Advances in Membrane Materials Provide New Solutions in the Gas Business

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Abstract:

For most of the 20 years in which gas separation membranes have been commercially available, their application in natural gas processing has been mostly limited to CO_2 removal. Recent improvements in membrane technology have enabled membranes to be competitive in other separations in the natural gas area for the first time. This paper describes these new developments, which will significantly increase the range of use of membranes in the gas patch. The new membrane materials and configurations not only exhibit superior performance, but also offer improved stability against common contaminants found in natural gas.

New membrane processes are targeted at three separations: nitrogen, CO_2 /H_2S and NGL. For nitrogen removal from natural gas, commercially proven membranes are beginning to be used to separate hydrocarbons from nitrogen. The NitroSep™ process using these membranes will allow production from currently shut-in high-nitrogen gas reserves.

For NGL removal and recovery, a membrane similar to the NitroSep membrane can be used to preferentially permeate heavy hydrocarbons, allowing conditioning of fuel gas, dewpoint adjustment and oil vapor recovery.

For CO_2 removal, a new membrane termed Z-Top™, based on Teflon chemistry, has been extensively field-tested. Stand-alone or hybrid processes using this improved membrane can prove useful in treating gas to meet pipeline specifications and in de-bottlenecking existing solvent absorption plants.

An H_2S -selective membrane has also been developed and tested, allowing the same hybrid approach to be applied to sour gas. This membrane can be used for conditioning H_2S rich fuel gas, thereby reducing engine maintenance needs.

INTRODUCTION

The first CO_2 removal membrane systems were installed in the early 1980s. Since then, the use of membranes in natural gas processing has been predominantly for CO_2 removal. However, new approaches in membrane manufacture have changed that picture in recent years. One breakthrough is the commercialization of processes using composite membranes. Each layer of the composite structure can be individually tailored to achieve optimal properties.

The use of these new membranes and processes has addressed a key concern of the industry—membrane stability—and has reduced the need for significant pretreatment to protect membranes from plugging, fouling, and failing chemically or mechanically.

Membrane Technology and Research, Inc. and ABB Lummus Global have signed an exclusive agreement for the use of these membranes in natural gas processing.

MEMBRANE BACKGROUND

Traditional membranes used for CO_2 removal are made from a single polymer, such as cellulose acetate, cellulose triacetate or polyimide. These membranes, known as asymmetric membranes, are cast in such a way as to form a thin, dense skin on a sponge-like porous substructure. The underlying porous layer provides mechanical strength; the thin skin layer is responsible for the separation properties. Polymers that exhibit good separation performance may not be ideally suited for providing mechanical support and long term chemical stability. Therefore, a compromise has to be made, and usually results in a membrane that is neither a very good separation membrane nor sufficiently robust.

Better membranes can be made if the performance and strength properties are uncoupled. MTR has developed composite membranes with this capability and specifically geared to the natural gas market. The cross section of one of these membranes is shown in Figure 1. The membrane consists of three layers: a nonwoven fabric that serves as the membrane substrate (the support web); a tough, durable, solvent-resistant microporous layer that provides mechanical support without mass transfer resistance; and a nonporous, defect-free selective layer that performs the separation.

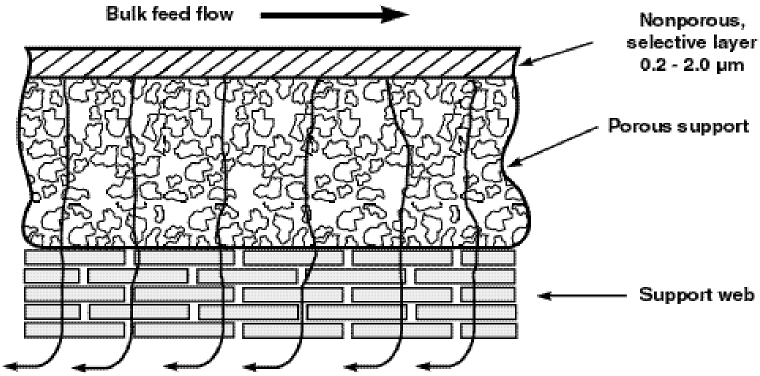

Figure 1. Cross-section of an MTR composite membrane

This configuration allows each of the layers to be independently chosen to optimize their function: the selective layer for high flux and selectivity, and the support layers for mechanical and chemical stability without influencing the separation. Specific selective layers may be chosen for specific separations, opening up exciting new applications, such as separation of heavy hydrocarbons from light hydrocarbons and nitrogen, separation of CO_2 and H_2S from methane, and dehydration.

COMMON GAS CONTAMINANTS: Effects on new and traditional membranes

Table 1 shows the effect of various commonly occurring contaminants on the membranes discussed in this paper. The last column shows the effect of these contaminants on traditional glassy membranes used in the gas patch. As Table 1 indicates, the new membranes show enhanced stability against common contaminants, and mitigate the need for extensive pretreatment trains. When traditional membranes for CO_2 removal are used, heavy components, such as aromatics, BTEX, and heavy aliphatic hydrocarbons do not permeate the membrane. As the CO_2 is removed, the concentration of these components can build up in flowing along the feed channel. If the concentration reaches a level such that the phase envelope is crossed, hydrocarbons can condense out of the gas on the surface of the membrane. Since these organic liquids are often solvents for the membrane materials, such condensation can be potentially devastating, by literally dissolving the membranes. Significant pretreatment of the feed gas is usually required to prevent hydrocarbon condensation. The simplest treatment is to heat the gas above the highest expected dewpoint, but in many cases adsorption beds or refrigeration are required upstream to lower the hydrocarbon content.

The composite membranes developed by MTR use materials that fare much better when exposed to hydrocarbons. The new custom membranes for NGL recovery, nitrogen separation and H_2S removal are essentially unaffected by aromatics and other condensable hydrocarbons, even under saturation conditions. Further, these components do not build up on the feed side; rather they permeate the membranes preferentially. As the high pressure feed gas passes across the membrane, these condensable components are the first to be stripped from the gas and are collected as a low pressure, vapor phase permeate stream. The result is that the dewpoint of the gas decreases, not increases, as the gas travels along the feed channel. Therefore any possibility of condensation on the membrane surface is avoided.

The new membrane developed by MTR for CO_2 removal behaves in the same manner as traditional membranes insofar as it selectively permeates CO_2 and rejects hydrocarbons. However, the chemistry of the membrane has been carefully designed so that aromatics and other hydrocarbons are not solvents for the membrane materials. Therefore, even if briefly exposed to liquid hydrocarbon condensates, the membranes are not permanently affected. After removal of the liquids, the membranes continue to function normally.

Further, the chemical structure of the new membrane materials, and their packaging configuration as spiral wound elements, allows them to be cleaned and reused. This results in lowered operating costs and reduced disruption to production.

<u>MEMBRANE PACKAGING</u>

MTR makes composite membranes in flat-sheet form and packages them in a spiral-wound module configuration, as shown in Figure 2. Spacers on the feed and permeate sides of the membrane create flow channels. The feed gas enters the module and flows between the membrane sheets. The faster permeating component permeate the membrane preferentially, and flow inward to a central collection pipe. Slower permeating components are rejected and exit as the high pressure residue stream.

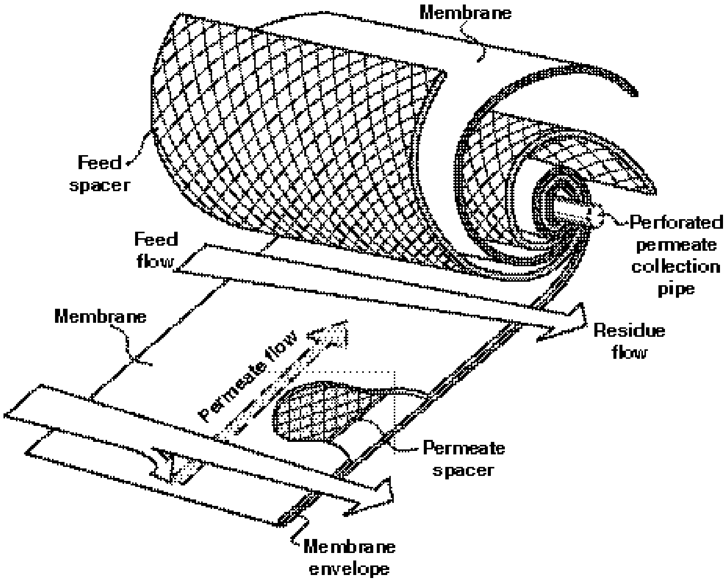

Figure 2. Schematic diagram showing components and gas flow patterns of a spiral-wound module

The spiral-wound modules are manifolded and placed in pressure vessels made from commercial steel pipe. The membrane elements are configured in series and parallel flow combinations to meet the requirements of the particular application. A picture of a typical skid-mounted membrane system showing two pressure tubes is shown in Figure 3.

Figure 3. A typical membrane skid, showing two steel pressure tubes hosuing the membrane modules.

HISTORY OF MEMBRANE APPLICATIONS

MTR has commercialized several applications of the hydrocarbon-selective membranes described above in the petrochemical industry. In particular, MTR has used the hydrocarbon-permeating/gas-rejecting properties to build systems for recovery of C_2, C_3, C_4 and C_6 components from nitrogen. Applications have been successful for flow rates ranging from 0.2 MMSCFD up to 90 MMSCFD, and pressures from 50 psia to 1,000 psia. The successful applications include hydrocarbon recovery from vent and purge streams, and fuel gas conditioning for large gas turbines. With over 80 references worldwide, and over 400 years of cumulative operating experience, the ability of the membranes to withstand a range of feed components and impurities has been well proven.

DESCRIPTION OF NEW APPLICATIONS AND PROCESSES

NITROGEN REMOVAL PROCESS

Nitrogen separation from natural gas has traditionally been performed using cryogenic processing. In the past decade, membrane and PSA processes have been introduced. Table 2 shows a general comparison of these technologies and their applicability ranges.

Table 2. A Comparison of Nitrogen/Methane Separation Processes

Process	Flow Range (MMSCFD)	N_2 Content (Mol%)	Complexity	Hydrocarbon Recovery	Development Stage
Cryogenic Processing	>15	> 15	Complex	Heavy hydrocarbon in product gas	Mature
PSA	2 -15	4 - 25	Simple. Batch operation requires bed switching	Heavy hydrocarbons in tail gas	Early Commercia-lization
Membrane	0.5-25	4-25	Simple continuous operation	Heavy hydrocarbon in product gas	Early Commercia-lization

When a feed gas containing nitrogen is introduced to a NitroSep membrane stage, a nitrogen rich stream will be rejected from the membrane and a hydrocarbon rich stream will pass through the membrane to the permeate outlet. By connecting two or more membrane stages, a well-defined separation can be achieved without resorting to cryogenic temperatures or collecting liquid hydrocarbons. By utilizing the nitrogen-rich stream as fuel, maximum overall efficiency can be realized. The NitroSep system can be designed to recover condensate for resale if the incoming gas is saturated with heavy hydrocarbons.

NitroSep systems can be as simple as a single stage unit, to treat streams that are only slightly out of specification in nitrogen, or can have two or more steps or stages to achieve high hydrocarbon recovery and nitrogen levels less than 2%. The flexibility of the membrane system allows for significant variations in inlet gas compositions and flow rate while achieving desired product specification.

Figure 4 shows a typical flow scheme of a NitroSep process. The low pressure inlet gas is compressed and introduced into the membrane inserts. Pipeline quality gas is generated in the first step, which includes recovery of most of the heavy hydrocarbons. The second step allows increased recovery of methane, which is recycled to the inlet compressor for further processing. The composition of the nitrogen-rich reject gas from the second step is adjusted by that step to be usable as compressor fuel. The membrane system is delivered in a single compact skid, which can be placed directly on gravel. To treat raw gas of high nitrogen content, additional membrane stages may be added to treat the first stage permeate.

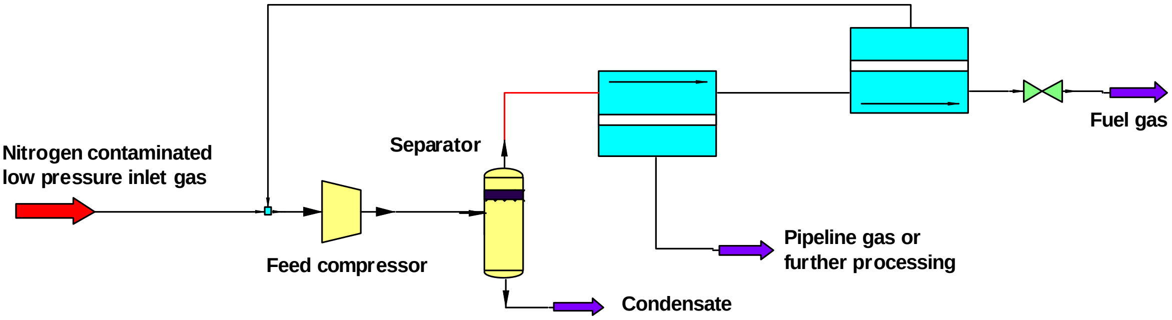

Figure 4. Flow scheme of a typical NitroSep© process for nitrogen removal from natural gas.

The membrane unit is simple to operate and control. The system can reach steady state performance within minutes of startup, and can be fully automated and remotely monitored.

The economics of the NitroSep process are affected by the nitrogen content in the feed gas, the value of the product gas, and the maximum allowable nitrogen content in the product gas. For upto about 30 mol-% N2 in the feed the membrane process can provide a solution that is economically very attractive. The membrane process is especially suited to process smaller flow rates of gas allowing smaller wells to be produced economically.

The membrane process is flexible and can be designed to maximize hydrocarbon utilization and revenues. The BTU value of the nitrogen reject stream can be tailored to match the fuel specification of compression sets used in the NitroSep process, or any can be used to produce electric power in a Gen-set for electrically driven compressors. In addition, virtually all ethane and heavier components are recovered in the product gas sent to the pipeline. This maximizes the BTU value sent to product thereby increasing the total generated revenues. The overall membrane process can be designed to not only recover pipeline spec natural gas, but also NGL as a separate product. In addition, if required the overall process including a Gen Set can provide electrical power for the sale to the grid.

NitroSep can be used as a stand-alone operation to process gas from as low as 0.5 MMscfd to 20-30 MMscfd or higher. The membranes operate at near ambient temperatures, and in most cases no separate dehydration or hydrate control is required. There is no accumulated liquid in the system, so no risk of pool fires or need to dispose of or store liquids. If desired, however, the system design does offer the flexibility to recover hydrocarbon liquids to increase total revenues.

Figure 5 shows a picture of a membrane skid installed In Omaha processing natural gas containing about 6.5 mol-% N2 down to less then 2.5 mol-%. The system has been operational since November 2002 and provided constant performance for the client. The system has been designed to allow upto 50% turndown "on the fly", to accommodate the changing needs of the customer in the plant.

Figure 5. System Photograph of Unit installed in Omaha, Nebraska, reducing 6.5 mol-% N2 in Natural gas to 2.5 mol-%.

Figure 6 shows a picture of a skid-mounted unit under construction for NTE exploration. The unit will process 1 MMSCFD of gas containing 24% nitrogen and generate product gas containing 4% nitrogen.

Figure 6. A skid-mounted mounted nitrogen-removal unit. The unit will process 1 MMSCFD of gas.

NGL SEPARATION PROCESS

The hydrocarbon-selective membranes used in the nitrogen separation process described above are also very suitable for removing condensable hydrocarbons to lower the dewpoint of the gas, or to control the Btu value of engine or turbine fuel streams.

MTR has three references in this area, including one in Brazil for conditioning turbine fuel gas, and others in offshore locations for conditioning gas engine fuel.

A schematic flow diagram for this application as applied to conditioning gas for gas engines is shown in Figure 7. A low-pressure natural gas stream is compressed to a high pressure in a pipeline compressor. The compressor is driven by a direct-drive gas engine, which is fueled by raw compressed natural gas. A small side stream is diverted from the raw compressed gas pipeline and enters the membrane system. The membrane separation step removes the heavy hydrocarbons, as well as other contaminants, such as CO_2, H_2S and water vapor, to produce a lighter, sweeter, drier conditioned residue stream, and a heavy-hydrocarbon-enriched permeate stream, which is recycled to the compressor inlet. The conditioned residue stream has a lower Btu value and a higher methane number, and is fed to the engine fuel intake. The membrane system can be designed to meet methane numbers specified by engine manufacturers. The performance results for this system are discussed below.

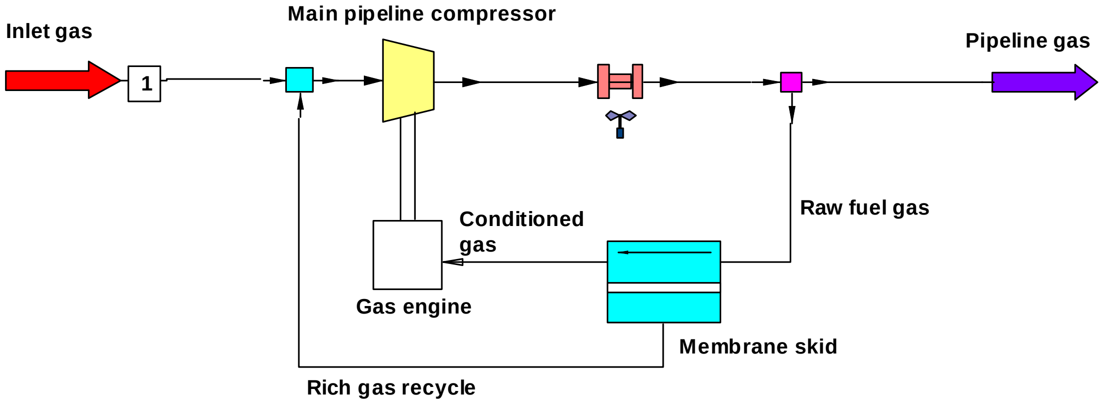

Figure 7. Schematic process flow diagram for a membrane fuel gas conditioner for a gas engine application.

The composition and conditions of the main streams in the process shown in Figure 7 are given in Table 3.

Table 3. Feed and Conditioned Fuel Gas Compositions and Important Process Variables.

Process Conditions	Membrane Feed	Conditioned Fuel Gas
Temp (oC)	35	10.5
Pressure (bar gauge)	65	65.0
Total mass flow (lbmol/h)	110.1	58.0
Total volume flow (MMscfd)	0.95	0.5
Component mol%		
Carbon dioxide	1.3	0.6
Methane	72.8	81.2
Ethane	9.6	9.0
Propane	9.9	7.1
i-Butane	2.4	0.8
n-Butane	2.5	0.9
n-Pentane	1.3	0.4
Water	0.11	0.00
Hydrocarbon dew point (^{o}C)	35	3.5

The data in Table 3 show that the membrane process selectively removes the C_{3+} hydrocarbon components from the feed gas. The conditioned fuel gas meets both the Btu value and methane number specifications for the gas engine. The dew point of the gas is reduced from 35^{o}C to 3.5^{o}C in the process.

The system is compact (6 ft x 6ft x 6 ft), has no utility requirements, no moving parts, and requires no operator attention.

The same process applied to conditioning gas for turbine gensets in a Brazilian power plant is shown in Figure 8. The membrane unit produces 90 MMSCFD of conditioned natural gas at 900 psia for use in two Siemens gas turbines

Figure 8. Photograph of a membrane unit for conditioning turbine fuel by removing hydrocarbons.

CO_2 REMOVAL PROCESS

The removal of CO_2 has been the predominant traditional application of membranes in the natural gas industry. Numerous small plants and several larger plants processing up to 500 MMSCFD of gas or more have been installed using cellulose acetate, cellulose triacetate or polyimide membranes. These polymer materials show good separation performance but are known to be susceptible to damage due to exposure to aromatics, other organics liquids or water, any of which can cause irreversible damage to the membranes. To mitigate the risk of damage, membrane processes utilize significant pretreatment steps to remove offending components down to acceptable levels. This increases capital and operating costs, and adds complexity to an otherwise simple process. Additionally, any upsets in the pretreatment train may still expose the membranes to harmful contaminants, resulting in the need to replace the membrane inserts.

To address this issue, MTR has focused on developing more intrinsically robust membranes. These membranes can operate safely with minimal pretreatment of the feed gas, and are more forgiving of accidental exposure to high levels of contaminants. The membranes are based on polymer chemistry similar to that of Teflon®, the well known non-stick material. These polymers do not dissolve or disintegrate in aromatics like other conventional polymers, and retain performance even after a limited accidental exposure to such components.

Table 1 above shows the various common contaminants of natural gas and how they can affect membrane performance. The Z-Top membrane shows superior chemical stability for CO_2 removal applications.

An additional benefit is that the Z-Top membranes exhibit gas fluxes an order of magnitude higher than membranes made from traditional polymers, so that smaller membrane area is required to perform a given separation, resulting in a smaller skid size, and in some cases lowering costs.

The membrane process can be used as a stand-alone or a hybrid process. In a typical hybrid flow arrangement, shown in Figure 9, the membrane separation step is followed by an amine absorption step. This process configuration is useful for bulk CO_2 separation and for debottlenecking existing CO_2 removal plants. The membrane system is used to remove a significant portion of the acid gases (as much as half or more) from the gas entering the amine contactor. This allows additional flow to enter the amine plant, while significantly reducing the load on the amine regeneration section.

A combination of membranes described in this paper can be used to effectively reduce CO2 and conditioned gas for the amine system.

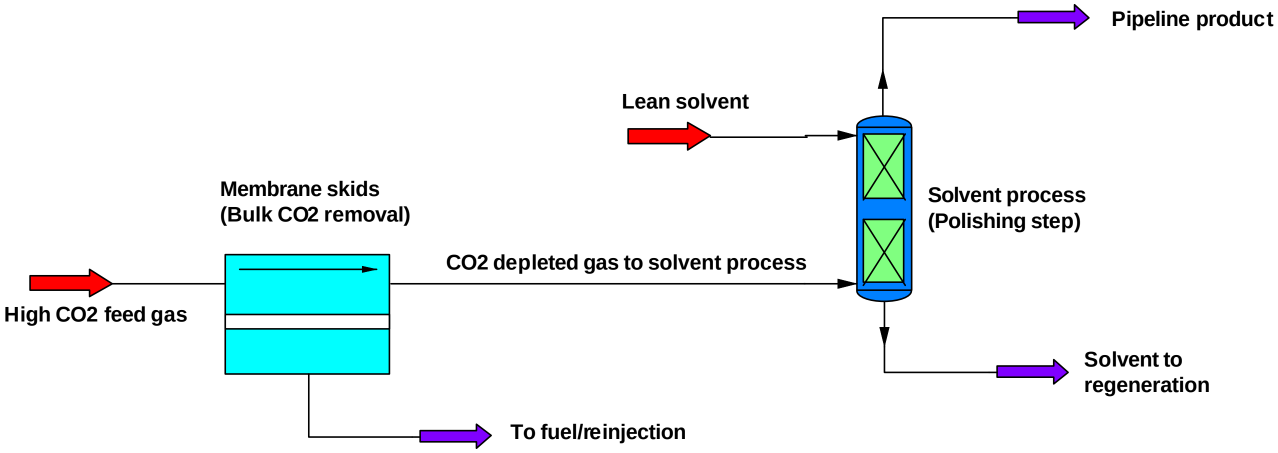

Figure 9. A hybrid process for CO_2 removal from natural gas, using a membrane separation step followed by a solvent absorption step. The membrane step can cut the acid gas content of the feed to the amine plant by half.

H_2S REMOVAL PROCESS

MTR has also developed a membrane process for H_2S removal from natural gas. The applications of this membrane process include bulk separation of H_2S from sour natural gas, and removal of H_2S from fuel gas streams used in gas engines and turbines.

The chemistry of the membrane results in preferential permeation of H_2S and other sulfur-bearing components over hydrocarbons. A simple process scheme illustrating how this membrane can be applied for fuel gas conditioning is shown in Figure 10.

A slip stream of raw fuel gas is taken from the main gas line, cooled as required and fed to the inlet of the membrane separation unit. A separator removes condensed heavy hydrocarbons from the membrane process loop. The membrane permeate, enriched in acid gas, is returned to the main gas line. The residue stream is sufficiently reduced in acid gas content, and heavy hydrocarbons, to meet fuel specifications for a gas engine or turbine.

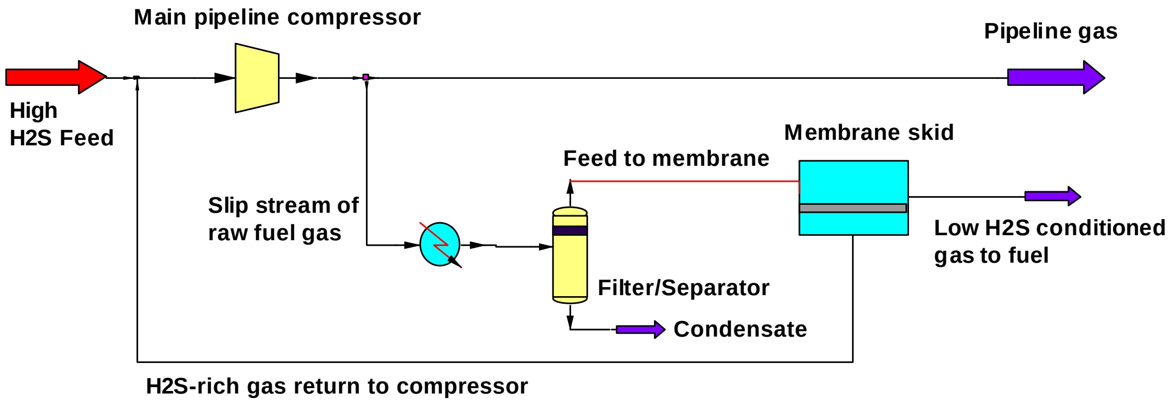

Figure 10. Typical process scheme for H_2S removal from fuel gas to condition engine and turbine fuel gas.

Table 4 shows the mass balance for the membrane separation step.

Table 4. Membrane Separation Performance for Removal of H_2S from Fuel Gas

Stream Name	Feed to Membrane System	Conditioned Gas to Fuel	Return Gas to Compressor
Temperature (^oF)	90	35	62
Pressure (psia)	1015	1013	45
Total Flow Rate (MMscfd)	1.72	0.76	0.96
Component mole %			
Helium-4	0.07	0.11	0.04
Nitrogen	0.40	0.76	0.12
Carbon Dioxide	1.91	0.19	3.25
Hydrogen Sulfide	**0.34**	**0.004**	**0.60**
Methane	85.92	95.24	78.62
Ethane	6.92	2.88	10.09
Propane	2.72	0.62	4.36
I-Butane	0.37	0.05	0.62
N-Butane	0.67	0.09	1.13
I-Pentane	0.18	0.02	0.31
N-Pentane	0.19	0.02	0.32
N-Hexane	0.16	0.01	0.28
N-Heptane	0.10	0.01	0.17
N-Octane	0.04	0.00	0.07
Water	0.01	0.00	0.02

Table 4 shows that the membrane unit can reduce the H_2S content in the fuel from about 3,400 ppm to about 40 ppm. In this way, engine or turbine components are protected, corrosion is reduced, and a significant reduction in maintenance needs can be achieved. Use of the process also minimizes the need to buy higher priced sweet gas, which can result in significant cost savings. As an on-site treatment, membrane separation is preferred over liquid or solid scavengers because of the very low operating cost of the system.

Thus, the membrane system combines low capital and operating costs with a good technical solution to a processing problem for which conventional technologies are not attractive.

As with the CO_2 removal process described previously, H_2S removal may be carried out in a stand-alone operation, as shown in Figure 10, or in a hybrid arrangement.

In a hybrid process, the membrane separation step is best suited for a first bulk H_2S separation, and can be followed by conventional amine treating or other H_2S removal technology, in a manner similar to that shown in Figure 9 for CO_2 removal.

Such a configuration can debottleneck existing gas processing facilities, especially when the H_2S-rich gas can be re-injected. The membrane step can reduce the load on the regeneration columns and Claus plants downstream.

The availability of the membrane bulk removal step also allows producers the flexibility to improve the quality of acid gas that is to be sent by pipeline to remote treatment facilities.

SUMMARY

The use of membranes in the natural gas industry is expanding beyond CO_2 removal. Composite membranes that provide custom-tailored properties are being developed and commercialized. These membranes offer improved resistance to aromatics and other contaminants, good separation performance, and competitive capital and operating costs. The availability of the new membranes has opened doors into a range of new applications, including nitrogen separation, heavy ends removal for gas conditioning and dewpoint control, and acid gas separation.

The NitroSep process offers opportunities to treat gas flows down to as low as 0.5 MMscfd to meet pipeline nitrogen specification and achieve good hydrocarbon recovery.

The Z-Top membrane process can cut the CO_2 concentration of a raw gas stream in half, and provides a convenient way to unload downstream amine systems. The H_2S separation can be applied for bulk sweetening prior to conventional amine treating, or to reduce the H_2S content of engine or turbine fuel gases.

All of these membrane processes can operate safely, and meet separation performance targets, with much reduced pretreatment needs compared with traditional membranes.

Membrane manufactures continue to develop new membranes and processes in response to important user concerns about membrane robustness and reliability. In light of this, membranes are expected to capture a larger market share in the future.

Table 2. Effect of contaminants on new and traditional membranes for natural gas treatment

		NitroSep Membrane	Z-Top membrane	H_2S Membrane	Traditional Glassy Membranes
Contaminant	**Occurrence**	**Comments**	**Comments**	**Comments**	**Comments**
Mercury Elemental and/or organic?	Uncommon	No effect	No chemical interaction. No effect expected	No effect	No Effect
Inorganic salt	Uncommon	Particulate filter should remove all salts particles > 0.3 microns. Chemical reactions not expected	Chemical reactions not expected	Chemical reactions not expected	Filter Separator removes all salt particles > 0.3 microns. Hollow fibers can be fouled leading to higher pressure drops
Asphaltenes	Rare	No chemical interaction. May cause flux decline over time	May cause flux decline over time if deposited on membrane towards the residue end	No chemical interaction. May cause flux decline over time	Causes flux decline over time. In some cases severe flux declines observed
Paraffinic waxes	Rare	Heavy hydrocarbon permeate the membrane. Waxes may deposit on membrane over longer period but can be cleaned with a liquid wash	No chemical interaction expected. May cause flux decline over time if deposited on membrane. Membrane can be washed with hydrocarbon solvent to remove	Heavy hydrocarbons permeate the membrane. Waxes may deposit on membrane over long periods but can be cleaned with a liquid wash	Will deposit on membrane surface and lower fluxes. Cannot be washed away with liquid solvents
Water	Common	No effect	No effect. Permeates the membrane resulting in gas dehydration	No effect. Permeates the membrane. Effective dehydration membrane	Significant flux decline in some membranes. No effect on some other glassy membranes
Elemental sulfur	Rare	No effect. May plug flow channels and increase pressure drop but would be stopped by filter separator	No chemical reaction expected. But if coated on membrane flux decline could occur	No effect. May plug flow channels and increase pressure drop but would be stopped with filter separator	Unknown
Mercaptans	Common	Permeate the membrane. No effect expected	Smaller mercaptans expected to behave like H_2S. Larger mercaptans will be rejected to product stream	Permeate the membrane. No effect expected	Unknown
Oxygen	Uncommon	Permeates the membrane. No effect	No effect	No effect	Unknown
Aromatics	Common	Permeate the membrane very quickly. Removed from the feed within the first few membrane cartridges. Minor membrane swelling expected but no other effect on performance	Lab data suggests membrane swells to some extent, but is resistant to BTEX (and other hydrocarbons) Hydrocarbons will be rejected to residue stream and build up from feed to residue end of modules	Permeate the membrane very quickly. Removed from the feed within the first few membrane cartridges. Minor membrane swelling expected but no other effect on performance	Aromatics are solvents for many conventional glassy membranes. Accidental exposure to aromatics can result in severe irreversible damage requiring change out
Ethylene glycol	Common	No effect	May cause flux decline over time if deposited on membrane	No effect. Over time may result in flux decline in the first elements exposed to the feed gas. Can be washed from the membrane surface	May cause flux decline over time if deposited on membrane
BTEX	Common	Permeates the membrane. No permanent effect except swelling of the membrane in the lead elements	No interaction of liquid BTEX with membrane. Once liquid BTEX is removed, membrane regains original performance	Permeates the membrane and is removed from the feed. No permanent effect except swelling expected.	BTEX are Solvents for the membrane. Exposure will result in destruction of membrane.
Methanol	Common	No effect	No effect	No effect	Unknown
TEG	Common	TEG aerosols will be removed in the filter separator. No chemical interaction with membrane	TEG aerosols will be removed in the filter separator. No chemical interaction with membrane	TEG aerosols will be removed in the filter separator. No chemical interaction with membrane	If gas heated, TEG may break down and products will deposit on membrane
Amine	Common	Amine aerosols will be removed in the filter separator. No chemical interaction with membrane	Amine aerosols will be removed in the filter separator. No chemical interaction with membrane. May accumulate on surface over time, can be washed away	Amine aerosols will be removed in the filter separator. No chemical interaction with membrane	If gas heated, amines may break down to products that are harmful to membrane
Wellhead treatment chemicals	Uncommon	No effect of surfactants etc on membrane	Filter separator removes any aerosols. No interaction with chemicals expected	No effect of surfactants etc on membrane	Unknown