Reducing Carbon Emissions in Gas Plants

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Abstract

In recent years—decades even—a large push has been made to reduce the impact humans have on the environment. Carbon emissions contribute to global warming/ climate change. While there are a multitude of ways human activity impacts the environment, many of these cannot simply be suspended overnight without irreparable damage to the economic stability of society. A sizeable portion of carbon emissions released every year comes from our fuels. Carbon-based fossil fuels have been around for over a century and currently supply nearly 80 percent of the United States' energy.[1] Billions of dollars have been poured into research and development of alternative fuels, but it will take time and money to get these alternative fuels on par with current fuel demand. In the meantime, it is important to look at the feasibility of reducing the environmental impact of current energy sources, more specifically, reducing emissions during production, processing, and use of these fuels such as natural gas.

Natural gas processing plants (gas plants) are responsible for taking the gaseous mixture of hydrocarbons and other organic compounds from natural gas wells and removing contaminants—carbon dioxide, hydrogen sulfide, and others—from the natural gas, improving its quality. The processing of gas involves many processes, many of which use gas or power. Emissions from the use of the fuel / power are not the only issue, as some systems produce emissions, such carbon dioxide, methane, and other greenhouse gases to the atmosphere.

There are many methods that can be used to reduce carbon emissions in gas plants, some of which also include fuel gas savings. These methods typically fall into two main categories: direct and indirect. Some examples of direct methods include gas replacement such as glycol stripping gas with an inert gas and reducing venting required for compressor maintenance via recovery or flaring. Indirect methods examples include efficiency improvements such that less power is required to process the gas to the same specifications. Also, included in this category are heat recovery and integration possibilities that would also reduce fuel / power demand.

Study Objectives

The following study aims to identify potential ways to reduce the environmental impact of gas processing plants by reducing the amount of fuel gas consumed (local CO_2 emitted), CO_2 vented (local CO_2 emitted), electrical power required (remote CO_2 emitted), and natural gas vented (methane emitted). The study will present various options to reduce these emissions and compare these options with the current typical plant operations to evaluate the environmental and economic impact of each.

Introduction

Dating back to 1992, the U.S. Senate made its first commitment to combat climate change by approving the UN Framework Convention on Climate Change. Since then, especially in the last decade, a large push has been made to reduce the impact humans have on the environment. While there are a multitude of ways human activity impacts the environment, many of these cannot simply be suspended overnight without irreparable damage to the economic stability of society. A portion of carbon emissions released every year comes from our use of carbon-based fuels. Carbon-based fossil fuels have been around for over a century and currently supply nearly 80 percent of the United States' energy.[1] Billions of dollars have been poured into research and development of alternative fuels, but it will take time and money to get these alternative fuels on par with current fossil fuel demand. In the meantime, it is important to look at the feasibility of reducing the environmental impact of current energy sources, more specifically, reducing emissions during production, processing, and use of these fuels.

Natural gas processing plants are responsible for taking the gaseous mixture of hydrocarbons and other organic compounds produced from natural gas wells and removing contaminants such as carbon dioxide (CO_2), hydrogen sulfide (H_2S) , and other impurities, from the natural gas, improving its quality. This applies to more non-conventional sources of natural gas, too, such as landfills and bio-digesters. The processed gas is then sent out through a pipeline and eventually is used in generating electricity, petrochemical feedstock, as well as in residential and commercial heating. The processing of gas involves several processes, many of which use gas for fuel or power or in other ways. There are some systems in the plants in which carbon dioxide, methane (CH_4) , and other greenhouse gases are emitted to the atmosphere. By reducing these emissions, the environmental impact of these processes and facilities can be reduced.

There are many methods that can be used to reduce emissions in natural gas processing, many of which are listed in this study. These methods generally fall into two categories: direct—such as fuel gas savings and gas capture, and indirect—such as waste heat recovery and improved efficiency. Replacing fuel gas used in cases such as stripping gas, blanket gas, and purge gas could save on fuel gas consumption. A lot of waste heat is produced in the processing of natural gas, which instead can be strategically used to heat other parts of the process, and thereby reducing the gas required for heater fuel. Capturing and recycling gas that would otherwise be vented will reduce methane emissions. Similarly, capturing and sequestering vented carbon dioxide would reduce CO_2 emissions. Finally, improvements to processing efficiency will reduce fuel consumption and/ or electrical demand.

The different methods of emission reduction will be compared in terms of fuel gas savings (MMSCF/year) where applicable for economic justification. For economic comparisons, the natural gas price assumed is $3 /MMBtu and the price of NGLs is $50 /BBL. Comparison will also be made in terms of CO_2 equivalent (CO_2e) as defined in Table 1 of 40CFR98 and summarized below in equation 1. CO_2e will be reported in tonnes/year (metric ton/year). For this study no NO_2 is expected, so CO_2e will be based on CO_2 and CH_4 emissions for a gas plant operating 360 days/year.

$$CO_2e = CO_2 + CH_4 + NO_2$$

(Equation 1)

With the following factors applied

$CO_2 = 1x$

$CH_4 = 25x$

$NO_2 = 293x$

Although not covered in this paper, Life Cycle Cost Analysis (LCCA) is an effective means of determining the cost-effective option for new projects. It looks at the economic sustainability of a new project or process and provides decision makers with information other than economics to base their decisions.

Direct Reduction Methods

Natural gas is used in many processing operations to not only power equipment but also directly in the process, such as in the glycol regeneration unit. The following sections discuss methods aimed at reducing the amount of natural gas directly used by the plant to reduce emissions. Also, note that any fuel gas saved will end up being sold as sales gas. The simplest way to cut back on natural gas (methane) use is to replace it with another gas like nitrogen or carbon dioxide. First, we will look at opportunities for nitrogen or carbon dioxide to replacement fuel gas. Note that carbon dioxide use is most favorable in facilities that handle large amounts of carbon dioxide like in Enhanced Oil Recovery (EOR) facilities. For the following applications discussed here, nitrogen can be generated on-site or it can be trucked in as liquid nitrogen and used from a bulk storage tank. To achieve the quoted CO_2e savings when using CO_2, the CO_2 must be captured from the process, otherwise the savings would be reduced to what is shown when CO_2 replaces methane venting.

Natural Gas Savings

Flare Purge and Pilot

The flare header is used to capture gas from relief devices and other sources, routing the gas to the flare. The flare system utilizes fuel gas in two major ways: as a purge gas in the flare header and for the pilot flame at the flare tip. The header is operated with purge gas to prevent air from infiltrating the system. The purge gas keeps the header slightly pressurized such that leaks would be outward to the atmosphere, rather than allowing air infiltration. The purge gas is either burned at the flare, generating CO_2, or allowed to escape to the atmosphere, emitting methane, a much more potent greenhouse gas than CO_2. To eliminate these two less than ideal scenarios, an inert gas such as nitrogen or carbon dioxide could be used instead of fuel gas to purge the header and maintain a slight pressure to prevent air ingress.

Purge rates vary depending on flare type and header size, but a typical purge rate for a 200 MMSCFD gas plant would be in the range of 500 SCFH to 1200 SCFH. This equates to 4.32 to 10.37 MMSCF/year. Replacing flare header purge gas from natural gas to nitrogen or carbon dioxide will result in a fuel gas savings of $13k to $31k per year and reduce emissions by 227 to 545 tonnes/year CO_2e assuming for CO_2 that the CO_2 is captured from the process and used.

The pilot flame at the flare tip is maintained to constantly ignite any combustibles from the flare header before being released into the atmosphere. This flame requires a fuel source and fuel gas is most often used. Unlike the purge gas previously discussed, incombustible nitrogen gas is not a feasible replacement for this fuel gas. However, one possible way to reduce the fuel gas used by the pilot flame might be to utilize an autoignition system. These are typically a sparking system that continuously provides a spark to ignite any combustibles that may be released into the flare system.

Pilot gas rates again vary depending on the flare size and type. A typical three pilot system for a 200 MMSCFD gas plant will use approximately 250 SCFH, which is 2.16 MMSCF/year. Eliminating pilot gas will save $6.5k/year in natural gas and eliminate 114 tonnes/year of CO_2e emissions.

Tank Blanket Gas

Tanks can be used to store heavier hydrocarbons (condensate) as well as other liquids used in gas processing (amine, produced water, spent lube oil, etc.). The tanks are filled and emptied over time resulting in changes in the liquid level and vapor space. As the liquid level drops, something must replace the volume of the exiting fluid to avoid creating a vacuum in the tank. Air is less than ideal to mix with hydrocarbons, so fuel gas is often used. When the tank is then refilled the vapor is displaced and typically vented. This provides a potential point to reduce fuel gas use and/or methane/CO_2 emissions. The fuel gas used could be replaced by an inert gas such as nitrogen or carbon dioxide.

For a standard 210 bbl tank the amount of gas needed to blanket the tank at 80 F and 15 psia is roughly 163 SCF. Assuming each tank is emptied 3 times per week, the daily average comes out to about 490 SCFD per tank, or 176 MSCF/year per tank.

Replacing the fuel gas used for blanket gas with nitrogen or carbon dioxide will save $500/year in natural gas costs and eliminate 9 tonnes/year of CO_2e emissions per tank assuming for CO_2 that the CO_2 is captured from the process and used.

Glycol Regeneration Stripping Gas

Fuel gas is sometimes used as stripping gas in the glycol regeneration still. This is done to improve purity of the TEG and improve water removal from the natural gas. The GPSA Databook Figure 20-73 provides a graph for determining glycol purity as a function of the ratio of stripping gas to glycol. Assuming ratios 2.5 and 5 SCF/gal and a TEG circulation rate of 50 GPM, approximately 65 to 130 MMSCF/year are used as stripping gas for glycol regeneration. This gas is ultimately lost to either vent, flare, or thermal oxidizer.

Capturing the stripping gas using a vapor recovery compressor (VRU) and sending it to fuel gas or back into the process could reduce the emissions from either venting or flaring of the stripping gas.

Also, using nitrogen or carbon dioxide as the stripping gas will reduce emissions and save cost as well without the need for a VRU.

Using nitrogen or carbon dioxide as stripping gas will save $200k to $400k per year and reduce emissions by 3420 to 6840 tonnes/year of CO_2e emissions assuming for CO_2 that the CO_2 is captured from the process and used.

BTEX

BTEX (benzene, toluene, ethylbenzene, and xylene) are highly carcinogenic compounds typically found in small amounts in natural gas. TEG has a great affinity to absorb these compounds which are then released during the regeneration step. Since these compounds are carcinogenic, there are tight regulations regarding their emissions. Typically, they are sent to a thermal oxidizer or flare. If these compounds can be condensed, they could be sold as NGLs or condensate or used as fuel in other equipment.

In a typical 200 MMSCFD typical plant, the TEG still produces roughly 1170 lb/hr of a mixture of water and hydrocarbons, including BTEX. In a typical plant this mixture is cooled via air-cooler to condense some of the water out and then sent to the thermal oxidizer (TO) or flare. This typically yields approximately 190 lb/hr of vapor that is then incinerated in the TO. By using a small amount of refrigeration (or even a slip stream from the cryo operations) to cool the TEG still overhead to 40 F, with a three-phase separator, the heavier hydrocarbons, including BTEX, can be extracted and sent to the Y-grade pipeline at roughly 30 BPD, increasing NGL sales by $544k/year. The amount of vapor remaining is reduced to about 66 lb/hr. This reduces the emissions produced in the TO by over 1,300 tonnes/year and saves $75k/year in fuel costs.

Gas Capture

Blowdown Headers for Equipment Maintenance

When equipment is shut down for maintenance, the trapped gas is often vented to the atmosphere. Rather than letting this gas escape, it could be redirected back to a low pressure (LP) compressor, to a VRU, or even routing to the flare or TO will reduce CO_2e emissions over venting to the atmosphere.

For example, a 5,000 hp two-stage reciprocating compressor package with a suction pressure of 200 psig and discharge pressure of 1,000 psig contains approximately 20 MSCF of gas when shut-down and blocked in. If it is shut down and blown down twice a month, that is 480 MSCF/year. A typical 200 MMSCFD gas plant might have eight units (inlet and residue), so that is a total of 3,840 MSCF/year. If simply vented to the atmosphere, that is 2,295 tonnes/year of CO_2e and lost revenue of $12k/year.

The first option that is normally practiced is to blow down the compressor back to the suction header such that other compressors operating in parallel can take the gas and avoid venting some of it.

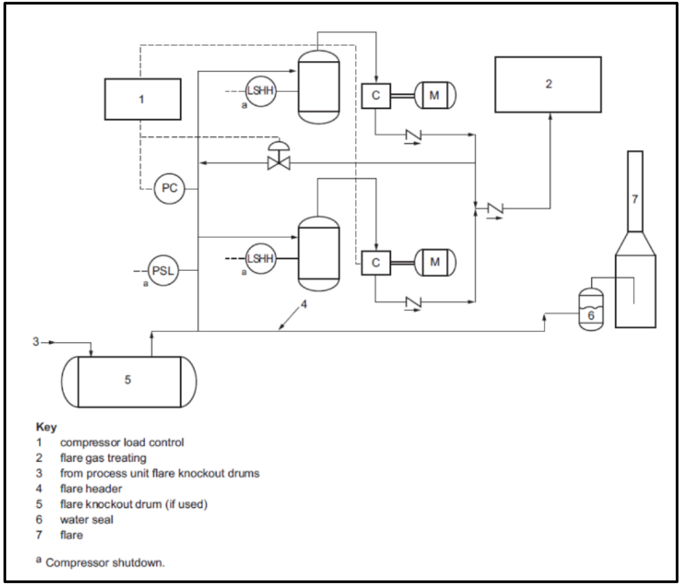
Another option after the initial blowdown to suction or if there are no parallel compressors is to route the blow-down gas to another compressor operating at a lower pressure such as a Low Pressure (LP) or VRU compressor. This would capture some of the gas and greatly reduce the amount that must be blown down. A “maintenance header” could be installed to capture the blow-down gas from various sources and route to a lower pressure compressor.

The remainder of the gas—or if no low-pressure compressor options exist—could be routed to the flare or a TO. Flaring of the gas instead of simply venting it would save 2,100 tonnes/year of CO_2e. A flare connection from the maintenance header or directly from the compressor could be used.

Flare Gas Recovery

Flare gas can be recovered from the flare header before it is combusted using a flare gas recovery system as shown in Figure 1. The basic premise is when the plant is sending gas to the flare the flare header pressure will increase. Pressure sensors on the flare header will activate and load a compressor(s) to reduce the flare header pressure back to normal. The recovered gas is compressed and sent to the fuel system or another destination for use. This is covered in detail in API-521, section 5.7.10 of the seventh edition.

Figure 1
Flare Gas Recovery System



Source – API-521, Pressure-relieving and Depressuring Systems, 7th edition, June, 2020 (Errata 1, November, 2022)

CO_2 Capture

One way to reduce emissions, in particular carbon dioxide emissions, is to directly capture them. Carbon capture and storage (CCS) is a rapidly growing industry that aims to reduce the amount of carbon dioxide present in the atmosphere by collecting it and storing it in underground wells. In gas plants, there are two main sources of carbon dioxide: CO_2 removed from the natural gas during processing, and CO_2 produced during the combustion of fuel in engines and heaters; both of which will be discussed here.

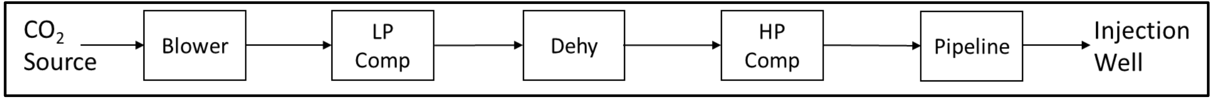
Process CO_2

Many gas processing plants remove CO_2 from the natural gas to meet sales gas or NGL specifications and/or to prevent it from freezing during cryogenic separations. Typically, the removed CO_2 is vented to the atmosphere either directly or through a thermal oxidizer (TO).

This CO_2 could be captured and sequestered underground. Most gas processing facilities are near oil and gas producing fields which have favorable geology for sequestration.

For a 200 MMSCFD plant with 2.5% inlet CO_2 recovering the vented CO_2 results in 94,700 tonnes/year of CO_2e savings. A Block Flow Diagram (BFD) of the typical capture process is shown below in Figure 2.

Figure 2
CO_2 Capture Process



Produced CO_2

Main sources of CO_2 in a gas plant include exhaust from compressor drivers (engine or gas turbine) and heaters (hot oil, amine reboiler, TEG reboiler, regen gas, etc.). For example, a 1150 hp engine produces approximately 4,000 tonnes/year of CO_2e. A 200 MMSCFD gas plant typically has 5,000 to 20,000 hp so CO_2e emissions range 17,400 to 69,600 tonnes/year.

Capturing the CO_2 from exhaust gases is more difficult than capturing process CO_2. But technology is improving for CO_2 capture from exhaust gases.

Indirect Reduction Methods

Most plants utilize fired heaters to provide heat to the process. Better heat integration could reduce fuel gas consumption and thereby lower emissions. The following section discusses approaches to lower emissions by reducing the amount of gas burned as fuel for heat or power.

Waste Heat Recovery and Integration

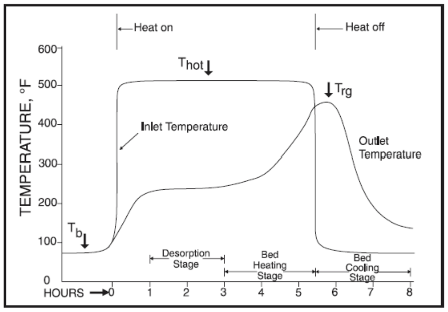
Most plants utilize fired heaters to provide heat to the process. Better heat integration could reduce fuel gas consumption in these fired heaters, saving on both gas and emissions.

Molecular Sieve Regeneration Heat Exchanger

To regenerate the molecular sieves, a heater is used to heat a portion of the dry gas which is then sent to the bed in regeneration. Once this hot gas passes through the sieve, it is then cooled with an air cooler before recombining with the rest of the inlet or residue gas. The temperature of the gas exiting the sieve can remain relatively high. A heat exchanger could be added to the process in which the exiting regen gas can be used to pre-heat the dry gas entering the regen heater. This will reduce the required duty of the regen heater and the air cooler, thus reducing the power and fuel gas needed.

Figure 3 below shows the typical temperature profile in and out of the dehy beds. For the majority of the heating cycle the bed outlet temperature is around 240 F or higher. With dry gas typically at 100 – 120 F, the slip stream regen gas can be pre-heated by at least 100 F or more which reduces the firing load on the heater and saves fuel.

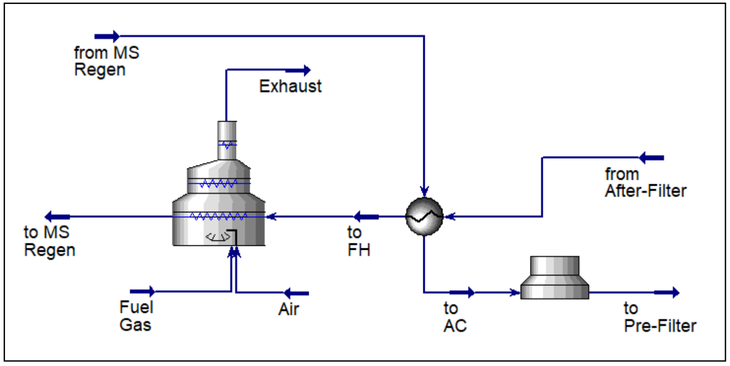
Figure 3
Regen Cycle Temperatures



(Source – GPSA Data Book)

To study the feasibility of this method, a process simulation was performed in Aspen HYSYS. This simulation flowed dry regen gas into a fired heater that would be heated to 550 °F and sent to regenerate the sieve beds. In the case of an additional heat exchanger, the stream exiting the beds (at varying temperatures, depending on the progress of the regeneration cycle) would be directed through an exchanger to pre-heat the gas before going into the heater as shown in Figure 4. The duty on the heater decreases as the regen cycle progresses.

Figure 4
Regen / Regen Heat Exchanger Process Flow Diagram



Based on a typical 200 MMSCFD gas plant the regen cycle was modeled at different times throughout the regen cycle to determine the fuel gas savings. A conservative 20 F approach was used for the new heat exchanger. The heater outlet temperature was set at 550 F. The inlet temperature before heat exchange was 100 F. The results are shown below in Table 1. This assumed an 8 hour regen cycle with 5.5 hours of heating.

Table 1
Regen / Regen Heat Exchanger Results

	Base Case	With Hx	Difference
Fuel Gas (MMSCF/year)	58.8	22.8	36.0
Emissions (CO_2e – tonnes/year)	3093	1893	1199
Fuel Gas Cost ($k/year)	178	109	69

Almost 1200 tonnes/year of CO_2e can be saved while also saving $69,000/year in fuel gas. The fuel gas savings alone makes the project rather attractive and with the emissions savings it is quite attractive.

Hot Compressor Gas for Trim Reboiler

In ethane rejection mode or in propane recovery plants, an externally heated reboiler is required to drive ethane from the NGLs. This reboiler typically uses a heating medium. In an effort to reduce the fuel gas use of the heating medium heater, hot gas between stages of compressors could be used in place of the heating medium in the reboiler.

A simulation was developed comparing the base case (hot oil trim reboiler) to a trim reboiler heated with residue compressor interstage gas. A side stream from the demethanizer feeds to the reboiler and is warmed from 110 °F to 125 °F, with a vaporization rate of about 24% and a duty of 7.1 MMBtu/hr. For the base case, the hot oil is 400 °F flowing at a little over 175,000 lb/hr. For the case of using compressor gas, the hot compressor discharge gas flowed at around 145 MMSCFD at 250 °F.

Shown in more detail in Table 2 below, the results of the simulation indicate a CO_2e savings of over 6,800 tonnes/year. In addition to the emissions savings there is a $393k savings per year in fuel gas. Another added benefit of using this interstage gas is the reduced duty required by the compressor after coolers, which was reduced nearly 35% from 20.4 MMBTU/hr to 13.25 MMBTU/hr.

Table 2
Trim Reboiler Heat Source Comparison

	Base Case (Hot Oil)	With Comp Dischg Gas	Difference
Fuel Gas (MMSCF/year)	129.6	0.0	129.6
Emissions (CO_2e – tonnes/year)	6816	0.0	6816
Fuel Gas Cost ($k/year)	393	0.0	393

Waste Heat Recovery

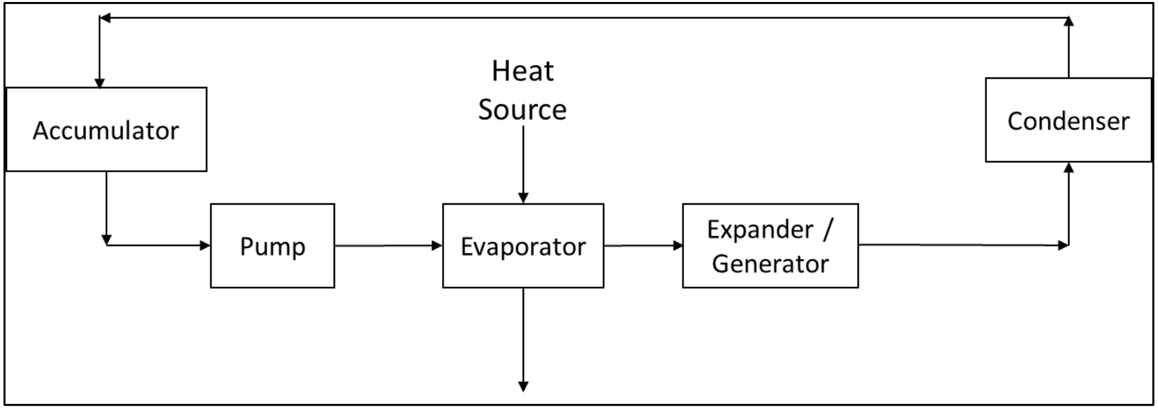
In cases where an engine or gas turbine is used to power compressors or generators, the hot exhaust gas can be used as a source of heat for the plant. Typical exhaust gas is around 1,000 F. The waste heat can be transferred to hot oil, steam generation, or direct heating to save fired heater fuel gas or possibly eliminate a fired heater. Potential heat available from driver exhaust gas can be over 2,000 Btu/hp depending on the driver type, load, and required process temperature.

Using waste heat from a common engine used in the gas processing industry (~1850 hp), approximately 3.0 MMBtu/hr of process heat can be obtained using hot oil heated to 450 F. This would reduce the heat requirements on a fired heater or in a new design eliminate a fired heater. This results in a CO_2e savings of 2,140 tonnes/year and $123k savings in fuel gas costs. And waste heat recovery units can be installed on multiple units to gain additional heat for the process.

Low Grade Waste Heat Recovery

Another option for utilizing waste heat from an engine or gas turbine or low-grade waste heat from the process itself is to capture the heat via the Organic Rankine Cycle (ORC). This process operates similar to a steam cycle, but with a working fluid that can be condensed at ambient conditions and boiled at high pressure by the waste heat or process fluid.

Figure 5
Organic Rankine Cycle



Sources of heat can be exhaust gas from gas engines or gas turbines. As mentioned above typical exhaust gas temperatures are around 1,000 F. Other sources can be compressor discharge gas, heater exhaust, or anywhere heat from a relatively high temperature process fluid is rejected to the atmosphere.

Using waste heat from the same common engine used in the gas processing industry, approximately 220 kW of electricity can be produced. This results in a CO_2e savings of 770 tonnes/year and $197k savings in electricity costs. Where there are multiple compressor units these numbers can be greatly increased.

VFD Drives

Replacing constant speed electric motors with Variable Frequency Drives (VFDs) can lead to power savings which indirectly reduces CO_2 emissions and saves on electricity costs. For example, for a pump or compressor that is recycling a significant amount of flow (50%) is wasting approximately 50% of the power of that pump or compressor. A 100 hp VFD drive motor that eliminates the need for recycling would save approximately 125 tonnes/year of CO_2e and $32k/year in electricity costs at 10 c/kWh.

Improving Operational Efficiency

Modifications to Raise Residue Pressure

Before the residue gas leaves the processing plant, it is compressed to sales gas pipeline pressure specifications. If the cold plant can be modified such that recoveries can be maintained or increased with higher demethanizer / deethanizer pressure, less residue compression would be needed, thus reducing the amount of required energy.

Many older plants operate with older process technology. These processes are not as efficient as currently available processes. They key difference difference with the newer processes is that the demethanizer or deethanizer pressures operate higher than the old technology while achieving the same or higher recovery levels. This reduces residue power requirements which leads to fuel / power savings and a reduction in emissions.

For example, take an older 200 MMSCFD plant operating with inlet pressure of 900 psig, inlet composition of 4 gal/MSCF, and 80% ethane recovery as the basis. Modifications can be made such that the plant can recover 90% ethane, but with a reduction of 900 hp of residue compression. The additional ethane recovery results in approximately $10M/year of additional revenue at $25/bbl. The reduced power requirements reduces CO_2e by 3,292 tonnes/year and saves $190k/year of fuel gas assuming gas engine driven compression.

H_2O Totalizers on Molecular Sieve Systems

Most mole sieve dehydration units switch beds based on time. This works well when operating at or near the design conditions (flow and inlet water content). However, at reduced flow rates or inlet water content, this leads to switching beds before they reach their design adsorption capacity. Using a H_2O totalizer to control bed switching can lead to reduced regeneration cycles saving fuel gas on the regen heater.

By measuring inlet flow and water content into the mole sieve system the amount of water being adsorbed can be totalized over time. Once a bed has reached the set-point (determined from sieve supplier design data) the cycle is advanced and placing the online bed into regeneration mode. Under turn-down conditions, a bed that may be in adsorption mode for 8 hours may increase to 10 or 12 hours depending on the conditions. This leads to less regeneration cycles which is good for sieve life, and also reduced regen heater cycles which leads to fuel savings and reduced emissions.

For a typical 200 MMSCFD gas plant, saving one regen cycle a week leads to 146 tonnes/year in CO_2e emissions and $8k/year in fuel gas savings.

Heater & Thermal Oxidizer Air Pre-Heating

Using air pre-heat on a fired heater or thermal oxidizer (TO) provides significant fuel gas savings resulting in emission savings. Thermal efficiencies up to 97% are possible depending on the application.

A simple thermal oxidizer adds fuel gas to incinerate waste gas for disposal. Fuel gas is added to achieve a temperature that results in the breakdown of the waste gas components. In gas plants this temperature is 1500 to 2000 F. Recuperative thermal oxidizers utilize cross exchange between the exhaust gas and the combustion air. A regenerative thermal oxidizer uses beds to capture exhaust heat and achieve air preheat. At least two beds are required with one adsorbing heat from the exhaust gas and the other pre-heating the air as it flows through it.

Similarly, the same is true for fired heaters with several types of air pre-heat that capture heat from the exhaust and uses it to pre-heat the air.

The resulting savings in emissions and fuel gas costs are summarized below in Table 3 assuming a 10% gain in thermal efficiency for both a thermal oxidizer and a fired heater for a typical 200 MMSCFD gas plant.

Table 3
Air Pre-Heat for Thermal Oxidizers and Fired Heaters Comparison

	Base Case	**With Air Pre-Heat**	**Difference**
Thermal Oxidizer			
Fuel Gas (MMSCF/year)	60.5	51.4	9.1
Emissions (CO_2e – tonnes/year)	3182	2703	479
Fuel Gas Cost ($k/year)	183	156	27
Fire Heater (Hot Oil)			
Fuel Gas (MMSCF/year)	432	389	43
Emissions (CO_2e – tonnes/year)	22720	20459	2261
Fuel Gas Cost ($k/year)	1309	1179	130

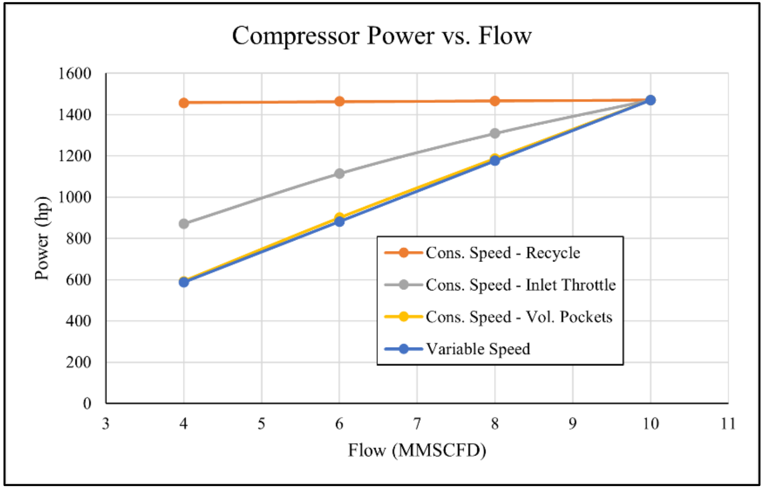
Compressor Turndown Efficiency

Compressors are often designed to handle a specific amount of gas; however, this amount is not always consistently available. There are several methods used to account for a turndown of flow. These include reducing the speed of the compressor, recycling flow, throttling the inlet pressure, and for reciprocating compressors volume pockets. Some of these methods are more efficient than others in terms of required horsepower. Efficient turn-down should be considered in the initial design or modifications can be made later if consistent turn-down operations are required.

There are a number of options available to handle compressor turndown. The first option involves simply reducing the speed of the compressor. This can be applied to electric motors using Variable Frequency Drives (VFDs) as well as gas engines or turbines. The second option uses a recycle stream taken from the discharge of the last stage back to the compressor suction. The recycled flow is added to the inlet flow to maintain the original design flow rate of the compressor. Another option involves reducing the suction pressure by using a throttle valve. The net effect is keeping the volumetric flow (e.g. ACFM) near the design point. The last option, applicable to reciprocating compressors, is the use of volume pockets on the compressor cylinders.

A compressor was simulated in Aspen HYSYS as a three-stage reciprocating compressor with a design suction pressure of 100 psig, suction temperature of 80F, interstage temperatures of 120F, and a discharge pressure of 1000 psig. The design flow rate was 10 MMSCFD of water saturated 3 gal/MCF gas, and cylinder dimensions were fixed around the design parameters. The flow rate was decreased, and parameters adjusted for each turn-down option and the horsepower calculated. The results are given below in Figure 6.

Figure 6
Comparison of Compressor Turn-down Options

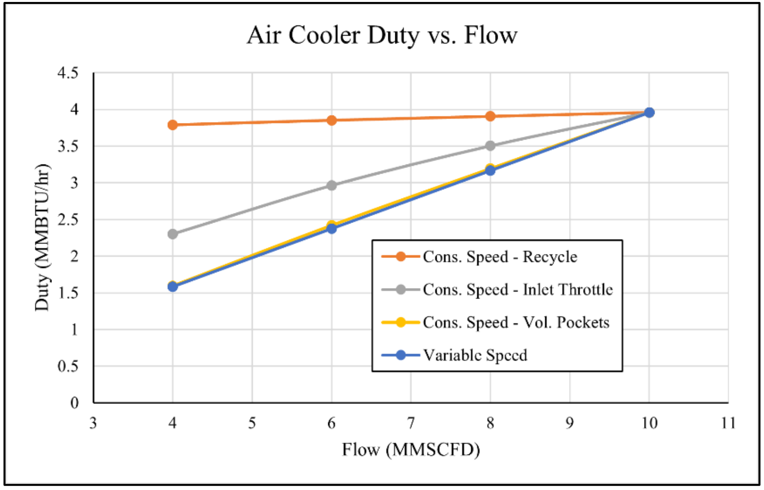


The figure above shows the power requirements of the various compressor options during turn-down. The least efficient option—using a recycle valve—showed no reduction of the power with turn-down of flow. Throttling the suction pressure reduced the required horsepower to some extent, but the use of volume pockets was the most efficient of the three constant-speed modifications. The variable speed option was also very efficient and almost identical in horsepower savings to the use of volume pockets with a constant speed unit.

For a gas-engine driven compressor operating at 50% of its capacity, the variable speed will save approximately 700 hp. That is a reduction of 49 MMSCF/year of fuel gas, 2560 tonnes/year of CO_2e, and fuel gas savings of $148k/year. For a constant speed electric motor driven compressor there would still be an associated reduction of CO_2e at the power generation facility and a reduction in electricity costs.

In addition to the horsepower savings discussed above each option has a different impact on the interstage cooling as shown in Figure 7. The recycle option has no effect on the cooling load with turn-down. Suction throttling has some benefit, but the volume pockets and variable speed had the most impact. For all but the recycle option, the reduced duty could mean shutting down fans, or slowing down fans if variable speed. Or it could lead to cooler interstage temperatures which would result in additional compressor horsepower savings by increasing efficiency.

Figure 7
Interstage Cooling Duty For Different Turn-down Options



Conclusions

As shown in this paper there are many ways to save on emissions in gas processing facilities. Many of these options also have the additional benefit of saving costs on fuel or electricity resulting in economic justification. Based on a typical 200 MMSCFD gas plant, the CO_2e savings can range up to 94,700 tonnes/year. Fuel gas savings can be greater than $500k/year, meanwhile increasing revenue due to less fuel gas consumption and higher NGL yield. Table 4 below summarizes the options discussed in this paper.

Table 4
Summary of Emssion Saving Options

Option	**CO_2e Savings (tonnes/year)**	**Cost Savings ($k/year)**
Flare Purge	227 – 545	13 - 31
Pilot Gas	114	7
Blanket Gas	9	1
TEG Stripping Gas	3419 – 6837	197 - 394
BTEX Chilling*	1300	544
Blow-Down Header (Recycle)	2295	12
Blow-Down Header (Flare)	2100	0
Flare Gas Recovery	n/a	n/a
CO_2 Capture (amine)	94700	0
CO_2 Capture (exhaust)	4000 - 70000	0
Regen / Regen Hx	1199	69
Hot Gas Heat Source	6816	393
Waste Heat Recovery	2140	123
WHR – ORC*	770	197
VFD	125	32
Higher DeC1/2 Pressure*	3292	190
H_2O Totalizer	146	8
RTO	479	27
Heater Air Pre-Heat	2261	130
Compressor Control	2560	148

* These options also produce additional revenue.

The numbers presented in this paper are indictive and are presented for comparison and indication of magnitude. The results will be different for each facility and each application. These results show that there are numerous opportunities to reduce emissions in gas processing facilities.

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