West Texas, the low-pressure flashed gas scenario requires the optional Inlet Booster Compressor, and the high C₃+ content makes a Spill Back configuration unsuitable, as significant C₃ and C₄ remain unutilized in the system. An End Spike arrangement is more appropriate, with Y-Grade and Stabilized NGL cases using different LTS temperatures to demonstrate the effect on calorific values. The most effective approach is to avoid blending tower overheads back into the system, instead sending them directly to the Power Generation module, potentially blended with CO₂-rich membrane reject, though this is not reflected in the table for consistency. Economically, End Spike configurations offer payback periods of ~41-months for Y-Grade and ~49-months for 9 psia Stabilized NGL, with total revenues ranging from \$3.5M to \$4.34M and capital plus operating expenses considered.

6.8 Conclusion

Modular flare gas recovery systems offer a versatile and scalable solution to transform routine flaring into valuable products and energy. By combining Gas Treating/Conditioning, Recycle Compression, Membrane Skids, and Power Generation—with optional modules such as Inlet Boosters—these systems can be tailored to diverse site conditions, including low-pressure streams, high C₃+ content, or elevated CO₂ levels. Case studies demonstrate that the optimal configuration depends on gas composition, pressure, and market infrastructure, with End Spike arrangements often suited for high C₃+ or power-focused applications, and Spill Back favorable where pipeline access supports higher liquid recovery. Economically, payback periods vary by location and configuration, ranging from as short as 19-months to longer periods in more challenging scenarios, highlighting the flexibility and adaptability of the modular approach. Overall, these systems present a sustainable and profitable pathway to reduce emissions, recover hydrocarbons, and generate energy and revenue from previously wasted resources.

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