Reduce Emissions for Compressor Stations in Condensate-rich Shale Gas Plays by Reducing Heavy Hydrocarbons in Fuel Gas

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ABSTRACT

In many shale-gas plays, especially wet- and/or condensate-rich shale gas plays, only raw and heavy shale gas is available as fuel for compressor drives and power generation turbines. As a result of the considerable richness (High Btu Value) of the raw gas in such shale-gas plays, operators are finding it increasingly challenging to meet the regulatory requirements on the emissions levels for the local compressor stations apart from having to run their engines running on substantial de-rates especially for the larger HP range machines. In addition, heavy hydrocarbons rich gas can damage or foul engine components, causing mechanical reliability issues & reduced compressor/engine efficiencies, even leading to engine or turbine shutdown. The immediate impact of this is loss of gas and oil production until the components are replaced or fixed. This paper describes the use of unique reverse-selective membranes which preferentially removes heavy hydrocarbons components from the raw shale-gas to produce clean fuel gas at these sites. Numerous fuel gas conditioning units have been installed in several shale-gas plays across the country by companies like EQT Midstream (Marcellus and Devonian), Peregrine Pipeline (Barnett Shale) and in the Eagle Ford shale area for reducing the heavy & sour contents from the fuel gas & subsequently also meet the emissions requirement on the VOC levels. These systems have no moving parts, are designed for simple, unattended operation and are virtually maintenance-free.

By effectively reducing the heavy hydrocarbons content, Membrane Fuel Gas Conditioning Units reduces the volume of unburned VOC's emissions caused due to incomplete combustion of hydrocarbons in the firing chamber. These units have been used to fix derate and high maintenance problems due to poor fuel gas quality for Wartsila, Caterpillar, Waukesha, Superior and other reciprocating engine makers and also for turbine fuel gas conditioning. Skids have been used to produce from 0.1 to 110 million scfd (MMscfd) of clean gas. Membrane Fuel Gas Conditioning Units are completely passive and the feed gas requires no pretreatment, except for standard filtration. Practical cases of how these units have helped in resolving issues with problematic fuel gas will be discussed in the paper.

INTRODUCTION

Raw unprocessed natural gas is widely used to power field turbines and engines that drive compressors or generate power. Compressor engine exhausts are a major source of a variety of strictly regulated emissions including NOx, CO, unburned non-methane hydrocarbons etc. Operators have to meet several stringent emissions requirements to remain within the thresholds of allowable emissions limits of the above mentioned components. The situation is highly aggravated when the raw fuel gas is rich in heavy hydrocarbons. High levels of heavy hydrocarbons content in the fuel gas are responsible for incomplete combustion and/or pre-detonation in the gas engines which lead to increased CO and unburned non-methane hydrocarbons emissions (NMHC) beyond the acceptable limits[1]. NOx emissions are also affected by high levels of heavy hydrocarbons due to the richer BTU content of the fuel gas.

Oftentimes the raw gas composition does not meet the minimum requirements of engine or turbine suppliers. An excess of ethane, propane and C_{4+} hydrocarbons results in too low a methane number for gas engines, or too high a Wobbe Index for turbines. Specifically, high levels of heavy hydrocarbon components lead to pre-detonation in reciprocating gas engines. This requires derating of the engines so that they can run smoothly. In turbines, coking on the nozzles and in the combustion chamber leads to reduced efficiencies due to fouling or damage to the blades. In both gas engines and turbines, increased emissions of unburned VOCs will result if the inlet gas is too rich.

Presence of high levels of sulfur, especially H_2S, in the fuel gas directly impacts the SOx emissions. Sour fuel gas containing sizeable proportion of H_2S will lead to proportionately higher levels of SOx emissions. Apart from high SOx emissions levels, an excess of acid gases, specifically carbon dioxide or hydrogen sulfide, can corrode engine and turbine components, increasing maintenance needs and resulting in unscheduled downtime. The amount of gas used by field engines is usually in the 0.5 to 5.0 MMscfd range—too small to make treatment of the gas by conventional amine-based technology economical. As a consequence, many engine users are forced either to live with the problem gas and the resulting low reliability and high maintenance costs, or to install costly-to-operate chemical scavenging systems.

The above-described problems can be ameliorated by processing the gas using a special type of membrane that is more permeable to heavy hydrocarbons and acid gases than to methane. Early work in this area was performed at Phillips Petroleum almost thirty years ago.[2] Over the last few years, one company, Membrane Technology and Research, Inc. (MTR), of Menlo Park, CA, has developed commercial systems and processes incorporating specialized membrane technology to treat heavy or sour fuel gas streams[3]. The process, known as FuelSep™, is in use at a number of sites and for a variety of upstream fuel gas streams. To date, these membranes have been installed at more than sixty sites for heavy hydrocarbons separation from natural gas. Skid–mounted compact membrane units make the FuelSep™ process particularly suitable for remote wellheads and compression stations where high levels of heavy hydrocarbons present in the fuel gas are reduced significantly to remain within the emissions threshold limits. This paper describes and compares two case studies and process configurations.

MEMBRANE BACKGROUND

In the mid-1980s, membrane systems to remove carbon dioxide were introduced to the natural gas processing industry. These membranes separate gases primarily by molecular size. They permeate the small carbon dioxide molecules faster than the relatively larger methane molecules, but retain the even larger heavy hydrocarbon molecules in the gas stream. In contrast, recent advances in membrane technology have allowed development of membranes that utilize differences in gas solubility to permeate heavy hydrocarbons, carbon dioxide and water vapor simultaneously though the membrane.

HOW MEMBRANES WORK

Membranes used to filter liquids are often finely microporous, but membranes used to separate gases have only transient pores so small they are within the range of the thermal motion of the polymer chains that make up the selective polymer layer. Permeation through gas separation membranes is therefore best described by a process called solution-diffusion. Gas molecules dissolve in the polymer membrane as in a liquid and then diffuse across the membrane and then desorb from the polymer on the opposite interface which is typically maintained at a lower pressure as compared to the feed. The rate of gas permeation is a product of a solution term (how many molecules dissolve in the membrane), and a diffusion term (how fast each individual molecule diffuses across the membrane). Fuel gas-conditioning membranes are chosen from materials that maximize the effect of the solution term. Although each individual molecule of butane, for example, diffuses more slowly across the membrane than each individual molecule of methane, the very high solubility of butane more than compensates for the slower diffusion. Fuel gas conditioning membranes therefore preferentially permeate water, carbon dioxide, hydrogen sulfide, C_{2+} hydrocarbons and BTEX aromatics, while retaining methane. Because most of us are familiar with conventional filtration, this result feels counter-intuitive. Nevertheless, these unique properties are what make the membranes particularly useful in fuel gas conditioning applications.

MEMBRANE STRUCTURE

Membranes used to separate heavy hydrocarbons from natural gas typically have multilayer composite structures of the type shown in Figure 1. Composite membranes are used because the optimum materials for performing the separation are rubbery polymers, which are mechanically weak. Furthermore, to obtain high permeation rates, the selective membrane must be very thin, typically between 0.5 and 5.0 µm thick. Finally, the membrane must be able to support a pressure differential of 200 to 1,500 psi.

Even though composite membranes have extremely thin selective layers, many square meters of membrane are required to separate a useful amount of gas. The units into which large areas of membrane are packaged are called membrane modules. In the FuelSep™ process, spiral-wound membrane modules of the type illustrated in Figure 1 are used. The membranes are formed into a sealed membrane envelope, and then, with appropriate feed and permeate channel spacer netting, are wound around a perforated central collection pipe. The module is placed inside a tubular pressure vessel. One to six modules may be connected in series within each pipe. Pressurized feed gas passes axially down the module, across the membrane envelope on the feed side. A selective portion of the feed permeates into the membrane envelope, where it spirals towards the center and is collected through the perforated permeate collection pipe. The treated gas is withdrawn from the feed side at the residue end of the module.

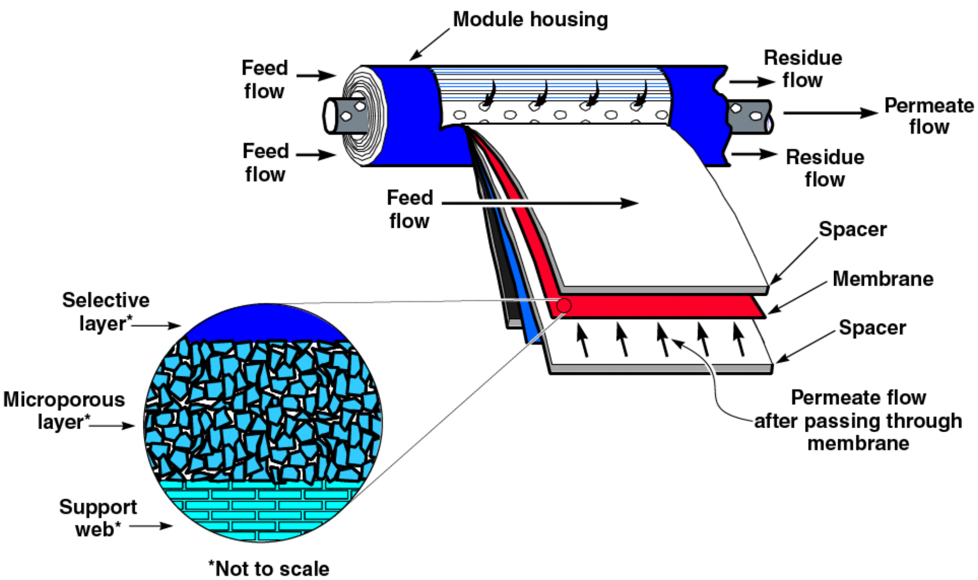

Figure 1. Schematic illustrations of a composite membrane and a spiral-wound module of the type used in fuel gas conditioning units.

ADVANTAGES

The key advantages of a membrane FGCU can be summarized thus:

- **Simple, passive system**
- **High on-stream factor (typically >99%)**
- **Ambient temperature operations**
- **Minimal or no operator attention**
- **Small footprint with low weight**
- **Large turndown ratio**
- **Rapid start up and shut down**
- **Low maintenance**
- **Low capital and operating costs**
- **Units are mobile and can be redeployed to other locations**
- **Handles fluctuating feed gas compositions**

A membrane FGCU is completely passive, has no moving parts, and requires no chemicals to operate. Units are skid-mounted and can be installed wherever a reasonably level patch of gravel or soil can be provided, without needing a permanent foundation. Normally, a skid will operate in one location for months or years, but skids are very robust, and can be trucked to a new site if circumstances change.

FuelSep™ can be used as a stand-alone operation to process gas streams from as low as 0.1 MMscfd to upwards of 100 MM scfd. In most upstream applications, fuel gas flowrates can be between 0.05 MMSCFD for a single genset up-to 5 MMSCFD for a large compressor station. The feed gas requires no pretreatment, except for standard filtration. The membranes operate near ambient temperatures and in most cases no separate dehydration or hydrate control is required. There is no accumulated liquid in the system, so there is no risk of pool fires or need to dispose of or store liquids. A single stage system can reach steady state performance within a few minutes of startup, and can be fully automated and remotely monitored, so that it can run unattended. Little or no maintenance is needed.

For common applications, the fuel gas is constantly rich and needs to be processed continuously. From time to time, however, the issue is not continuously rich gas, but rapid fluctuations of the BTU value due to process or pipeline upsets upstream of the fuel source. For such cases, the FuelSep™ process employs a “Quick-Blend” feature - a simple but robust control strategy to ensure that any variations in BTU level are absorbed essentially instantaneously, so that steady state is restored before any damage has been done. Changes in the inlet gas composition immediately change the membrane separation performance, so that the membrane process acts as a capacitance, muting down swings in gas quality. Quick-Blend results in a continuous and smooth delivery of clean conditioned fuel gas at an acceptable range of BTU values.

CASE STUDIES

I. Higher BTU (Hot Gas) or Heavy Hydrocarbon Rich Fuel Gas for Gas Engines

A typical membrane Fuel Gas Conditioning Unit (FGCU) installed for a client in the Eagle Ford Shale, TX is shown in Figure 2. Client was planning to install a natural gas fired compressor to compress gas to a higher pressure for moving gas into the sales pipeline. Due to the remote location of the compressor-site, the raw gas available was the only source of fuel gas for the gas engines driving the compressors. The raw gas was extremely rich, containing more than 20% C_{2+} hydrocarbons & a LHV of 1161 Btu/Scf.

Issues Faced By Client

Due to the substantially high levels of heavy hydrocarbons in the fuel gas, the client foresaw a series of potential difficulties in operating the large gas engines at this site, which are listed below:

a. Engines Cannot be Started -

   The raw gas available for fuel was so rich in heavy hydrocarbons, that the client was unable to even start the engines, hence unable to move the raw gas into the sales gas pipeline resulting in an in-ability to flow the field and therefore a loss in revenues.

b. Knocking-Detonation Issues –

   The raw fuel gas would have caused operational issues related to knocking, detonation etc. leading to increased wear & tear of the engine components and increased maintenance costs.

c. Engine Warranties Violation –

   The engine manufacturer’s warranties were tied to a max BTU limit of 1050 BTU/SCF on the LHV of the fuel gas; and, if the client were to use the engines with the high BTU raw fuel gas, then it would have immediately nullified their engine warranties.

d. Emissions Non-Compliance –

   The significantly high content of heavy hydrocarbons meant high levels of emissions from the engines exhaust. This would have potentially resulted in non-compliance with the emissions regulations for the NOx, CO and unburned hydrocarbon.

Options Evaluated By Client

In order to resolve the above issues, the client evaluated various options listed below (Table 1):

a. JT Process
   A JT process works on the simple principle of pressure reduction to achieve low temperature thereby dropping liquids and lowering the BTU content of the fuel gas. Low temperatures, however, can result in the formation of hydrates in the fuel line. A methanol injection system was then required to avoid any hydrate issues. In addition, the liquids formation poses various hassles including storage, handling and emissions from the storage tanks which may require additional permitting. Finally, a simple pressure reduction, although reduces the C4+ content, but is just not sufficient to condense and remove C2/C3 (propane/ethane) components which are major contributor to the BTU content of the fuel gas. Keeping in mind, all these issues, JT process was deemed unfeasible to meet the client's requirements at this site.

b. Refrigeration
   Refrigeration also presented with the same set of issues as of JT, related to liquids formation: low temperatures, hydrates issues, emissions etc. In addition, refrigeration is a more complex process with moving parts and may also require special permitting if required to classify it as a process. Also, it is challenging to remove C2/C3 which requires very low temperatures to condense out especially ethane.

c. Membranes
   Membranes, on the other hand, do not generate any liquids thereby eliminating any issues related to liquids storage, handling, emissions permitting, hydrates formation etc. In addition to lowering the C4+ components of the fuel gas, membranes also significantly reduce the ethane content which further lowers the BTU content of the fuel gas.

Based on the above discussed factors and the overall simplicity of the membrane process, the client decided to install a membrane unit for conditioning the fuel gas for their compressor fuel.

Table 1. Comparative Evaluation Matrix for JT, Refrigeration and Membrane processes.

	JT Process	Refrigeration	Membranes
Low Temps – Hydrate Issues	**Yes**	**Yes**	**No**
Reduce C2/C3	**No**	**No**	**Yes**
Liquids Storage – Emissions – Permitting Required	**Yes**	**Yes**	**No**
Moving Parts	**-**	**Yes**	**No**
Classified as Process	**-**	**Yes**	**-**
Requires Special Permitting	**-**	**Yes Likely**	**-**

Membrane Fuel Gas Conditioning Unit

A. Technical Details

Process - MTR's membrane fuel gas conditioning unit was installed to reduce the heavy hydrocarbons and thereby reduce emissions and remain within the emissions thresholds. Figure 2 shows the process schematic for the fuel gas conditioning scheme. The treated gas supplies fuel to a compressor station containing multiple Caterpillar engines. A slipstream is taken from the compressor discharge pipeline between 915 – 1190 psia and passed across the feed side of the FGCU. Methane is retained preferentially on the feed side; C_{2+} hydrocarbons and BTEX aromatics permeate preferentially. The low-pressure permeate gas, enriched in heavy hydrocarbons, is re-circulated to the suction side of the compressor. The conditioned gas, stripped of these components, is used to fuel the engine.

System Size - The membrane unit (shown in Figure 2) consists of a single vessel (horizontal) containing multiple membrane modules. The membrane vessel is designed to generate a max fuel flow-rate of 1.0 MMscfd at a Btu level of 1050 BTU/SCF on the LHV. A single vertical filter coalescer (seen at the back in Fig. 2) serves to remove any liquids, fine mist or aerosols from the feed gas entering the membranes.

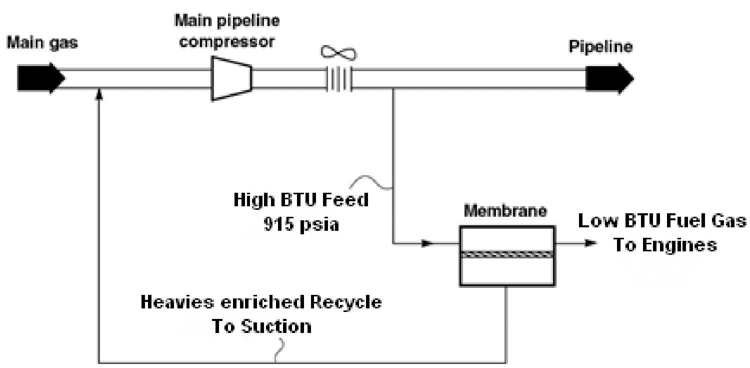

Figure 2. Block diagram and photograph of a membrane FGCU used for a gas gathering compressor engine in the Eagle Ford Shale, TX. The membrane modules are contained in the horizontal pressure

vessel. The unit can produce 0.5 to 1.0 MMscfd of conditioned gas.

B. Field Operational Data

Gas Composition – BTU Reduction

Table 2 shows actual field data for the gas compositions of raw gas entering and exiting the membranes. The membrane unit lowers the Low Heating Value (LHV) of the feed gas from 1,161 Btu/Scf to 960 Btu/Scf and thereby helping to be within the allowable limits for maintaining the warranties on the gas engines. Additionally, the lowering of the BTU value in the fuel gas also allowed the compressor engines to be tuned within acceptable parameters to avoid any detonation issues. The methane number of the fuel gas was significantly improved to 79 in the process of removing the heavy hydrocarbons. It is also important to note that both ethane and propane content were significantly reduced by the membrane process, while C4+ components were significantly lowered in concentrations (Table 2).

Table 2. Performance Data for a membrane FGCU used for a gas gathering compressor engine in the Eagle Ford Shale, TX.

Stream	Feed Gas	Conditioned Gas
Methane Number	47	79
LHV(Btu/scf)	1161	960
HHV (Btu/scf)	1280	1063
Component (mol%)		
Nitrogen (N_2)	0.19	0.33
Carbon Dioxide (CO_2)	0.36	0.23
Methane (C1)	77.4	94.03
Ethane (C2)	13.26	4.04
Propane (C3)	5.19	0.88
Butanes (C4)	2.46	0.34
Pentanes (C5)	0.74	0.11
Hexanes plus (C6+)	0.40	0.05

Emissions Reduction

Ideally, the effects of membrane conditioning on emissions reduction could have been verified by directly comparing the on-site field emissions results of the raw gas entering the membranes and conditioned fuel gas exiting it. However, as the client was unable to even start the engines on the raw gas (due to the high BTU value), on-site field emissions data for the gas engines running on raw gas was not available. Hence, the emissions data for the raw gas was obtained *indirectly* by utilizing a software program (from a leading engine manufacturer) for running a site rating calculation. Emissions data computed by the same site rating program on the conditioned fuel gas showed a significant reduction in the non-methane hydrocarbons (NMHC) emissions which dropped down from 1168 ppm in the raw feed gas to 409 ppm in the conditioned fuel gas (Table 3). This reduction in the emissions was amply verified by the on-site field emissions data on the conditioned fuel gas which showed the NMHC emissions reduced down to non-detectable levels after membrane conditioning.

Table 3 shows the on-site field NOx and CO emissions for the conditioned fuel gas are well within the allowable emission rates (per 40CFR60 subpart JJJJ), and non methane hydrocarbon emissions are reduced down to non-detectable levels. Thus, reducing the heavy hydrocarbons content in the fuel gas using membranes helped the operator to stay within the allowable emission limits for gas engines.

Table 3. Emissions Data for a membrane FGCU used for a gas gathering compressor engine in the Eagle Ford Shale, TX.

Parameter	**Raw Feed Gas**	**Conditioned Fuel Gas**	
Methane Number	47	79.8	
LHV (BTU/scf)	1161	960	
Engines Emissions Data	**Program Calculated** *Site Rating*	**Program Calculated** *Site Rating*	**Actual Field Data**
NOx *(Max Allowable – 160 ppm)**	98	99	59
CO *(Max Allowable – 540 ppm)**	786	786	205
NMHC – *Non Methane Hydrocarbons* *(Max Allowable – 86 ppm)**	1168	409	Non-Detectable

* Allowable Emissions Rate per 40CFR60 Subpart JJJJ

C. Economic Analysis

Additional Condensate Recovery

The FuelSep™ Fuel Gas Conditioning Unit (FGCU) preferentially removes the heavy hydrocarbons from the fuel gas which are recovered back (in the vapor form) into the main pipeline by recycling these back to the compressor suction. These valuable heavy hydrocarbons can be recovered as additional liquid condensates - some of the condensates are recovered at the discharge scrubber of the compressor station, whereas the remaining condensates will be recovered at the downstream condensate recovery plant (Figure 3). This results in additional revenues leading to very attractive payback times for the MTR's FuelSep™ process. In the absence of the membrane system, these valuable heavy hydrocarbons are simply burned as raw fuel gas in the gas engines and hence lost.

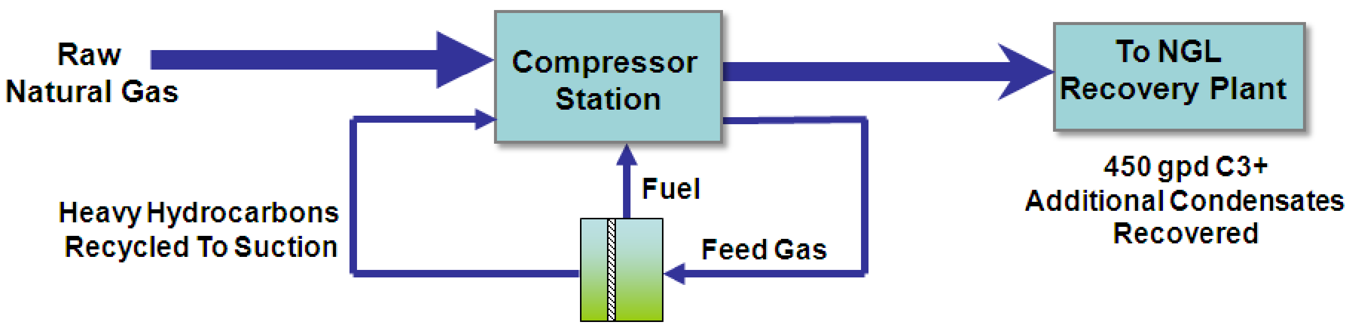

Figure 3. Block diagram of a membrane unit installed at a compressor station with a downstream NGL Recovery Plant.

Table 4. shows 450 gpd of additional C3+ are recovered amounting to approx $200,000/year of additional revenues. In the absence of MTR's Membrane unit, these heavy hydrocarbons are burnt as fuel gas & hence lost.

Table 4. Additional C3+ condensates recovered in the NGL plant due to membranes fuel gas conditioning.

	Raw Fuel Gas	Conditioned Fuel Gas	Total Condensates Sent to NGL Plant	$$$ Additional Revenues per year
C3+ Burned in Fuel (gpd)	532	82	450	$200,000

1. *Fuel Consumption – 0.2 MMscfd*
2. *NGL pricing - $ 50 bbl/d*

Increased Compression Capacity per Site

Typically, each compressor site has a cap on the allowable non-methane hydrocarbons (NMHC) emissions from a single site. This severely restricts the amount of gas compressed at a facility if the emissions from the gas engines exhaust are high due to the high BTU content of the fuel gas. By significantly reducing the emissions (by reducing the heavy hydrocarbons content of the fuel gas), the membrane unit allows the operator to compressor more gas and still remain within the max allowed NMHC emissions per site without triggering a PSD (Prevention of Significant Deterioration) which requires special permitting and extensive monitoring, reporting & related paperwork.

Table 5 indicates that due to the NMHC emissions being reduced down to non-detectable levels in the engines exhaust, the compressor station can utilize the maximum capacity of 11,900 hp by utilizing the conditioned fuel gas from the membranes. In the absence of the membranes, only 880 hp of compressor capacity could have been utilized with the engines running on the high BTU raw fuel gas. The client was able to free up an additional compressor capacity of approximately 11,000 hp by reducing his NMHC emissions by utilizing the membranes.

Table 5. Increased compression capacity per site due to the reduced NMHC emissions effected by the membranes.

	Raw Feed Gas	**Conditioned Fuel Gas**	
Engines Emissions Data	**Program Calculated** *Site Rating*	**Program Calculated** *Site Rating*	**Field Data**
NMHC *(Max Allowable – 86 ppm)*	1168	409	**Not Detectable**
Max Allowable hp per site without triggering PSD	880 HP[a]	2,500 HP[a]	**11,900 HP[b]**

[a]*Based on PSD (Prevention of Significant Deterioration) & Title V of the 1990 Clean Air Act Amendment, threshold levels of VOCs = 100 TPY*

[b]*Allowable Emissions Rate per 40CFR60 Subpart JJJJ of 86 ppm or 1 g/hp-hr for VOCs*

II. H_2S Contaminated Sour Fuel Gas for Gas Engines

Raw gas containing high levels of heavy hydrocarbons is very common; gas containing high levels of hydrogen sulfide is less common, but hydrogen sulfide is very corrosive and most equipment manufacturers specify a lower limit of hydrogen sulfide in fuel gas. High levels of H_2S in fuel gas also results into SOx emissions beyond the permissible limits leading to non-compliance with the emissions regulations for the operators. When hydrogen sulfide is the main contaminant, MTR's hydrogen sulfide-selective membranes can be used.

Dominion Exploration (now Bonavista Petroleum) needed 1.0 MMscfd of clean gas for three compressor engines and on-site heaters at a remote site in British Columbia, Canada. The available gas contained 3,400 ppm hydrogen sulfide—too high for the Caterpillar engines that were driving the compressors.

Issues Faced By Client

Due to the substantially high levels of H_2S in the fuel gas, the client foresaw a series of potential difficulties in operating the gas engines at this site, which are listed below:

a. Increased Maintenance –

   The client anticipated potentially increased wear and tear of the engine components caused by the high H_2S content of the raw fuel gas, eventually leading to increased maintenance costs & increased unscheduled maintenance cycles.

b. Engine Warranties Violation –

   The high H_2S content of 3400 ppm was significantly beyond the engine manufacturer's acceptable levels of the 100 ppm. The engines warranties would have been void if the engines were to be run on the existing high levels of H_2S in the raw feed gas.

c. High Sulfur Emissions –

   The high levels of H_2S in the raw fuel gas had a direct impact on the potential increase in sulfur emissions from the gas engines exhaust.

Options Evaluated By Client

In order to resolve the above issues, the client evaluated various options listed below:

a. Amine Unit
   Amine unit operates on the principle of contacting the sour gas with alkanolamine solution which is used as an absorption solvent in an amine tower. The operation requires the amine

solution to be maintained at fairly warm temperatures to maintain optimal removal efficiencies. As a result, the amine unit would have to be installed inside a heated building as a protection against the harsh cold winters (BC, Canada) resulting in significantly high capital costs (CAPEX). The amine unit operation also demanded a continuous operator attention.

b. Liquid Scavengers
Liquid scavenger was analyzed as a potential alternative for lowering the H_2S content in the raw fuel gas. Scavengers represent a recurring cost on a daily basis in addition to the on-site storing handling, and disposal costs. High levels of H_2S meant high rates of scavenger utilization and high operating costs (OPEX) which made this option an expensive proposition for the client to implement.

c. Membranes
Membranes does not require recurring consumables on a daily basis and provided a cost-effective solution for lowering the H_2S content in the raw fuel gas; and hence was adopted as the technology of choice by the client for reducing the H_2S content from the sour fuel gas. The installed cost of the membrane unit was calculated to be less than one year's chemical scavenger costs.

Membrane Fuel Gas Conditioning Unit

A. Technical Details

Process - Figure 4 shows the process schematic for the fuel gas conditioning scheme. A slipstream is taken from the compressor discharge pipeline at a high pressure and passed across the feed side of the FGCU. Methane is retained preferentially on the feed side; H_2S and C_{2+} hydrocarbons permeate preferentially. The low-pressure permeate gas, enriched in heavy hydrocarbons and H_2S, is re-circulated to the suction side of the compressor. The conditioned gas, stripped of these components, is used to fuel the engines.

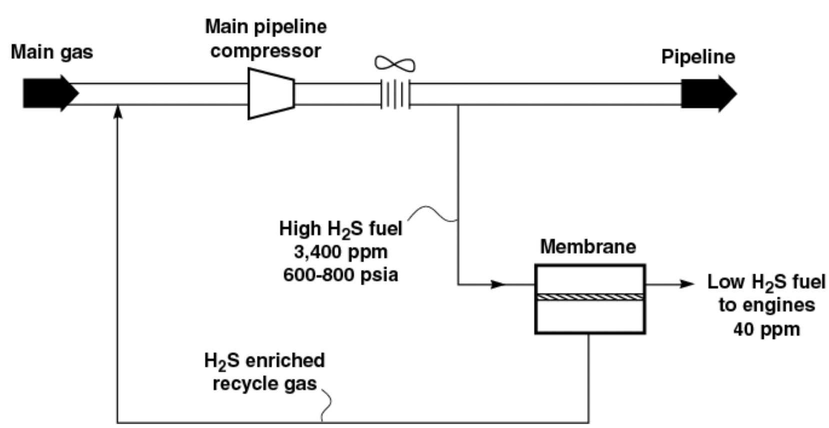

Figure 4. Block flow diagram and photograph of FGCU designed to treat high H_2S-content gas.

System Size - The membrane unit (shown in Fig. 5) consists of four vessels containing multiple membrane modules. Two vessels are online and two vessels are on stand-by & provide 100% redundancy. Each membrane vessel is designed to generate a max fuel flow-rate of 1.0 MMscfd of conditioned fuel gas.

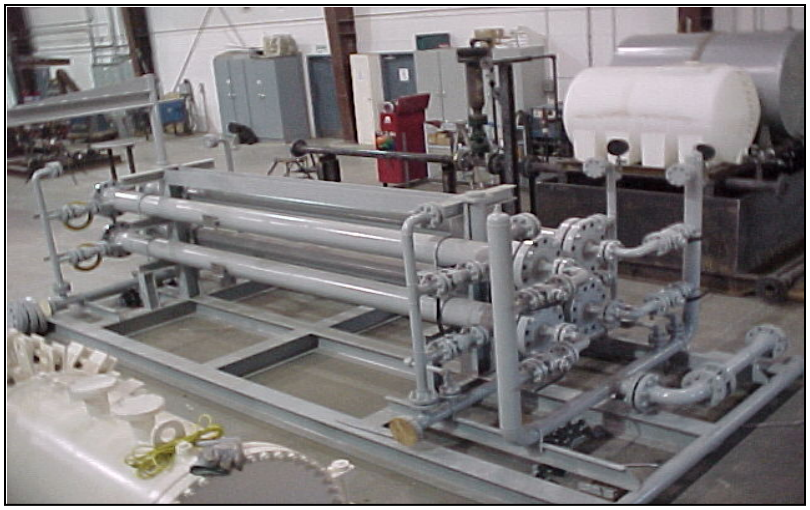

Figure 5. Photograph of FGCU designed to treat high hydrogen sulfide-content gas. Skid mounted with four horizontal pressure vessels shown in the photograph.

B. Field Operational Data

Gas Composition – H_2S & Emissions Reduction

Table 6 shows a significant reduction in the H_2S content of the fuel gas from 3,400 ppm down to 40 ppm. Total sulfur emissions were also lowered significantly from 48 TPY (tones per year) in the raw sour gas down to less than 2 TPY in the conditioned fuel gas.

An important feature is that the membrane FGCU removes hydrogen sulfide and heavy hydrocarbons simultaneously. Operators report that using the unit has extended the mean time between overhauls of the Caterpillar engines over those normally recommended. This surprising result may be attributable to the fact that the fuel gas quality is greatly improved over normal field natural gas. The unit was placed in operation in 2004, and no membrane replacement has been required to date.

Table 6. Design Performance of an FGCU to Remove Hydrogen Sulfide and Heavy Hydrocarbons.

Component	Feed Gas (mol %)	Conditioned Gas (mol %)
Propane	2.72	0.624
Isobutane	0.37	0.049
n-Butane	0.67	0.088
Isopentane	0.18	0.018
n-Pentane	0.19	0.019
Hexane	0.16	0.010
C_{6+}	0.14	0.008
Total C_{3+} hydrocarbons	**4.43**	**0.82**
Hydrogen sulfide	**3400 ppm**	**< 100 ppm**
Sulfur Burned in Fuel Tonnes Per Year (TPY) Sox Emissions	**48 TPY**	**< 2 TPY**

CONCLUSIONS

Poor quality fuel gas is a common problem for operators of engines and turbines in remote locations. Membrane systems offer a simple and economical solution to this problem, enabling operators to comply with the stringent emissions limits on engine exhaust, and at the same time providing higher reliability and online operating time, while reducing maintenance costs. To summarize, the FuelSep™ Membrane fuel gas conditioning units offer the following advantages:

- **BTU Reduction -** Significantly reduces the heavy hydrocarbons from condensate-rich raw feed gas and provides conditioned Low BTU fuel gas to the gas engines driving the compressors.
- **Emissions Reduction -** Substantially reduces the emissions from the gas engines exhaust due to the reduced BTU content of the fuel gas.
- **Additional Condensate Recovery –** Provides quick payback times due to the added value of the heavy hydrocarbons recycled back to the pipeline and recovered in the downstream NGL plant.
- **Increased Compression HP per site-** By reducing the VOC emissions from the gas engines, operator can utilize additional compression hp at the site to compress more gas and still remain within the max allowable emissions per site without triggering a PSD.
- **H_2S Reduction –** Significantly reduces sour gas components like H_2S & CO_2 (along with heavy hydrocarbons) from fuel gas and thereby reducing the SOx emissions from gas engine exhausts.

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