COST EFFECTIVE NATURAL GAS CONDITIONING: TWELVE YEARS EXPERIENCE OF MEMBRANE SYSTEM OPERATION

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ABSTRACT

Quicksilver Resources owns and operates the Hayes 29 Gas Plant near Gaylord Michigan. A paper was published on the decision to install a membrane-based CO_2 removal system at the facility in the April 1995 issue of Hydrocarbon Processing. In the original paper, the justification for choosing a membrane system over an amine/glycol system was discussed and economic data presented. At that time, the membrane system had been in operation for 15 months, allowing comparison of projected cost to actual cost.

This paper reviews the same system's performance over the twelve-year period since commissioning. Actual performance data and cost of operation are presented. Based on operating cost (including product loss and fuel usage), system flexibility, system reliability and system performance, the original economic evaluation is shown to have been conservative. In particular, membrane life has far exceeded expectation and strongly contributed to improved economic performance. Operating costs are shown to be $500,000 lower per year than estimated for an amine system followed by a glycol dehydrator.

Also presented in the paper is a report on the installation of new, improved membrane elements that have increased hydrocarbon recovery and further reduced operating costs during 2006.

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COMPANY INTRODUCTION

Quicksilver Resources Inc. (Quicksilver) formerly Mercury Exploration Company, was founded in 1965 and is headquartered in Fort Worth, Texas. It is an independent oil and gas company engaged in the development and production of natural gas, natural gas liquids (NGL) and crude oil, which it attains through a combination of developmental drilling and property acquisitions. The Company's efforts are principally focused on unconventional reservoirs, such as hydrocarbons found in fractured shales, coal seams and tight sands. Quicksilver's operations are concentrated in the Michigan, Western Canada and Fort Worth Basins. As of December 31, 2005, it had estimated proven reserves of 1.1 trillion of cubic feet of natural gas equivalent, of which approximately 92% were natural gas. The Company's asset base is geographically diverse, with approximately 52% of reserves in Michigan, 27% in Canada and 16% in Texas. At year-end 2005, the Company had average daily production of 140.9 million cubic feet of natural gas equivalent per day.

In the Michigan Antrim Shale, Quicksilver drilled or participated in 67 wells in 2005. Of its Antrim wells drilled in 2005, the Company reentered 10 vertical wells and drilled a horizontal leg from each existing well. As of December 31, 2005, Quicksilver's interests in the Antrim Shale had net production of 57.6 million standard cubic feet *equivalent* per day (MMCFED) and proved reserves of 504 billion cubic feet equivalent (BCFE). Net production for its Michigan non-Antrim properties was 20.9 MMCFED and total proved reserves were 78 BCFE.

The subject of this paper is the Wilderness (Hayes 29) gas processing facility, one of two gas processing facilities owned and operated by Quicksilver in northern Michigan. Located 15 miles SW of Gaylord, Michigan, the plant removes CO_2 and water from gas gathered from both Antrim and non-Antrim properties. Gas arrives at the facility via high-pressure discharge line from satellite compressor stations and via low pressure gathering closer to the plant. Locally gathered gas is compressed to approximately 1000 psig. The combined gas streams are fed to a Separex™ Membrane System for removal of CO_2 to less than two mole percent and removal of water to less than seven pounds per million standard cubic feet. The treated gas goes into the CMS or DTE Energy pipelines for distribution to southern Michigan areas.

SYSTEM CONFIGURATION

Plant 1 of the Wilderness project was started up in December 1993 by Mercury Exploration Company. Initial gas inlet was less than 15 million standard cubic feet per day (MMSCFD) at 925 psig. The feed gas contained less than the design 11% CO_2. Product gas with <2% CO_2 was obtained from one 30-tube primary membrane skid and one 6-tube secondary membrane skid.

Two additional 15 MMSCFD membrane trains were added at the same location as Plants 2 and 3 during July and August 1994. These plants saw the installation of the second and third 30-tube primary membrane skids along with one additional 10-tube second stage skid. Each plant has its own pretreatment section. The modular nature of the plant skids allowed phased investment while drilling increased the amount of gas available for treatment. This was one of the advantages of membrane technology over amine treating.

Total processing capacity today is 45 MMSCFD with inlet CO_2 concentration approaching 15 mole%, a 36% increase above the design value. Outlet specification remains <2% CO_2. A process flow sketch is shown in Figure 1.

Natural gas is delivered to the first membrane stage pretreatment section which provides key protection for the membrane elements. Accumulation of solids or liquids on the membrane surface can cause a decline in performance by damaging or blocking the membrane surface. Feed gas passes through a high-efficiency coalescing filter for removal of entrained contaminants such as sand, pipe scale, lubricating oil and water or hydrocarbon condensate. Filtered gas is then fed to an activated carbon guard bed to remove trace contaminants – particularly lube oils. Contaminant-free gas is then routed to a particle filter to remove any entrained dust from the guard bed. Filter gas is then fed to a preheater to warm the gas to the desired operating temperature. For the water-saturated feed gas, at least 15 degrees Fahrenheit (ºF) of super heat must be provided above the inlet water dew point. The primary membrane preheater is a direct-fired, glycol-water bath heater containing a U-tube downstream of the burner and a process gas heating coil. The preheater has a rated duty of 1.0 million British thermal units per hour (MMBTU/Hr).

After pretreatment, warm gas enters the two-stage membrane system. The first membrane stage consists of six banks (rows) of five membrane tubes. The arrangement of the banks is three tube banks in series with three tube banks. As the feed gas flows through the membrane tubes, the gas is separated into a CO_2-rich permeate stream at low pressure and a CO_2-depleted residue stream (or non-permeate stream) at high pressure. The residue gas contains <2% CO_2 and is sent to sales gas metering. Pressure drop from feed to residue is less than 10 pound per square inch (psi). Overall pressure drop, including pretreatment, is 15-20 psi.

The CO_2-rich permeate gas is compressed and routed to the second stage pretreatment section to remove lubricating oil entrained from the permeate compressors. The secondary pretreatment equipment is identical to the primary pretreatment, but smaller in size. The secondary membrane preheater has a rated duty of 0.25 MMBTU/Hr. Residual gas from the second stage membranes is recycled to the first membrane stage for hydrocarbon recovery. Permeate from the second stage is sent to the vent.

The use of piping headers to distribute the gas between the three membrane skids and between the six available permeate compressors has yielded maximum flexibility in the operation of the plant. Downtime for the entire plant is very rare, given the arrangement of the equipment. It should be noted that even if all the permeate compression were to be off line, the plant could still process gas and meet pipeline specifications for CO_2 and water. In single-stage mode, hydrocarbon recovery is reduced, but on-specification product gas continues without interruption.

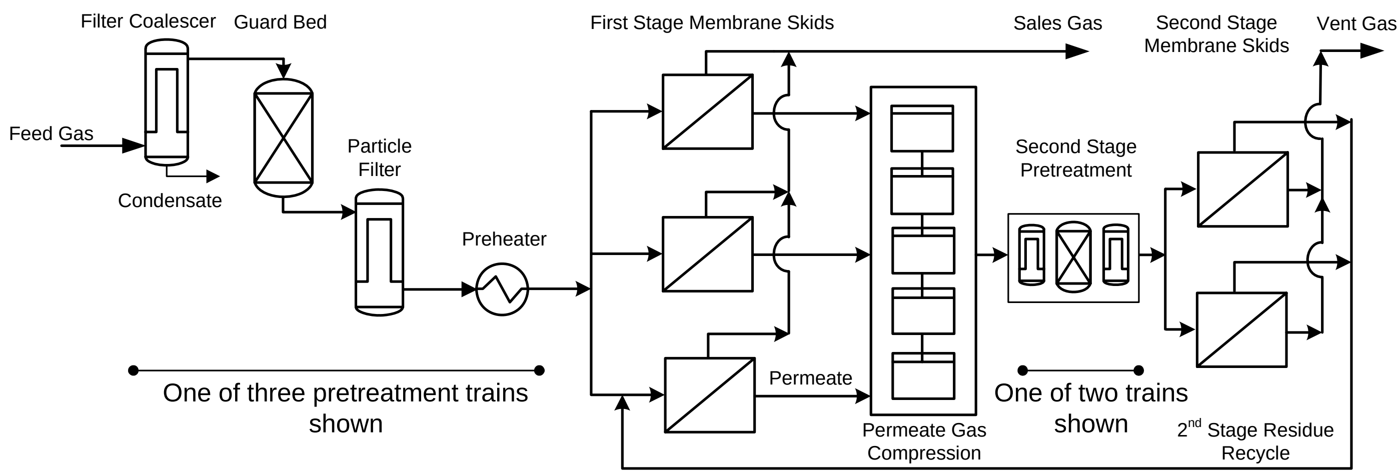

Figure 1 – System Configuration

SYSTEM PERFORMANCE

Information is available on system operating performance, element replacement rates, downtime and overall costs. Operating data was taken from the system logs, which were complied into a Microsoft Excel spreadsheet from the computer used to monitor plant operation. The computer records begin in January 1995. Most of the data shown here uses monthly average values to demonstrate trends in the operation of the plant.

System Operation

The facility is staffed by rotating three full time employees that spend approximately 8 hours a day, seven days a week, monitoring and maintaining the entire facility, including the local feed gas booster compressors and other production equipment. Operator time at the facility works out to less than 60 hours per week. Operators are on call for compressor outages.

Battery limit flow rates are shown in Figure 2. After completion of Plant 2 in July 1994, the system feed rate rose above 30 MMSCFD and climbed steadily with the addition of Plant 3 in August 1994, peaking at the rated capacity of 45 MMSCFD. The sales gas rate parallels the feed gas rate, rising from 26 MMSCFD and peaking at 39 MMSCFD. There has been <u>no</u> outage for the entire facility during the 12 years of operation from 1994 to now. In fact, two Plants (out of the three trains available) have ever been off-line at the same time over that span of years.

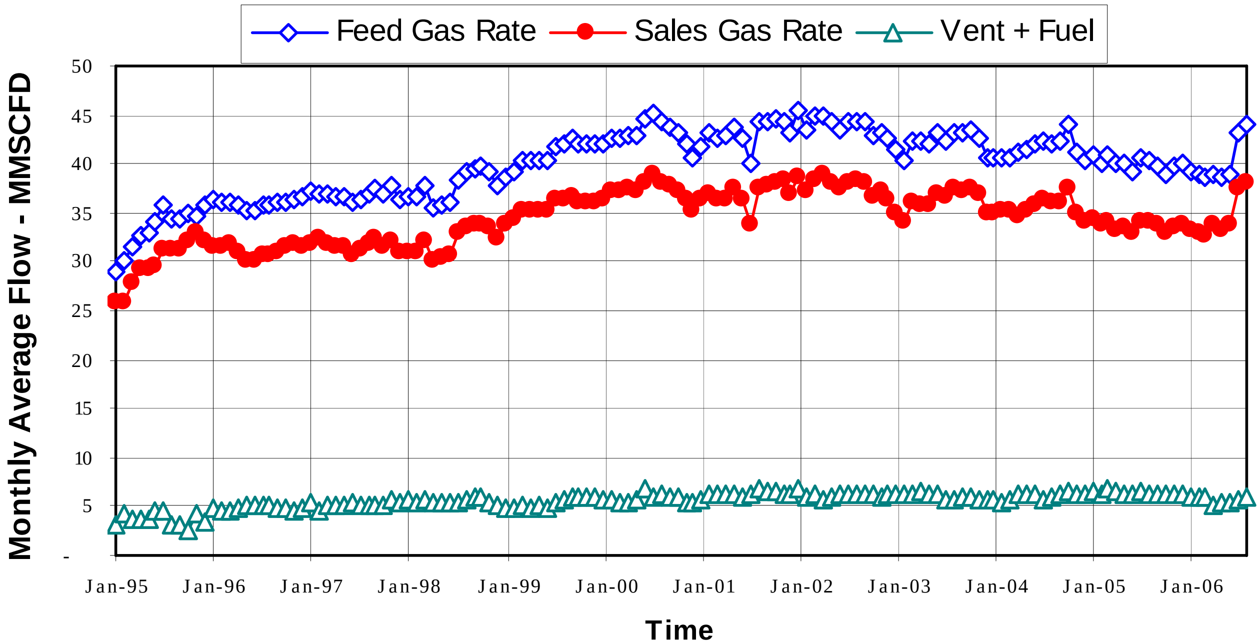

Figure 2 – Battery Limit Flow Rates

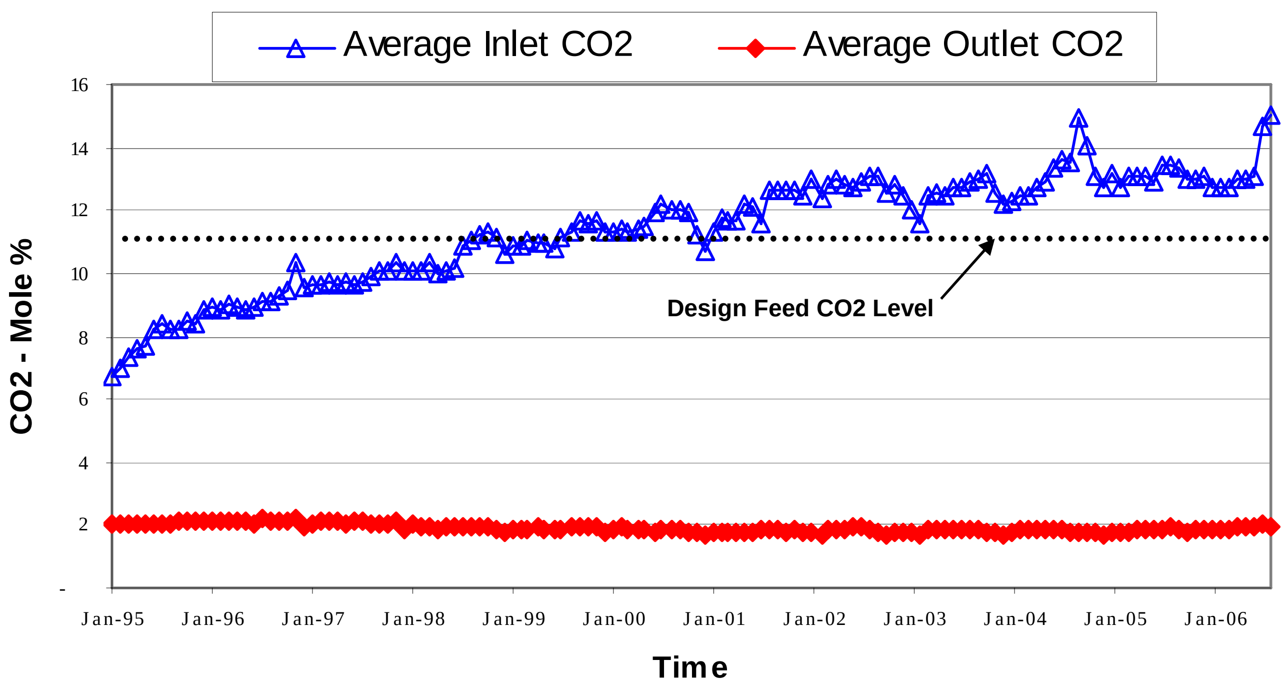

Figure 3 – CO_2 Levels

CO_2 Performance

The system maintained its capacity despite a steady rise in the inlet CO_2 content. Figure 3 shows the average inlet and outlet CO_2 content. In the early years, feed gas was below the design level of 11% CO_2. CO_2 now exceeds that value, but the plant is still able to operate on specification at capacity feed flow rate.

There are two principle ways to accommodate higher CO_2 levels in the feed gas to a two-stage membrane plant. The first would be to increase membrane area in both stages. This can be easily done if there is spare capacity to load additional elements in series within the membrane tubes. With more membrane area on line, more CO_2 can be removed based on equivalent inlet gas flow rates. This change would, however, increase permeate compression requirements.

The second method to accommodate higher CO_2 would be to increase the feed gas temperature to the primary stage. Membranes permeate more CO_2 at higher inlet temperatures based on equivalent inlet gas flow rates. Increasing feed temperature would increase permeate compression requirements and increase methane loss to the vent. Membrane selectivity is reduced when operating at higher inlet temperatures.

The Wilderness plant has not had to add membrane area or increase feed gas temperature to handle the additional CO_2 in the feed gas. They have achieved higher capacity due to the evolution of the Separex Membranes. Based on improvements to cellulose acetate membrane technology and membrane construction, the capacity of the elements has improved, allowing for lower temperature operation without increasing membrane area. Lowering the feed gas temperature improves membrane selectivity, allowing exiting permeate compressors to maintain high recovery despite the increase in feed gas CO_2 content. A specific example of this is presented in Figure 4.

Hydrocarbon Losses

In early 2006 the plant was operating a little below rated capacity but average CO_2 levels were at 13% and showing signs of going up even further. Methane loss to the vent was holding steady in the range of 2-2.5% of the feed gas methane (97.5 – 98% hydrocarbon recovery). Quicksilver decided to change out all the elements in the primary stage of the Plant 1 membrane skids. When the change was made in April of 2006, the feed gas temperature was also lowered to all membrane skids to improve hydrocarbon recovery. The result was a reduction in vent losses to less than 1%. Additionally, fuel use went down with the reduction in preheater duty and easing of permeate compressor loading. Since August of 2006, production has climbed to the rated capacity of 45 MMSCFD. Fuel gas usage and vent losses remain low.

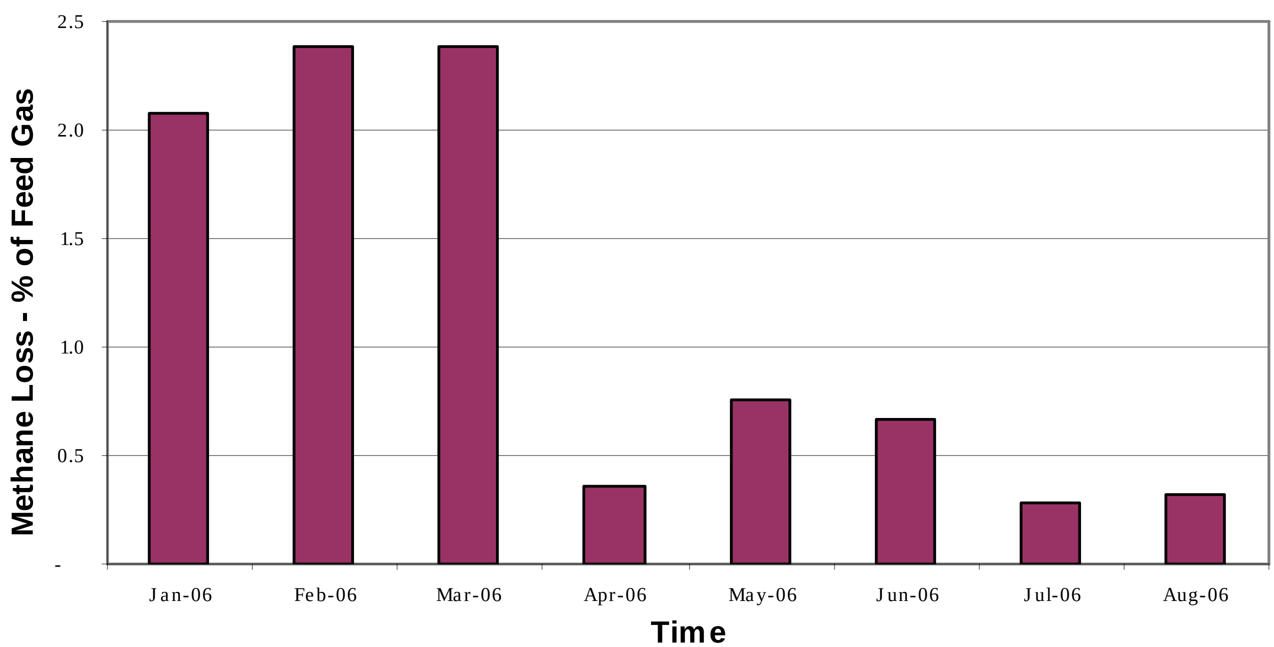

Figure 4 – Methane Losses as a Percent of Feed Gas

Element Replacement Rates

Figure 5 shows the percentage of elements replaced during 12 years of operation. The initial 100% loading of elements are shown for Plants 1, 2 and 3. Other than those initial fills, the plant has never replaced more than 33% of the membrane elements at any one time, 33% representing a full load for any one of the three plants. Overall, the facility has replaced 110% of the initial fill of elements. Element life has far exceeded the original estimate of four years. Longer element life translates into lower annual operating cost. Annual costs for element replacement have been less than one third the expected value used during the economic evaluation to justify the plant.

Long element life is mostly attributed to two factors. First, the gas feeding this plant is very lean, meaning there are very few heavy hydrocarbons that could contaminate the membrane elements. Heavy hydrocarbon components, when condensed, coat the membrane surface and prevent permeation. Secondly, the operators at the Hayes 29 facility are ever vigilant in maintaining the pretreatment equipment. They keep detailed records and look for the slightest signs that the carbon guard beds may be saturated. Spending a little more time and money on quality pretreatment maintenance has paid off in lower than expected membrane replacement cost.

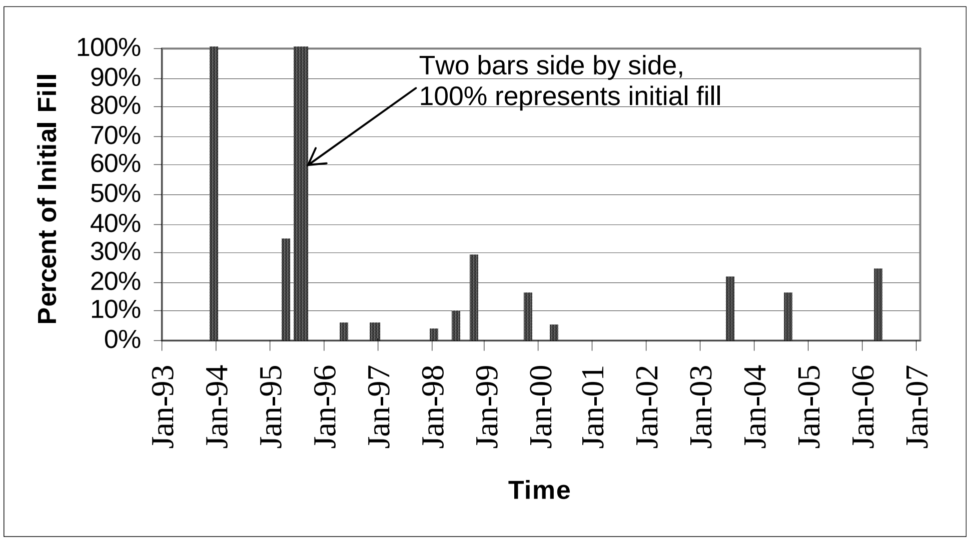

Figure 5 – Element Replacement

Downtime

The membrane system has been extremely robust. Operating logs indicate the main reason for any reduction in feed gas rates has been loss of feed gas compression. As noted above, there has been no outage for the entire facility (or even two of the 3 trains) since startup. That calculates to a downtime of 0.00% for the facility.

Smaller reductions in gas flow were related to pretreatment maintenance and membrane maintenance. Replacement of pretreatment consumables typically requires 3-4 hours and occurs 1-2 times per year for each pretreatment train. Only primary pretreatment maintenance results in a reduction of feed gas to the facility. Based on the numbers above, facility flow reduction of up to one-third (replacing pretreatment consumables in one of the three plants) only occurs for 24 hours in any year. That is a rate of 0.3% of the time at reduced rates due to pretreatment maintenance.

Due to the arrangement of the membrane elements in series, it is not typically required to replace all the elements after a certain amount of time. The first few elements see the most difficult service – higher partial pressures of CO_2 and more permeation than subsequent membrane elements. Replacement of the "lead" banks of elements is more frequent than replacement of the element banks in the "lag" position.

The duration of reduced feed gas flow due to membrane replacement depends upon the number of membrane tubes that are opened. When replacing membranes in an entire plant (30 primary tubes and 6-10 secondary tubes), two crews work for 30 hours to complete the job. This worst case scenario includes cleaning the tubes if any contaminants are found. Most element replacement takes less time because fewer elements are replaced. If all elements are replaced every 6 years, downtime for that plant would be 0.06%.

Overall Costs

Quicksilver calculates the cost of operating the Hayes 29 facility based on actual dollars allocated to plant operation divided by the raw gas entering the plant. In the April 1995 article it was estimated that processing costs would be 13 cents per 1000 standard cubic feet of gas (0.131 $/MCF). Since the initial operation was at lower than actual plant capacity, there was an estimated potential cost of 0.116 $/MCF due to longer element life.

In actuality, the average cost over the life of the plant has been 0.095 $/MCF. This represents a substantial savings when compared to the estimated cost of 0.130 $/MCF for amine treating followed by glycol dehydration. Comparing these two costs for a plant rated at 45 MMSCFD, operating costs for the membrane plant are over $500,000 less per year. Most of that savings come from prolonged membrane life and lower than expected fuel cost.

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