ConocoPhillips

ConocoPhillips Field GHG Reduction Projects

Project Partners:

CCEMC
Climate Change & Emissions Management Corporation

CETAC-WEST

Final Report

Company: ConocoPhillips Canada
Principal: Sean Hiebert
Completion date: December 31, 2015
Report Completion Date: July 29, 2016
Total Project Cost: $14,639,000
CCEMC Contribution: $6,971,000

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Summary

In 2010 ConocoPhillips Canada (CPC), Alberta's Climate Change & Emissions Management Corp.(CCEMC) and Canadian Environmental Technology Advancement Corp.-West (CETAC-WEST) embarked on a foray into combined efficiency gains and greenhouse gas reductions in oil and gas production. Working samples chosen from a vast ConocoPhillips array of Alberta assets of all sizes and ages provided live proving grounds.

Shared-cost field trials of 10 capital and operational initiatives ended on schedule and budget five years later in environmental and economic results that stood out as double the team's original target. The projects achieved annual emissions cuts equivalent to over 90,000 tonnes of carbon dioxide and enhanced asset efficiency, and showed ways to apply their lessons throughout the industry. Average costs were cut in half from the original target to roughly $7 per tonne of GHG reduction. The technologies trialed are summarized with corresponding GHG reductions and associated costs in Figure 1.

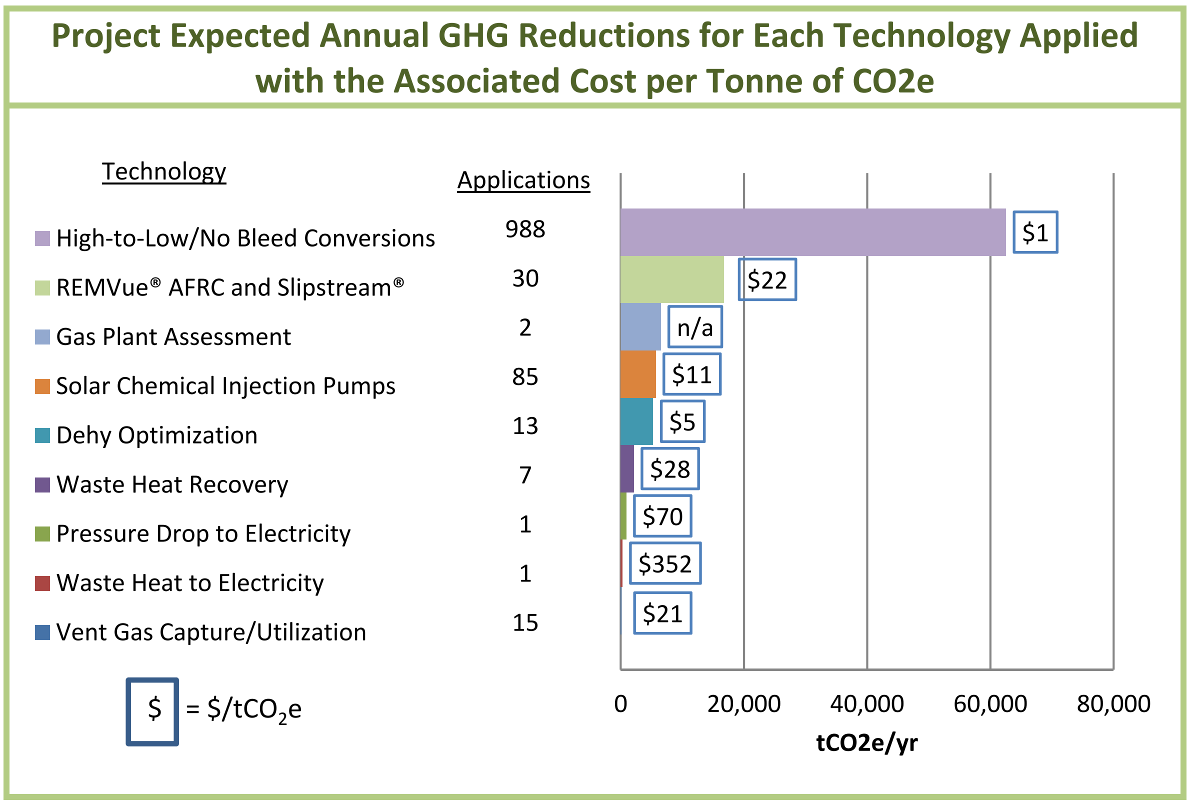


Figure 1. Summary of Technology Results

The strongest environmental performances arose from initiatives that turned out to be pioneer efforts at tackling a priority cleanup target the Alberta and United States governments set for the petroleum industry in late 2015 and early this year. Both jurisdictions take aim at fugitive emissions of methane, which is deemed to be 25 times more potent than carbon dioxide as a greenhouse gas responsible for global climate change. The Alberta pilot projects identified culprits and created a low-cost routine for stopping them swiftly by carrying out more than 1,100 examples of arresting leakage at an accelerating pace as the strategy matured.

The field trials taught organizational as well as technical lessons. While the CPC and CCEMC each covered half of the $14-million cost, CETAC-WEST provided project accountability and support. Throughout a tumultuous period of energy price and corporate personnel change, quarterly meetings sustained interest in the field projects and brought independent specialist expertise to bear on problems.

The successes also contributed to widening oil and gas corporate culture to make combined environmental and economic behavior rewarding for all concerned. Project participants committed to sharing all technical and organizational lessons in response to rising public expectations of generally improving production practices that rule out use of environmental advances as competitive trade secrets.

Project Goals

This project was set up with the following goals:

1. Execute projects to reduce Greenhouse Gas (GHG) emissions at Upstream Oil and Gas facilities in ConocoPhillips Western Canada Gas Operations, and
2. Encourage widespread industry adoption of GHG reduction projects by sharing the results and learnings with a wide industry and government audience.

The three factors that have contributed to successful completion of this project are:

A. *Technology Selection*

ConocoPhillips set out to install and field-test several technologies to reduce GHG emissions at certain types of facilities that are common to all conventional oil and gas operations in Alberta. The technologies that were chosen for this project were at the time new technologies that were potentially viable for the whole industry, but had not been widely adopted.

B. *Team*

ConocoPhillips executive and management personnel were devoted to this project and committed the necessary resources to ensure successful project implementation:

- A full time engineering team dedicated to energy efficiency and emissions reductions for ConocoPhillips Canada with a track record of successful energy efficiency and emissions reduction projects.
- In-house engineering to assist with project front-end scoping and design.
- Infrastructure and facility engineers to help in the execution of the projects.
- Involvement from field operations staff in all phases of the project.

This project was completed in collaboration with CETAC-WEST. CETAC-WEST has demonstrated leadership in energy efficiency since 2001 and assembled a strong team of energy efficiency experts who collaborated on the development of the CAPP-endorsed Fuel Gas “Best Management Practices.” The Experts that participated throughout this project were: Accurata Inc., Sulphur Experts Inc., REM Technology Inc., Sirius Instrumentation and Controls Inc., RCL Environmental and Process Ecology. CETAC’s role was to provide support in the planning and execution of the different technologies and to organize the industry roll-out of the results through a knowledge sharing workshop, which was held on December 4, 2015 in the CPC Auditorium.

C. *Outcomes*

The project set out to deliver over 50,000 tonnes of GHG reductions per year with an estimated total of over a megatonne of GHG reductions over the service lives of the facilities. This project further leveraged the economic and environmental impacts of the technologies by sharing the learnings with the Upstream Oil and Gas industry and government departments to encourage the more widespread application of these technologies.

Project Details

The project started in 2010 with an initial targeted completion by 2013. However, more time was needed and ConocoPhillips requested extensions from CCEMC, which were ultimately granted to the end of 2015. Table 1 outlines the important dates of this project.

Table 1. Important Project Dates

	Date
Expression of Interest	Approved – September 2010
Full Project Proposal	Approved – February 2011
Knowledge Sharing Workshop	December 2015
Project Completion	December 2015
Report Submission	June 2016

The project included the implementation of over 10 different technologies/initiatives and approximately 1100 installations. The total project cost was ~$14,000,000 with a contribution of ~$7,000,000 from the Climate Change and Emissions Management Corporation and ~$7,000,000 from ConocoPhillips Canada. A summary of the different installations and associated GHG reductions can be found in Table 2.

The cumulative number of GHG Reductions was verified by Cap-Op Energy and an independent report was provided to CCEMC. The cumulative number does not include projects such as the Waste Heat to Electricity or Waste Heat Recovery because the assets were sold during the course of the project and Cap-Op Energy was not able to verify the final results. In these cases, the data that was collected during the time of operation under Conoco control was analyzed to determine emission reductions achieved.

Highlights of ConocoPhillips' operational experiences with field testing the technologies together with their economic and environmental impacts were presented at a Calgary Workshop on December 4, 2015. The Workshop was facilitated by CETAC-WEST which was involved with its group of industry experts throughout the project in various aspects such as:

- Engineering and design.
- Quarterly review meetings that were held between all project parties. The purpose of these meetings was to evaluate the technologies and projects as they

were being completed and confirm the measures being taken to ensure project success. Meetings were held on a monthly basis in 2015 to help prepare for the Workshop.

- Summary reports that were developed for each technology/initiative. These reports were developed and reviewed by CETAC-WEST and industry experts based on the information provided by ConocoPhillips Canada. These reports were the foundation for the Workshop content as well as the development of this Final Report.
- Dry run presentations of the technology implementation highlights, that involved ConocoPhillips, CETAC-WEST, and industry experts to summarize the key messages for industry.
- Working with ConocoPhillips, the Workshop facilitator, Workshop participants and Workshop Panel members to clarify the content and key messages to be delivered and discussed during the Workshop.

Table 2. Project Results

Technology / Initiative	Number of Installations	Cumulative and Verified GHG Reductions Up to December 2015	Expected Annual GHG Reductions (tCO_2e/yr)	Expected GHG Reductions over a 20 year life (tCO_2e)	GHG Reduction Cost ($\$/tCO_2e$)	Project Cost	Project Cost with Burden Distribution[1]
High-to-Low/No Bleed Instrument Conversions	988	71,075	62,551	1,251,020	$1.3	$1,615,000	$1,698,540
Dehy Optimization	13	9,401	5,278	105,560	$4.8	$508,000	$534,278
Solar-Powered Chemical Injection Pumps	85	6,615	5,698	113,960	$10.7	$1,215,000	$1,277,849
Gas Pneumatic Pump Vent Gas Capture/Utilization	15	122	159	3,180	$21.4	$68,000	$71,517
25 Engine Fuel Management Systems (REMVue AFRC) and 5 Vent Gas Engine Air Intake (SlipStream)	30	40,146	16,788	335,760	$21.5	$7,218,000	$7,591,372
Waste Heat Recovery	7	0[2]	2,157	43,140	$27.9	$1,203,000	$1,265,229
Waste Heat to Electricity[2]	1	266	266	5,320	$351.7	$1,871,000	$1,967,783
Pressure Drop to Electricity[3]	1[3]	0	924 [3]	19,480 [3]	$70 [3]	$99,000	$104,121
Gas Plant Assessment[4]	2[4]	0	6,500 [4]	124,000 [4]	-	$122,000	$128,311
TOTAL	**1,139**	**127,625**	**92,897**	**1,857,940**	**$7.4 (average)**	**$13,919,000**	**$14,639,000**

[1]The CCEMC project included requirements such as 3rd party GHG verification, industry wide workshop and others that added additional costs to the overall project. These costs were distributed among all the different projects.

[2]Cap-op was not able to verify due to a change in ownership of the assets. Therefore data collected during the time of operation under CPC control was analyzed to determine emission reductions achieved.

[3]Project was never implemented (Not added to total)

[4]Project was completed, however recommendations were never pursued and reductions are not included in the totals. A full report on the gas plant audit and checklist was provided to ConocoPhillips.

Field GHG Reduction Projects

Gas Plant Assessment

Report Prepared by: Sulphur Experts, ConocoPhillips Canada, CETAC-WEST

Project Data Provided by: ConocoPhillips Canada

Introduction

Integrated Audits, in which a multidisciplinary team of experts combine their knowledge and expertise in undertaking a facility wide energy audit, have proven to be an effective tool in improving operational efficiency at large scale gas plants in Alberta and the US. In more than 20 of such audits, energy savings of about 15% have typically been identified. This project was designed to establish if a suitably scaled program would be a useful tool at small, and often unattended, gas plants in Alberta. In particular, there was a need to determine if the cost of conducting an energy audit could be economically justified and if identified improvements could be implemented and sustained at remote and unattended locations. ConocoPhillips was also interested in preparing a Best Management Practices checklist that is operator friendly as a tool to identify energy reduction opportunities.

The two Sweet Gas plants targeted for this project were readily accessible and are typical of the small Sweet Gas plants that are owned by ConocoPhillips in Alberta and, like many gas plants in Alberta, have experienced a decline in raw gas deliveries.

Gas Plant

Project Details

At both gas plants the more significant energy consumers are the result of gas compression, refrigeration and glycol dehydration. Combined, these elements are responsible for almost all of the fuel consumption and CO_2 emissions. In addition, in terms of GHG emissions, it is well known that fugitive emissions and vents offer significant potential for reduction.

In light of the above, the primary focus of this energy assessment was an evaluation of:

- Natural gas engines driving gas and refrigerant compressors.
- Refrigeration and fractionation systems.
- Glycol dehydration including both ethylene and triethylene glycol systems.
- Fired heaters.
- Fugitive and vented gas emissions.

In addition, the energy assessment included an evaluation of a simplified Best Management Practices (BMP) checklist. The purpose of this checklist was to determine whether operators would use this to establish if equipment was performing at or close to optimum levels and potentially identify GHG reduction opportunities.

The assessment was conducted by individuals and organizations with a broad range of expertise and experience in the Alberta oil and gas industry. The unit operations and companies that assessed these unit operations are summarized in Table 3.

Table 3. Companies Used to Assess Gas Plant

Unit Operation/Expertise	Organization
Glycol Evaluation	Process Ecology
Refrigeration and Fractionation	Sulphur Experts
Fugitive Emissions and Venting	GreenPath Energy Ltd
Fired Heaters	Energy Experts
Compressors	Accurata Inc.

The project commenced with a couple of meetings to analyze the plant process flow diagrams and start designing the BMP checklist. Afterwards there was an initial site visit to collect data, engage operating personnel in the process and confirm the objectives and schedule for the audit. This was followed by the on-site audit that was conducted over a two-day period. The field portion of this project involved the collection of field data, conducting measurements and performing tests on selected equipment such as heater efficiency testing and quantification of fugitive emission leaks and venting. Operating personnel were encouraged to participate in all activities and to identify issues and impediments they faced.

Control Valve

At the conclusion of the field data gathering and measurements, detailed analyses of the data and recommendations were prepared. Potential fuel gas, electrical purchases and GHG reductions were estimated as shown in the Results section.

Results

Throughout this report the results will be presented in “SAID” and “DID” columns. “SAID” refers to the original expectations that were set in the proposal submitted to CCEMC. “DID” refers to the results that were achieved throughout the program.

The overall project expectations and results are summarized in Table 4.

Table 4. Overall Gas Plant Assessment Expectations & Results

	SAID	DID
Projects Completed	2	2
Potential GHG Reductions	1,000 tCO_2e/yr.	6,500 tCO_2e/yr.
Cost Abatement *	n/a	n/a

*Project was completed, however recommendations were never pursued. A full report on the gas plant audit and checklist was provided to ConocoPhillips.

The following Table 5, presents a breakdown of the opportunities for fuel gas, power and GHG reductions.

Table 5. Summary of Fuel Gas, Power, and GHG Reduction Opportunities

Process Unit	Gas Plant	Potential Savings			
		Fuel Gas reduction (e^3m^3/yr)	Value ($/year)[1]	tCO_2e/yr	Value ($/year)[2]
Glycol Dehydration and Regeneration	Huxley	24	$2,960	44	$1,320
	Ghost Pine	103	$12,890	192	$5,760
Refrigeration and Fractionation	Huxley	215	$26,430	401	$12,030
	Ghost Pine	29	$3,590	54	$1,620
Fugitive and Vented Emissions	Huxley - Fugitives	27	$3,320	458	$13,740
	Huxley - Vents	80	$10,907	1,365	$40,950
	Ghost Pine - Fugitive	153	$18,800	2,593	$77,790
	Ghost Pine - Vents	34	$4,180	576	$17,280
Fired Heaters	Huxley	Nil[3]	Nil[3]	Nil[3]	Nil[3]
	Ghost Pine	Nil[3]	Nil[3]	Nil[3]	Nil[3]
Compressors	Huxley	409	$50,305	762	$22,860
	Ghost Pine	Nil[4]	Nil[4]	Nil[4]	Nil[4]
TOTAL		**1,074**	**$133,582**	**6,445**	**$193,350**
Refrigeration Additional Electrical Reduction	Huxley	197	$9,845	128	$3,840

[1] Based on an Alberta Reference price of $3.60/GJ

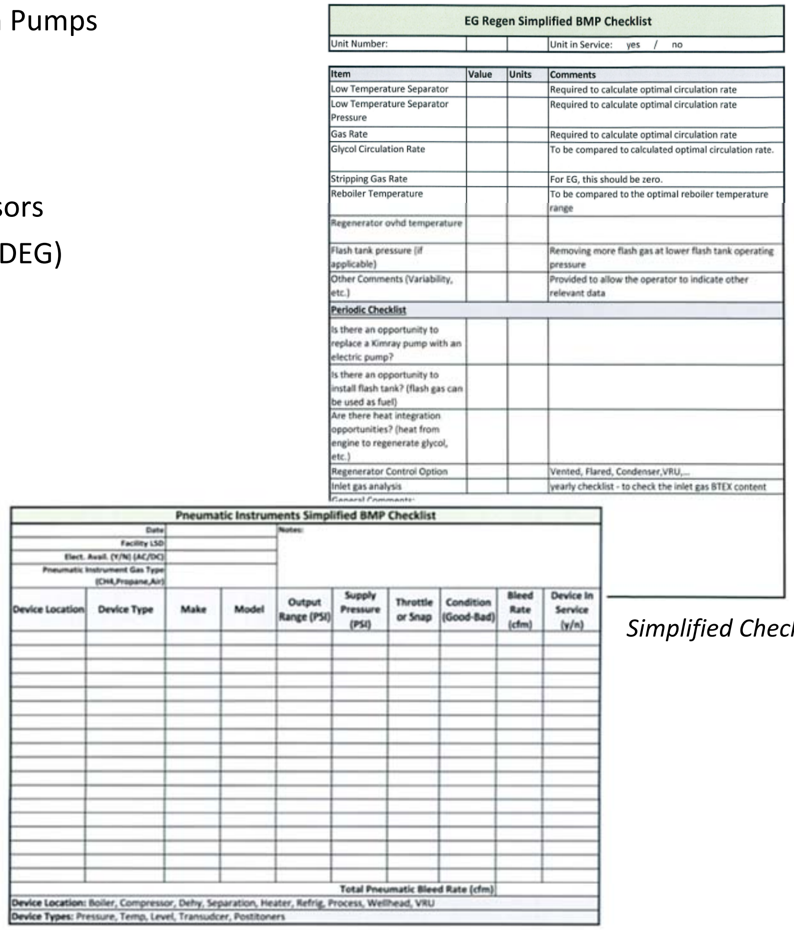
2 Based on $30/t

3 Fired Heaters savings accounted for in Glycol Regeneration

4 Additional opportunities identified have a very long term payback period

As a result of this project, a series of “Simplified Checklists” was developed and refined. These checklists were broken down by unit operations and include:

- Pneumatic Instruments
- Chemical Injection Pumps
- Flaring
- Fired Heaters
- Indirect Heaters
- Engines/Compressors
- Dehydration(TEG/DEG)
- EG Regen
- Fractionation
- Refrigeration
- Lighting
- Building Heaters
- Fugitive Emissions
- Tanks
- Well Sites
- Oil Batteries



EG Regen Simplified BMP Checklist

Unit Number:			Unit in Service: yes / no

Item	Value	Units	Comments
Low Temperature Separator			Required to calculate optimal circulation rate
Low Temperature Separator Pressure			Required to calculate optimal circulation rate
Gas Rate			Required to calculate optimal circulation rate
Glycol Circulation Rate			To be compared to calculated optimal circulation rate.
Stripping Gas Rate			For EG, this should be zero.
Reboiler Temperature			To be compared to the optimal reboiler temperature range
Regenerator ovhd temperature			
Flash tank pressure (if applicable)			Removing more flash gas at lower flash tank operating pressure
Other Comments (Variability, etc.)			Provided to allow the operator to indicate other relevant data
Periodic Checklist			
Is there an opportunity to replace a Kimray pump with an electric pump?			
Is there an opportunity to install flash tank? (flash gas can be used as fuel)			
Are there heat integration opportunities? (heat from engine to regenerate glycol, etc.)			
Regenerator Control Option			Vented, Flared, Condenser,VRU,...
Inlet gas analysis			yearly checklist - to check the inlet gas BTEX content

General Comments:

Pneumatic Instruments Simplified BMP Checklist

Date		Notes:
Facility LSD		
Elect. Avail. (Y/N) (AC/DC)		
Pneumatic Instrument Gas Type (CH4,Propane,Air)		

Device Location	Device Type	Make	Model	Output Range (PSI)	Supply Pressure (PSI)	Throttle or Snap	Condition (Good-Bad)	Bleed Rate (cfm)	Device In Service (y/n)
							Total Pneumatic Bleed Rate (cfm)		

Device Location: Boiler, Compressor, Dehy, Separation, Heater, Refrig, Process, Wellhead, VRU

Device Types: Pressure, Temp, Level, Transudcer, Postitoners

Simplified Checklist

Gas Plant

ConocoPhillips is planning a wider-scale internal implementation of this tool in order to further refine and tune for each facility type. They are planning to integrate this tool in the ConocoPhillips GHG opportunity database in order to identify, log/track GHG reduction opportunities within their operations and assist with near/long-term GHG reduction strategy planning.

“Golden Nuggets”/Project Takeaways

- **Applicability of the Integrated Audit Concept:**

  The essential facets of the Integrated Audit are applicable to, and readily transferred to small scale gas plants. Project scoping is a necessary component in order to control costs.

- **Data Gathering and Measurement**

  - Most of the required process data was readily available at the plants and/or by accessing the ConocoPhillips SCADA systems.
  - Equipment data for some of the older compressors was difficult to obtain even from vendors.
  - Field measurements and testing are readily performed by simple instruments.

- **Field Staff Involvement**

  Operating staff at both sites were supportive of the program and took advantage of the learning opportunity afforded by working with the experts.

- **Simplified Best Management Practices (BMPs)**

  A checklist was developed for ConocoPhillips to use and further develop in the future. However, with the complexity of some process units and the range of operating conditions, it was not feasible to develop such a comprehensive simplified BMP checklist. For example, in the dehydration unit, operational personnel focus on the dew point / freeze protection performance of the system, whereas the BMP checklist seeks to optimize glycol regeneration to improve efficiency. This disconnect in primary objectives can lead to lack of support from field personnel.

REMVue® Air Fuel Ratio Controllers

Report Prepared by: Accurata, ConocoPhillips Canada, CETAC-WEST

Project Data Provided by: ConocoPhillips Canada

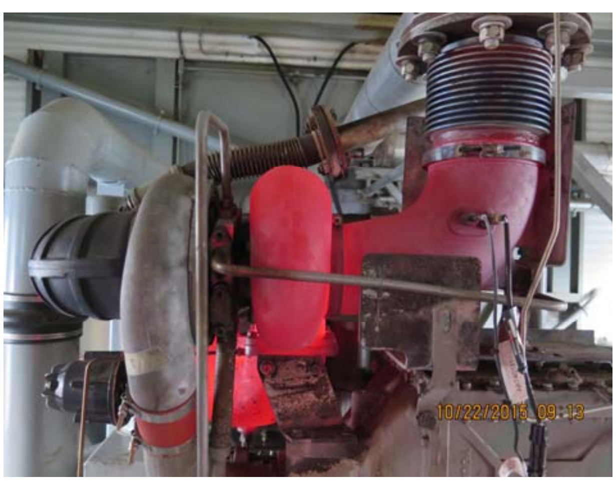
Introduction/Technology Description

The engine management system technology employed in these studies was provided by REM Technology Inc (RTI). They provided the REMVue® 500 control platform, a proprietary range of products developed and owned by Spartan Controls. The pre-chambered spark plugs are also a proprietary product of Spartan Controls, called ECO-Plugs. Engine controls are complex and not fully understood by most industry workers who sometimes assume all AFR (air fuel ratio) systems are alike. ConocoPhillips employed the REMVue® products because no other system is available that offers comprehensive adaptive controls that may be applied to existing and new engines. These products have been proven in previous installations to have a broad scope and deliver the best results in the industry.

Control Panel

The REMVue® technology controls the fuel flow to the engine and matches it to the air flow to manage the air fuel ratio. In addition, the ignition may be controlled as well to compensate for variable load conditions and fuel quality. A mass flow meter is employed on the fuel delivery system that measures the flow and can be used to sense changes in fuel density. Thus the engine management system is adaptive to changes in ambient, operating and fuel quality conditions.

Although the technology can be installed on any gas fired engine, it will not necessarily produce fuel savings unless something is changed in the way the engine operates. Small savings in fuel consumption (1% to 2%) can be achieved by more accurate speed control. Greater fuel gas savings (10% to 20%) can be obtained by running open chamber rich burn engines with a leaner air fuel ratio. The percentage of fuel savings is variable because it depends on how rich the air fuel ratio is set before the conversion. As seen in Figure 2 a richer air fuel ratio as a starting point will produce a larger fuel consumption reduction. Since the engine is inherently less stable at leaner air fuel ratios, it is imperative to incorporate adaptive controls in the engine management system to provide reliable and predictable operation.



Engine Before REMVue Installation

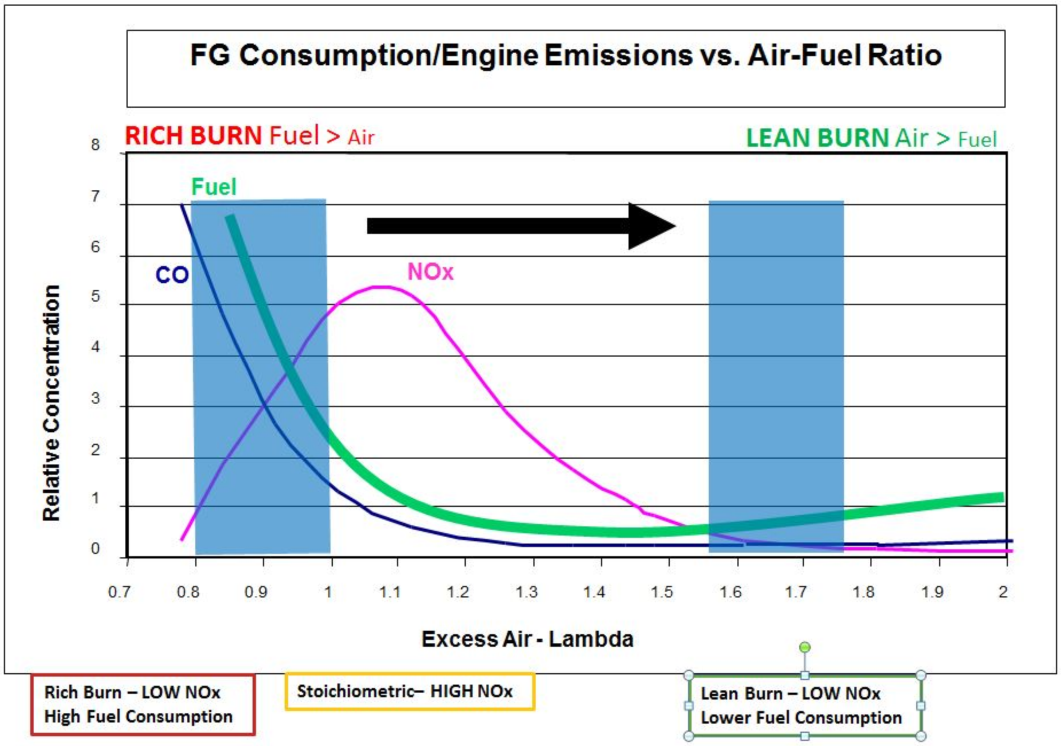


Figure 2. FG Consumption/Engine Emission vs. Air –Fuel Ratio

When the air volume is increased for combustion at the leaner air fuel ratios, it will reduce the cylinder head temperatures. Lower cylinder head temperatures result in cooler engine operating conditions. If predictive maintenance practices are employed, the lower operating temperatures can yield an increase in service life with extended service intervals. Data trending is also often enhanced with the installation of an electronic control system. The enhanced analytical aspects available via the data trends can help manage a predictive maintenance program.

Engine

Installations with rich to lean conversions have consistently produced at least 5% reduction in fuel consumption with typical fuel savings in the 12% to 15% range. Operators report improved reliability and ease of operations. The adaptive controls require less operator intervention to keep the engines running during suboptimal operating conditions. The engine management system also enhances ease of starting for engines that are difficult to start.

ConocoPhillips has also been experimenting with a new pre-chambered spark plug developed by Spartan that is currently in development field trials. It appears to be a viable technology for running leaner air fuel ratios with the result of additional reductions in fuel consumption and NOx emissions.

Project Details

ConocoPhillips has installed 25 air-fuel ratio (AFR) systems with the assistance of CCEMC funding. Their total fleet of engines equipped with this AFR technology numbers about 75. They are installed on a variety of engine models. The most common engine type is a Waukesha GSI engine but they have also installed the systems on Caterpillar open chamber and Waukesha pre-chambered engines.

One field trial involving the pre-chambered plugs was performed on a Waukesha 7042GL pre-chambered lean burn engine. The GL cylinder heads were replaced with open chamber heads from a Waukesha 7042GSI. Waukesha's complex and maintenance intensive GL fuel delivery system was replaced with the REMVue® engine management system. Fuel consumption was reduced and reliability was enhanced.

The typical installation will require modifications to the fuel gas system with a control valve and a mass flow meter. The exhaust waste gate is also replaced with a control valve. This exhaust bypass valve is used to control the speed of the turbocharger and the subsequent delivery of air for combustion. The work is normally executed during a planned outage for maintenance or a turn-around to minimize production losses.

A site visit is required to assess the site, the engines and its potential for an AFR installation. Specialized skills and experience should be sought for the assessment. Spartan staff may be relied upon for expertise and experience but their focus is not on providing engineering design services. Spartan will prepare control panel schematics for the installation.

ConocoPhillips utilized a common contractor on all sites when possible for the installations. Their construction coordinators and inspectors were also common to encourage repeatability and consistency. ConocoPhillips has also standardized on replacement of the compressor control system and ignition system along with the air-fuel ratio installation. A stand-alone air-fuel ratio control system is available if desired. The uncertainty associated with construction aspects can be significantly reduced if the installation crews are experienced with the product and how it is installed.

Results

ConocoPhillips advised that GHG reductions have averaged 702 tCO_2e/year, per engine, for the sites receiving modified air-fuel ratio controls. Cost recovery is achieved via a reduction in fuel consumption which, in turn, may be sold as produced gas. The reduction of combusted fuel also provides a GHG reduction. Protocols for credits attributed to the GHG emission reductions are in place. Therefore additional cost recovery can be achieved via GHG credits. These air-fuel ratio installations can achieve cost recovery in two to four years depending on the natural gas rates, the value of GHG credits and the volume of fuel savings achieved. The sensitivity of the economics to changes in GHG credit rates becomes more significant when natural gas prices are lower. However, fuel consumption reductions will always provide cost recovery even if GHG credits are revoked.

It should also be noted that the cost of the installations as well as the fuel gas savings are widely variable. Attempting to predict the economics for all sites would thus clearly be a challenge. A conservative approach would be to perform a sensitivity analysis so that a range of solutions can define the possible outcomes. That would be appropriate for a single site installation. If a fleet conversion is considered, then the use of average savings could be used with some confidence.

Five REMVue® sites also had a Vent Gas Enginer Air Intake (SlipStream®) system installed. Therefore, the GHG reductions from the 25 REMVue® installations also include the reductions from 5 SlipStream® installations. Table 6 Below shows the overall reductions of the projects.

Table 6. Overall REMVue and SlipStream Expectations and Results

	SAID	DID
Projects Completed	20	25 REMVue+5 SlipStream
Cumulative and Verified GHG Reductions up to Dec. 2015	n/a	40,146 tCO_2e
Potential GHG Reductions	10,526 tCO_2e/yr.	16,788 tCO_2e/yr.
Cost Abatement	\$15.58/ tCO_2e	\$21.50/ tCO_2e

"Golden Nuggets"/Project Takeaways

An enhanced engine management system is beneficial when fuel consumption can be reduced by implementing a leaner air-fuel ratio or when fuel quality is poor or variable. A realization of value is earned in these cases by improvements in reliability and automation. Competing engine management systems do not deliver the full range of benefits that the REMVue® can offer. Caterpillar's latest technology platform in the ADEM A4 comes closest but it is designed for their large pre-chamber engines.

Caterpillar's ADEM systems are not suitable for retrofit to engines made by other manufacturers.

Certain engines like older White Superior brands are also known for hard starting characteristics. Multiple start attempts, sometimes spanning over several hours, are common to get the engine started. These engines will start easier with an improved engine management system. The volume of natural gas used to turn the starters can be significant and reducing the starting effort can save the raw natural gas vented to atmosphere during the starting sequences. Some open chamber engines are already equipped to run at lean air fuel ratios but their engine management systems are not adaptive. Enhanced reliability and the benefits of automation are still available to justify the installation of a REMVue® system.

The sites with larger engines provide better economic justification because their fuel consumption will be a larger volume and so will the savings. The installation cost is greatly affected by the experience of the field contractor with the installation of the systems. It is common that field staff insist on using local contractors that they are familiar with. While that yields satisfactory results at reasonable costs for tasks they normally perform, it does not hold true for doing engine conversion installations. This stems from the fact that many industry workers lack a sufficiently comprehensive understanding of engines and engine controls, much less those required for this specific product. Companies should consider the cost of training the installation contractors in their estimates and then make their decisions. Cost increases of more than 30% may be expected when using inexperienced field installation crews.

The duration of the time available for the installation as well as the other activities planned at the time will also affect the installation. If the panel work is planned during an overhaul it should be expected that too many people will be working at close quarters to expect optimum construction efficiencies. Running two shifts between the activities could be considered to keep everyone working with less interference.

Start-up considerations will also be more complicated when the control system is replaced as well as major engine work planned. ConocoPhillips found that installing just the stand-alone AFR module as an addition to the existing compressor control system appeared to reduce capital cost but that the time it took to commission the systems and get everything operating together would outweigh the purchase price savings when the additional labor, standby time and lost production was included in the accounting. The total installation cost for an AFR panel alone is roughly the same as replacing the entire control system. ConocoPhillips elected to standardize on replacing the compressor control system along with the ignition system to avoid the incompatibility issues and the extra costs associated with those aspects. This also resulted in enhanced automation for units old enough to be equipped with pneumatic or obsolete electronic control systems.

A challenge with every installation is to measure how effective the modifications were. ConocoPhillips elected to employ a conservative estimate of the GHG emission reductions by adopting a recommended value by the Cap-Op Group to avoid the cost of measuring the savings. The average emissions reduction per unit used by Cap-Op is 243.4 tCO_2e per year. That is significantly more conservative than the engines using measured pre- and post-audits. Review of the data also shows a wide dispersion of results so an average number could be applicable for fleet global results but that number will certainly not apply to an individual unit. As mentioned previously, the type of engine and the as-found AFR setting will determine the magnitude of the fuel consumption reduction. It is suggested that the very conservative nature of the Cap-Op estimates warrants performing the pre- and post- audits.

Two aspects are required to collect the data. First, audits conducted before and after the retrofits are needed to qualify the initial installation. It is imperative that one of the audits is performed over a load map so that results at comparable operating conditions are available. If the results are not at the same operating points, then the data is not valid. That is virtually impossible to attain for a variety of practical reasons. Therefore the difference in BSFC is used to calculate the difference in fuel consumption. That calculation should be within 5% of the actual difference when load or RPM are not exactly matched.

Second, if electronic data collection with remote monitoring is not provided, then it is unlikely that the data will be collected to ascertain ongoing performance. That performance is useful to gauge engine health and to assess how the equipment is utilized. Visibility of these aspects at locations remote from the site encourages the use of centralized staff resources that can apply their experience over the entire fleet instead of discrete units. ConocoPhillips' office staff do not have the benefit of viewing that data in Calgary.

Evolution of the design is a natural outcome of having more installations operating in the field. The latest development in Spartan's design is a modified exhaust bypass valve. The new design is more resistant to heat and more reliable. The previous version of this valve required constant attention. The newer version, which was tested in this project, is working reliably so far.

The cooling system for the engines on older units can also be problematic for units operating at full load. Coolers on older units were designed for lower ambient temperatures and some engines were equipped with low speed turbochargers. In this case, the cooling system required upgrades to the intercoolers, turbochargers and sometimes the aerial cooler.

One aspect that is most important is to obtain acceptance from field personnel. They must be comfortable with the technology since they have to make it work every day. Testimonials from trusted coworkers will be the best way to achieve a favorable recommendation. Knowledge of the system is also paramount in understanding what the system does. Unfortunately, most workers do not understand enough about how engines operate to grasp how the REMVue® AFR operates the engine.

For example, most workers visualize a rich burn configuration with a catalyst and a stepper valve for air-fuel control when an AFR system is mentioned. The lean conversion using a REMVue® AFR is nothing like that. This misconception has produced more resistance from field workers than any other aspect. Sometimes they simply have to gain personal experience with the system to see that it works.

The lean combustion process managed by the AFR system also maintains compliance with NOx emissions. The system does not employ an oxygen sensor to manage the combustion process. However, an oxygen sensor may be added for operator convenience if desired.

Finally, the pre-chambered spark plugs used in the first GL to GSI head conversion experienced a shorter than expected service life. The engine ran at higher head temperatures because the GL engine has a higher compression ratio than the GSI engine. Spartan developed a higher temperature version of their pre-chambered spark plug to address the shorter service life. This new, higher temperature design now forms their standard product. Further field testing at ConocoPhillips locations of the new design will continue.

REMVue® SlipStream®

Report Prepared by: Accurata, ConocoPhillips Canada, CETAC-WEST

Project Data Provided by: ConocoPhillips Canada

Introduction/Technology Description

SlipStream® is a proprietary technology developed by Spartan Controls as part of a suite of products comprising the REMVue® engine management and control systems. The technology works by employing vented emission streams to replace the primary fuel gas. The sources of the vented emissions are not normally at a pressure higher than the fuel gas system. A turbocharger must be in service on the engine in order to draw the gas into the system. The supplementary fuel source is introduced into the engine air intake duct just upstream of the turbocharger. A fuel meter determines the amount of primary fuel consumption offset by the supplementary fuel supply. The SlipStream® system is equipped with a dedicated PLC controller. It may be integrated into the REMVue® AFR system for supplementary fuel volumes up to 50% of the primary fuel consumption. The SlipStream® control system may be stand-alone for supplementary fuel volumes less than 10% of the primary fuel consumption.

SlipStream® Controller

Safety controls and devices are incorporated in the design to ensure the gas volume is not sufficient to be stoichiometric in the air duct. Purge sequences are incorporated into the start and stop cycles to ensure that no gas lingers in the air inlet duct on start-up when the likelihood of an intake combustion event is highest. Pressure relief devices are also incorporated at each source to ensure that the captured gas can be vented to the atmosphere rather than compromise the function of the venting system or the fuel systems. Individual vent valves restoring the gas vent to the atmosphere are also furnished at each vent source to restore the system to the original design when then SlipStream® is disabled.

SlipStream® Installation

The sources of vented gas may be obtained from tanks, packing vents, natural gas instrument vents and dehydrator still column vents. The vent collection systems must be individually designed at each site as several vent sources could be combined. Backpressure considerations are important for instrument gas vents and the maximum design pressure for the tanks in the collection system may be low. Also, tanks must be sealed so that air is not drawn into the system. The gas collection header system can become quite lengthy on some sites and must be considered from a pressure drop perspective. The quality of the vented gas as a fuel source and the amount of water vapor or inert gasses must also be considered during the design work.

Project Details

ConocoPhillips has installed five SlipStream® systems. The following vented emission sources were employed in these installations:

- Packing vents from compressors at several sites with multiple machines.
- Instrument vents on a natural gas instrument system.
- The still column vent from a dehydrator.

The expected vent rates can be reasonably predicted when the process is stable and known. That is the case for the still column vents on dehydrators. However, when the vent rates are based on condition assessments then the vent rates can be highly variable. An average vent rate that seems reasonable is then used for design. The volume of the supplementary fuel collected at each site will then be quite different from the estimates but it is hoped that the volumes average to the estimate over time. Figure 3 shows the dynamic response of the engine when the SlipStream® System stops supplying fuel flow.

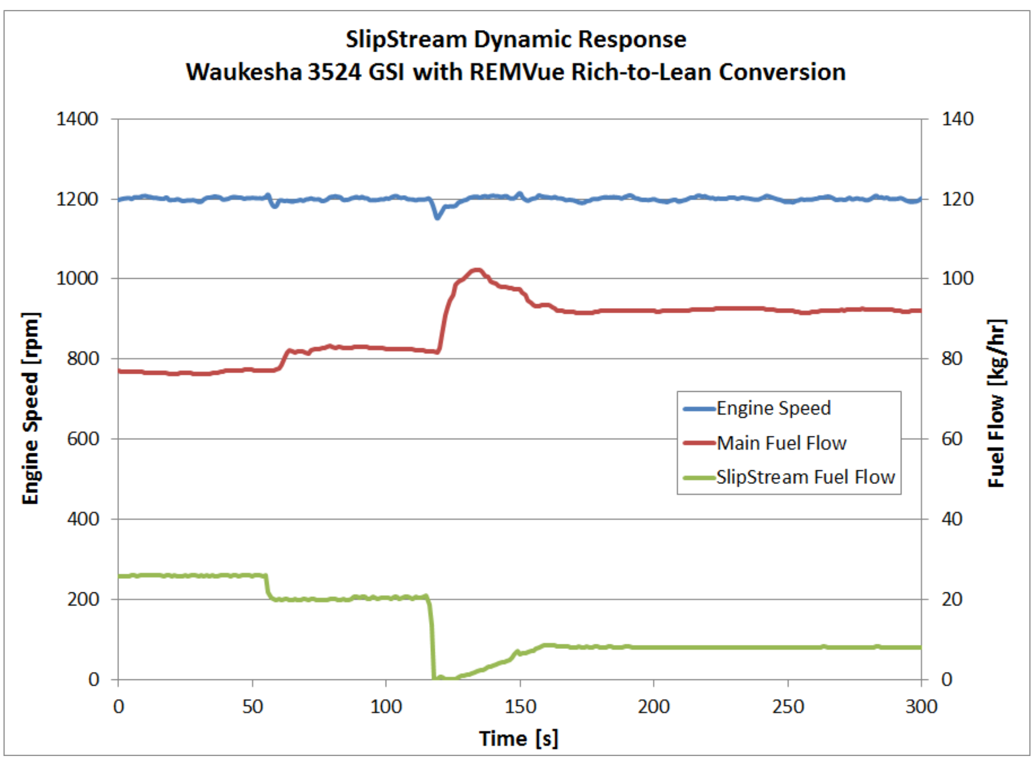


Figure 3. SlipStream® System Dynamic Response

Each site is evaluated to determine the possible vent sources and how they may be routed to an engine when they are captured. Experience with the equipment that is the source of vented emission as well as the engine that will accept the supplementary fuel is necessary to design a functional SlipStream® system. The equipment often contains unique design features that must be considered.

A site visit is required to assess the site, the equipment and its potential for a SlipStream® installation. Schematics may then be prepared for the installation. Suitable expertise is required in the design team to understand the risks and provide an economical design. Specialized skills and experience should be sought for the SlipStream® design and assessment. Spartan staff may be relied upon for expertise and experience but their focus is not on providing engineering design services.

ConocoPhillips utilized a common contractor on all sites when possible for the installations. Their construction coordinators and inspectors were also common to encourage repeatability and consistency. The uncertainty associated with the construction aspects can be significantly reduced if the installation crews are experienced with the product and how it is installed.

Results

GHG reductions will vary with the source and volume of vented gas. Cost recovery is achieved via replacement of primary fuel consumed which, in turn, may be sold as produced gas. The reduction of raw vented methane also provides a GHG reduction. Protocols for credits attributed to the GHG emission reductions are in place. Therefore additional cost recovery can be achieved via GHG credits.

The economics are evaluated for each site with its unique characteristics and blend of vent sources. SlipStream® installations can potentially have a cost recovery in two to four years depending on the natural gas rates, the value of GHG credits and the volume of supplementary fuel captured. The sensitivity of the economics to changes in GHG credit rates becomes more significant when natural gas prices are lower. However, primary fuel replacement will always provide cost recovery even if GHG credits are revoked.

The SlipStream® system sites also had REMVue® AFR systems installed. Therefore, the GHG reductions from the 5 SlipStream® installations also include the reductions from 25 REMVue® installations. Table 7 below shows the overall reductions of the projects.

Table 7. Overall REMVue and SlipStream Expectations and Results

	SAID	DID
Projects Completed	11	25 REMVue®+5 SlipStream®
Cumulative and Verified GHG Reductions up to Dec. 2015	n/a	40,146 tCO_2e
Potential GHG Reductions	7,811 tCO_2e/yr.	16,788 tCO_2e/yr.
Cost Abatement	\$4.98/ tCO_2e	\$21.50/ tCO_2e

"Golden Nuggets"/Project Takeaways

The quality of the vented gas must be suitable to burn in the engine when commingled with the primary fuel without damaging the engine. Where many of the vent sources are from the produced gas stream the fuel gas and vent gas streams are very similar and a change in engine service life would not be expected. ConocoPhillips captured the still column vents from a dehydrator and these are rich in benzene. Monitoring of the engine condition revealed that the introduction of the benzene into the engine fuel did not have any effect on the engine life. Using overheads from the plant processes might generate similar concerns and these should be evaluated by assessing a theoretical mix of the gas analysis from the primary fuel with the supplementary fuel source.

Pipe runs within the facility that are built on racks above grade will likely be more suitable for lower cost installations. Locating SlipStream® piping below grade adds significant cost to the piping installation unless a surplus pipe run is available. Normally piping of 2" diameter or less is adequate to convey the captured vent gases to the engine. The piping used for the vent capture is now subject to CSA B149.3 piping regulation compliance for fuel gas systems. That requirement was not in force at the time that ConocoPhillips' installations were being built.

The captured vent gas may be saturated with water vapour and at an elevated temperature. Running the gathering system piping on the pipe rack outside will allow the captured vent gas to cool and perhaps condense water or hydrocarbon vapours. The designer must decide if the piping should be insulated to prevent condensation. It is more economical to run uninsulated piping with drip legs to capture condensed liquids than it is to heat trace and insulate the SlipStream® vent capture piping. No freezing blockage of the SlipStream® vent collection piping was experienced at ConocoPhillips' sites as a result of using uninsulated exterior SlipStream® vent collection piping.

Estimates for the vent rates are always assembled prior to construction but these were rarely accurate. A common vent source that is relatively easy to collect is reciprocating compressor packing vents. The vent rates for the packing assemblies vary with time, pressure and wear. Many years ago, Encana workers measured a large sample of packing vent rates and determined a typical flow rate was 1.6 scfm (2.28 kg/h) per packing case. Since the packing vent rate is now being measured in the SlipStream® system then the condition of the packing assemblies is monitored where it was not otherwise. The packing cases are then serviced more frequently and the average vent rate is much less than expected, perhaps as low as ⅓ to ½ of the previous estimates. The small sample provided by ConocoPhillips' installations provided an average vent rate of 0.78 kg/h which is substantially less than the previous study predicted. However, as packing rings wear, the vent rate is expected to increase so the quantity of vented gas should increase over time.

The installation cost of vented gas capture was widely variable at ConocoPhillips' sites with an average of about $14,000 per kg/hr. The installation scope is significantly different between sites and the sample is small so the results may not be representative of future installations. Using a variety of contractors on the sites means that economies of scale had not yet been achieved to maximize construction efficiencies.

The existing packing vent and drain systems on reciprocating compressors often present design challenges. Small diameter tubing and vent systems are often in place that may not be adequate to convey the volume of gas produced by a catastrophic failure. The design team must decide what measures should be taken to modify the existing system or upgrade it. Since the existing system is normally designed by the original equipment manufacturer it is easy for workers to consider it safe. That is often not the case. Upgrading these assemblies introduces unexpected additional costs.

Leaks in the collection system may also reduce the volume of gas collected. This is especially true of instrument vent systems. Some of the pneumatic instruments require refurbishing to ensure seals are sound so that the vented gas is captured rather than leaked. Furthermore the collection system must be diligently inspected to ensure that no high pressure vents will affect the system performance. If the tanks in the system are sealed and a high flow vent is introduced, it may introduce pressure in the system that the operator is not expecting. This is especially true when considering procedures to evacuate or drain tanks connected to the SlipStream® system.

Obtaining acceptance for the systems is key to the success of the project. The SlipStream® system should be designed so that the operators do not have to change their regular routines to accommodate the operation of the gathering system. Time must be spent by the design team to review the plans for the system installation and operation with site personnel. Choosing project team members with sufficient experience to work with field personnel may help to establish credibility with field personnel and establish some confidence in the designs. Remote monitoring is also recommended so that office staff can ascertain if the SlipStream® system is functional. Expecting the system to provide revenue from GHG credits or fuel replacement cannot take place unless the system is operating. A manual data collection routine expects the field personnel to collect the data and submit it to the resources at head office that can convert the vented gas reduction into revenue. This approach is rarely successful and the opportunity to capitalize on part of the cost recovery portion is then lost.

Dehydration Optimization

Report Prepared by: Process Ecology, ConocoPhillips Canada, CETAC-WEST

Project Data Provided by: ConocoPhillips Canada

Introduction

The primary sources of GHG emissions in dehydration facilities include:

- Methane and CO_2 emissions in the flash tank and glycol regenerator still overheads.
- Energy exchange pumps.
- Stripping gas, used to improve dehydration efficiency.
- Regenerator burner (fuel gas combustion).

Dehydrators are a significant source of GHG emissions in the upstream oil and gas industry, and there is potential for industry-wide reduction through methodologies described in this paper. It is estimated that on average, dehydration facilities in Alberta circulate twice the required amount of glycol, and significant GHG emission reductions are possible through relatively simple and economic measures such as reduction of glycol circulation rate.

Project Details

The technologies described in Table 8 were demonstrated in this project. All technologies were commercially available and some technologies had been previously installed by ConocoPhillips (CPC) prior to this project.

Table 8. Technologies used in the project

Technology	Description
Dehydrator glycol pump electrification	Energy exchange pumps are replaced with electric pumps to reduce emissions from the pump while optimizing the glycol circulation rate.
Low pressure burner (Kenilworth)	Gas from the glycol reboiler stack is sent to a condenser to remove free liquids, then piped to a Kenilworth glycol reboiler burner system for use as the primary source of fuel, with header fuel gas as a back-up. In effect the reboiler acts as an incinerator.
Shell and tube heat exchanger (Jatco) & low pressure burner	Gas from the glycol reboiler stack is routed to the Jatco heat exchanger/condensing system. Uncondensed vapours are routed through a separation and filtering media to the main burner for fuel assist while the burner is operating. The Jatco in effect acts as an incinerator.

Flash tank tie-in	A glycol flash tank is installed to recover light hydrocarbons which are then routed to the fuel gas system.
Slipstream/dehydrator vent gas capture	Gas from the glycol reboiler stack is routed to a condenser; the uncondensed gas is then used as a supplementary fuel source for a compressor gas engine.
Energy Exchange pump circulation reduction	The circulation rate is reduced, directly reducing GHGs, while ensuring that gas is still being adequately dehydrated.

Two technologies stood out as having a widespread industry application to reduce fuel gas use and GHG emissions, in addition to other benefits such as benzene emission reduction:

1. The energy exchange glycol pump rate reductions clearly showed the greatest economic benefits, with very significant GHG savings.
2. The SlipStream® application successfully utilized vented gas as fuel to a compressor engine, with the benefit of removing most of the GHG and benzene emissions, and offering GHG reduction credits.

Both are good candidates for widespread industry adoption.

Dehydrator-SlipStream® Site

Results

The overall project expectations and results are shown below:

Table 9. Overall Dehydration Optimization Projects Expectations and Results

	SAID	DID
Projects Completed*	5	13
Cumulative and Verified GHG Reductions up to Dec. 2015	n/a	9,401 tCO_2e
Potential GHG Reductions	1,343 tCO_2e/yr.	5,278 tCO_2e/yr.
Cost Abatement	$16.76/$tCO_2e$	$4.8/$tCO_2e$

* Economics and savings for the glycol condenser SlipStream® project are not included in these totals, since they are included under the SlipStream® project.

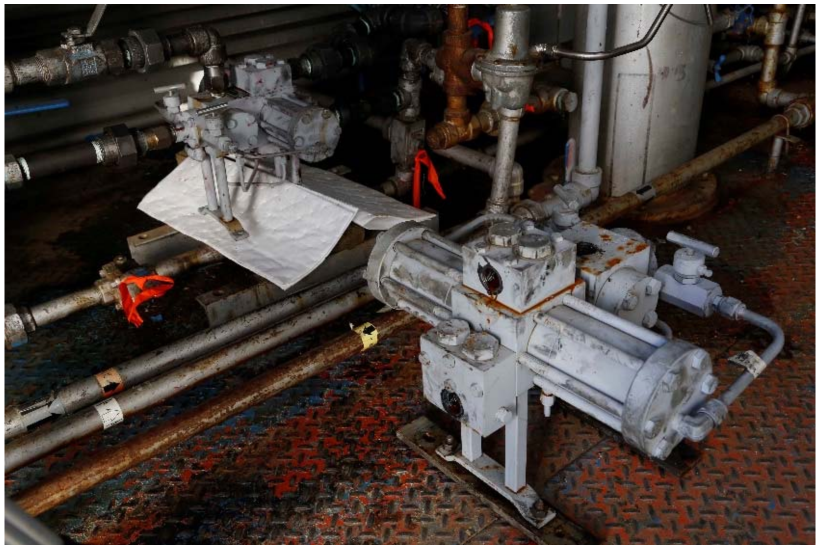
Table 10 provides details of the number of installations, costs and savings for each type of technology.

Table 10. Results for Each Specific Technology

Technology	Number of Installs	Approximate Cost per Install	Cumulative and Verified GHG Reductions Up to Dec 2015 (tCO_2e)	GHG Reductions (tCO_2e/yr.)
Dehydrator glycol pump electrification	1	$87,354	490	123
Low pressure burner (Kenilworth)	2	$72,500	4,907	1185
Shell and tube heat exchanger (Jatco) & burner	1	$196,300	1954	651
Flash tank tie-in	1	$21,000	348	116
Energy Exchange pump circulation reduction	8	$7,966	1700	3202

GHG and Fuel Gas Measurements

With the exception of the SlipStream® technology, fuel gas and GHG reductions were calculated based on process simulation results. Fuel gas savings resulting from reducing the pump speed to optimize the circulation rate were made using the manufacturers' fuel consumption data for pressure and circulation rate. The circulation rate from which the loss of methane is calculated was determined by counting the strokes of the energy exchange pumps and manufacturers' data for electric powered pumps. The burner fuel gas was estimated assuming 60% combustion efficiency, using the simulator-predicted reboiler duty.



Pump Circulation Reduction

The Slipstream technology was installed with mass flow meters that could accurately measure the vented gas and correlate it to the associated GHG reductions and fuel gas reductions. The composition of the gas was also measured, so that the corresponding amount of GHG gasses could be determined.

Table 11 shows an example of the calculation for reduction of circulation rate of an energy exchange pump, resulting in a total reduction of 933 t/CO_2e per year.

Table 11. Energy Exchange Pump Reduction Example

Circulation Rate Optimization	As-found	Optimized
Circulation (US gpm)	1.33	0.68
CO2E Emitted (tCO_2e/yr.)	1,988	1,121
Burner (tCO_2e/yr.)	133	67
Total (tCO_2e/yr.)	2,121	1,188

"Golden Nuggets"/Project Takeaways

Dehydrator recirculation pump electrification

- This can be applied when there is an existing energy exchange pump (Kimray), and where electric power is available.
- There can potentially be a significant reduction in GHGs, due to the ultimate venting of high pressure gas used to power the energy exchange pump, which can be eliminated.
- Many additional modifications were required, including contactor level control and, at operations request, instrumentation to control a back-up energy exchange pump, which added to the operating complexity.
- This proved to be an expensive option.

Dehydrator recirculation pump

Low Pressure Burners

- The Kenilworth systems were not the correct choice for systems with energy exchange pumps because these pumps generated more gas to be burned than the burner requires to regenerate the glycol.
- The Jatco system provided an engineered heat exchanger; in this case, combined with an Eclipse burner, it proved to be effective.
- There were challenges with the low pressure burner and condensation of recovered gas. The gas recovered from the condenser overhead was not always a reliable source of secondary fuel, so operations would bypass the system in cold weather.
- It was necessary to ensure that the piping was correctly sloped such that condensed (and possibly burnable) liquids would flow back to the condenser, rather than to the burner.
- These systems would be more economic at larger facilities.

Flash Tank tie-in

- Where there is no glycol flash tank, this option can be used to recover vapours that can then be introduced to the fuel gas system or flare header. Otherwise these vapours are vented from the still.
- Alternatively, where a glycol flash tank exists, but the flash overhead is not recovered (e.g. sent to flare), it can be economic to recover the flash vapour and route it to the fuel gas system.
- This can potentially be an economically viable option, depending on factors such as size of facility and existing configuration.

- New facilities should employ flash tanks to recover the light hydrocarbons.

Still overheads to SlipStream®

- For this option, there needs to be a condenser (e.g., TankSafe) in place, as well as proximity to a compressor engine.
- For CPC, this was a successful option, reliably providing significant GHG reduction.
- Where stripping gas is needed to ensure sufficient dehydration, SlipStream® effectively recovers this gas.
- This system works very well to reduce GHG emissions, reduce fuel gas use and increase production while removing virtually all benzene and other hydrocarbon emissions from the dehydrator.

Energy Exchange pump rate reduction

- Pump rate reduction can be employed at facilities that are over-circulating glycol (the majority of dehydration facilities may be over-circulating). Depending on the pump characteristics, in some cases, the circulation rate can be turned down, while in others, pump replacement would be needed.
- It is necessary to ensure that the contactor performs adequately at low rates.
- There is also an opportunity to turn down electric pumps, although the GHG benefit is not as significant as for energy exchange pumps.

In all cases, operator buy-in is critical to ensure that they understand and trust the proposed modifications, with a better chance of ensuring long-term success.

The biggest opportunities for GHG reduction come with facilities that are emitting a large amount of methane from the still overhead. Factors contributing to this condition include:

- Use of energy exchange pump with no flash tank.
- Use of stripping gas.
- Still overhead venting to atmosphere.
- Large glycol circulation rate.

While not considered a “project” for this study, reduction or elimination of stripping gas is considered to be a significant and inexpensive way to reduce GHG emissions in dehydration facilities.

Waste Heat Recovery

Report Prepared by: Sulphur Experts, ConocoPhillips Canada, CETAC-WEST

Project Data Provided by: ConocoPhillips Canada

Introduction/Technology Description

Natural gas engines reject about 70% of the input energy as heat in the exhaust gas and the cooling jacket. Exhaust gas temperatures are typically close to 120^{O}C while the cooling jacket temperature reject stream may be between 70^{O}C and 100^{O}C. There are numerous process heat sinks that operate at or below these temperatures and may be considered as candidates for heat recovery with a corresponding reduction in fuel gas inputs.

The technology required for heat recovery can be the tried-and-true shell and tube exchangers as well as the more exotic heat pipes. In spite of the obvious amount of energy that is lost from gas engines, this energy is of low grade and the resulting small temperature differential between the heat source and sink has a significant impact on the amount of energy (or efficiency of the cycle) that can be obtained. This is a characteristic of low and medium grade energy sources. As a result, finding good fits between reject heat and heat sinks proved to be the single greatest challenge in this project. A further unanticipated challenge was the need to design and fabricate pressure vessels when attempting to recover higher grade energy (> 121^{O}C).

A successful outcome for the project was deemed to be proof that reject heat from a commonly employed gas driven reciprocating engine could provide heat to process users and thereby reduce fuel gas consumption.

The initial scope of this project was to undertake a total of 14 installations with an estimated budget of $4,912K, fuel gas savings of 5,492 e^3m^3/yr. and GHG reductions of 11,079 tCO_2e/year. The final project had 7 installations with a total cost of about $1,203,000, estimated fuel gas savings are 1,000 e^3m^3 and GHG reductions of 2,000 tCO_2e/year.

The first installation involving a heat pipe installed in the engine exhaust stream proved to be far more complicated than expected and raised a number of doubts as to the viability of the overall project. This led to a change in focus from large scale high temperature opportunities to small scale lower temperature applications. It is therefore appropriate to consider this project as having two phases: Phase 1 being the heat pipe, high temperature exhaust gas installation and Phase 2 being the several small scale cooling jacket installations. The low cost options that evolved included the direct use of cooling jacket fluid for heat tracing using the cooling jacket pump developed by Heat Hawg Inc. This vendor-developed system extracts exhaust heat for heat tracing and conventional shell and tube exchangers to capture cooling jacket heat for tracing systems.

PHASE 1

ConocoPhillips had expected to demonstrate the robustness of heat recovery by undertaking nine installations. For simplicity, the first of these was a single engine installation even though multiple engine arrangements were available. The recovered energy would be utilized to heat the incoming fluid to a conventional hot oil heater. In order to maximize the quantity of energy that could be recovered from the exhaust gas, a heat pipe was selected as the technology of choice, in spite of the limited use of this technology in Alberta.

Technology Description

A heat pipe is a heat-transfer device that combines the principles of both thermal conductivity and phase transition to efficiently manage the transfer of heat between two solid interfaces.

As can be seen in Figure 4, at the hot interface of a heat pipe, a liquid in contact with a thermally conductive solid surface turns into a vapor by absorbing heat from that surface. The vapor then travels along the heat pipe to the cold interface and condenses back into a liquid - releasing the latent heat. The liquid then returns to the hot interface through capillary action, centrifugal force, or gravity, and the cycle repeats. Due to the very high heat transfer coefficients for boiling and condensation, heat pipes are highly effective thermal conductors.

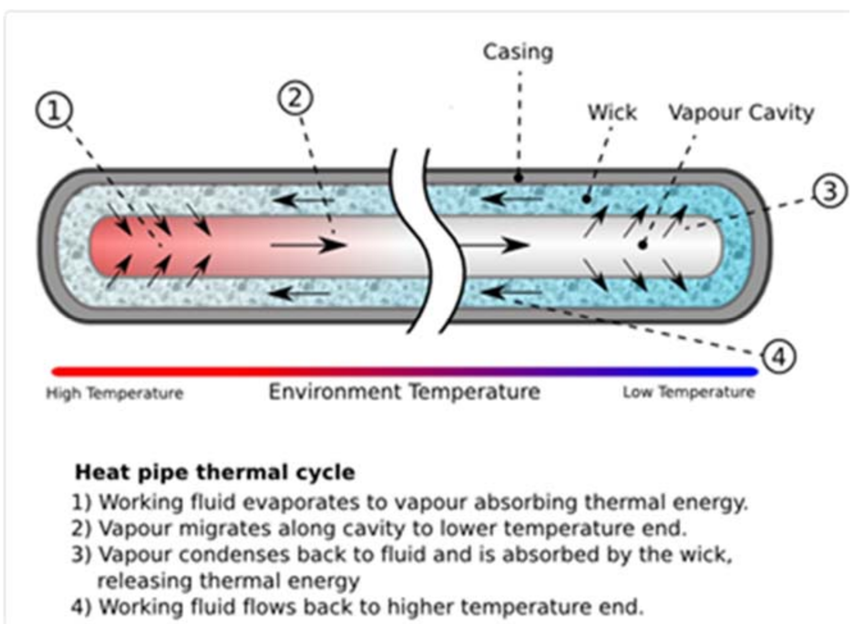


Figure 4. Heat Pipe Process Description

When one end of the heat pipe is heated, the working fluid inside the pipe at that end evaporates and increases the vapor pressure inside the cavity of the heat pipe. The latent heat of evaporation absorbed by the vaporization of the working fluid reduces the temperature at the hot end of the pipe. The vapor pressure over the hot liquid working fluid at the hot end of the pipe is higher than the equilibrium vapor pressure over the condensing working fluid at the cooler end of the pipe, and this pressure difference drives a rapid mass transfer to the condensing end where the excess vapor condenses, releases its latent heat, and warms the cool end of the pipe. The condensed working fluid then flows back to the hot end of the pipe. In the case of vertically oriented heat pipes the fluid may be moved by the force of gravity. In the case of heat pipes containing wicks, the fluid is returned by capillary action.

Heat pipes contain no mechanical moving parts but the eventual breakdown of the working fluid or deposition of impurities extant in the material, may eventually reduce the pipe's effectiveness at transferring heat.

"Golden Nuggets"/Project Takeaways

- **Heat pipe orientation**

Orientation is fixed by the design and construction of an individual heat pipe. Due to a lack of communication between the vendor and ConocoPhillips (CPC), the required orientation of the heat pipe was overlooked at the installation stage and led to significant rework on the installation.

- **ABSA code requirements and temperature limits**

ABSA requires exchangers operating at 121°C and higher to be registered as pressure vessels. This required extra design work and certification. Most pressurized glycol systems in Alberta are built to ASME B31.3 to overcome this limitation.

- **Exhaust gas service**

Installing heat exchangers in the exhaust stream of a reciprocating engine exposes this equipment to considerable vibration and this resulted in a premature failure of the heat exchanger.

- **Spatial considerations**

Long runs of pipe between the heat source and heat sink and additional pumping costs can have a significant impact on project economics. Additionally, problems fitting all equipment into the available small space necessitated modifications to be made at site during install.

- **Understanding the technology**

As the project progressed it became apparent that both CPC staff and ABSA staff were not fully conversant with heat pipe technology and, in the absence of local vendor support, lengthy delays were incurred.

- **Reciprocating engine exhausts**

Exhaust piping configurations vary considerably at reciprocating compressor installations. For projects where a waste-heat-exchanger (WHE) is to be retrofitted into this existing exhaust stream, it's important to understand the maximum allowable dimensions and the necessary WHE configuration in order to fit the WHE into the existing system without design iterations and/or rework. It is also necessary to accommodate the considerable vibration.

- **Canadian Requirements for components purchased outside of Canada:**

CRN/ABSA – Refabricating pipe spools in shop/registering pressure vessels.

- **GHG Protocol**

Identifying the right instrumentation and measurement needed for GHG credits was challenging since this was the first WHE on behalf of CCEMC. In order to estimate the GHG reduction, a calculation of the heat recovered is made by taking the flow of the working fluid and the temperature difference between the inlet and outlet of the fluid at the exchange point. The fuel gas savings are then calculated using an assumed or measured efficiency of the existing heating source (typically a fired heater).

Cooling Jacket Fluid for Heat Tracing

PHASE 2

As a result of the difficulties and poor project economics experienced in Phase 1, the “opportunity” focus shifted from large-engine exhaust heat recovery to small-engine jacket water heat recovery and small scale engine exhaust gas applications. This lower grade energy source is adequate to use in heat tracing of surface piping (freeze protection). Applications included direct use of cooling jacket fluid for heat tracing, an external heat exchanger to recover heat from cooling jacket fluids in four (4) applications, and installation of two “Heat Hawg” units on the engine exhausts to capture heat and pump glycol through heat tracing.

“Golden Nuggets”/Project Takeaways

- **Jacket water exchangers**
  Heat exchangers are often not required but if they are utilized they are smaller and less expensive due to better thermal transfer from a liquid vs. gas phase.

- **Pumping**
  Jacket water heat trace can often be accomplished by utilizing the existing jacket water pump.

- **Glycol Dehydration Systems**
  Glycol regeneration for dehydration projects are not economic because the flow rates and heat load are not high enough for the fuel gas savings to pay for the capital costs.

- **Personnel**
  Time and costs can be reduced by using the same facilities engineer and the same inspectors for small projects.

Results

The overall project expectations and results are shown in Table 12 below:

Table 12. Overall Results from the Waste Heat Recovery Projects

	SAID	DID
Projects Completed	14	7
Expected Yearly GHG Reductions	11,079 tCO_2e/yr.	2,157 tCO_2e/yr.
Cost Abatement	$19.62	$27.90

Waste Heat to Electricity

Report Prepared by: Sulphur Experts, ConocoPhillips Canada, CETAC-WEST

Project Data Provided by: ConocoPhillips Canada

Introduction/Technology Description

Figure 5 below shows the basic elements of the Organic Rankine Cycle (ORC) installation.

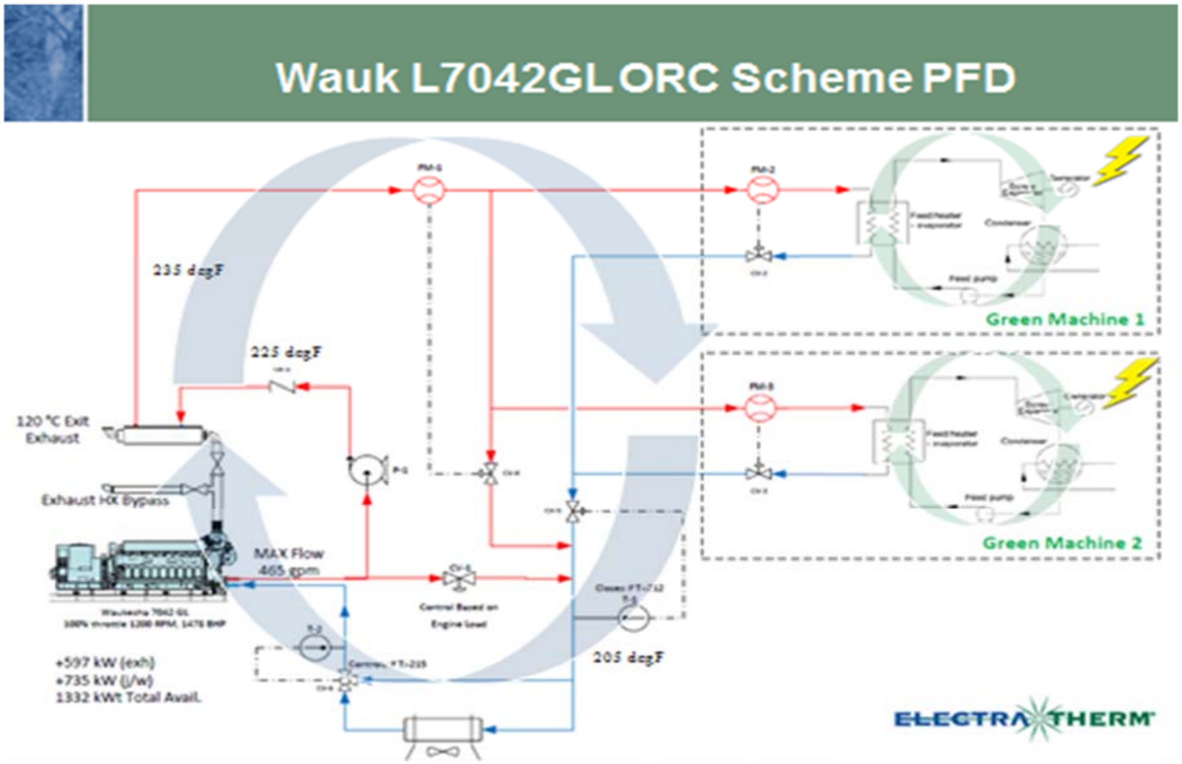


Figure 5. Elements of an Organic Ranking Cycle Installation

The high temperature source (cooling jacket and exhaust gas) is used to evaporate an organic fluid which is then expanded across a turbine that drives a generator. The low pressure vapor is then condensed in an aerial cooler and pumped back to the evaporator.

The intent of this project was not to prove that ORC technology works; there is adequate evidence of this but there has not been extensive use of this technology on small scale low grade waste heat applications. Rather, the objective of this project was to determine if commercially available and proven components of an appropriate- size could be selected, purchased and assembled with minimal engineering and development effort. This was done with the full understanding that the final installation may not have the highest possible efficiency but would have the advantage of short project timelines and a high degree of confidence in the outcome.
A successful outcome for the project was deemed to be proof that reject heat from a commonly employed gas driven reciprocating engine could reliably generate useful amounts of electricity.

The project was a technical success and provided valuable learnings for ConocoPhillips and the Alberta oil and gas industry in general. From an economic perspective, this project showed that waste heat to power at this level is difficult to justify economically but may be applicable if electricity was required but not available at a remote location.

Project Details

In order to simplify the project, a single engine installation was chosen even though multiple engine arrangements were available. The components that were selected and the rationale for this are provided below:

- Waukesha L7042GL engine with a rated capacity of 1100kW. This is a very common engine in the ConocoPhillips fleet and throughout the upstream natural gas field.
- Heat recovery from the engine water jacket with exhaust gas temperature boost.
- Aprovis conventional shell/tube exhaust gas heat exchanger with built-in bypass. Simplicity was deemed to be of higher importance than size and efficiency.
- Two (2) ElectraTherm 50-75kW Green Machine ORC skids. Using two parallel units was necessitated by the desire to use shelf-ready proven systems rather than a custom design for this application.
- Two (2) Guntner air-cooled condensers to adhere to the philosophy of proven and readily available components.
- Honeywell R245fa refrigerant non-flammable, non-toxic, non-ozone depleting.
- Containerization - robust mobility all components to be assembled and shipped in 20’ shipping containers.

Results

The overall project expectations and results are shown below:

Table 13. Overall Results from Waste Heat to Electricity Project

	SAID	DID
Projects Completed	1	1
Expected Yearly GHG Reductions	2,135 tCO_2e/yr.	266 tCO_2e/yr.
Cost Abatement	\$26.35/tCO_2e	\$351.7/tCO_2e

“Golden Nuggets”/Project Takeaways

In spite of the fact that significant effort was made to employ commercially proven technology, this project did experience a number of unforeseen circumstances that are identified below:

Canadian Requirements for components purchased outside of Canada:

- CRN/ABSA – Necessitated refabricating pipe spools in shop/registering pressure vessels.

- CSA Electrical – Relocating panels & rewiring skids in field.

Control System Complexity

- The use of two ORC skids from a single thermal loop required a control system that could properly manage the flow-splitting of engine jacket water (EJW).

Site Specific Impediments

- Electrical system location and vintage resulted in overly long cable runs from the generator to the Motor Control Centre (MCC) which lacked suitable cubicles.

- Engine Suitability
  The specific engine exhibited what might be described as old age as evident by engine start difficulties, heating and health.

- Site Electrical Stability
  Disturbances on the electrical grid resulted in system trips.

- Adapting digital age electrical protection system to the existing relay based system.

Exhaust Gas Exchanger Backfire Pressure Protection

- An engine backfire incident resulted in damage to the exhaust gas heat exchanger and required changes to be made to prevent this type of occurrence.

Communications Interfaces

- The need to integrate the new system controls with the existing engine protection schemes was hampered by ConocoPhillips’ IT protocols, firewalls, and age of components.

While all of the above issues were successfully overcome, the project duration was impacted and, in the case of the engine backfire issue, a heat exchanger had to be replaced. It is estimated that the above discussed issues increased the installation cost by some $125,000; this might be typical of brownfield installations in general. The lack of locally available technology is expected to be a significant impediment for this type of project and is unlikely to be overcome in the near term. In many aspects this is typical for new technology adaptation; vendors don’t see sufficient demand and customers don’t see proven performance.

Waste Pressure Recovery

Report Prepared by: Accurata, ConocoPhillips Canada, CETAC-WEST

Project Data Provided by: ConocoPhillips Canada

Introduction

Waste pressure recovery is attractive because most gathering systems are arranged to build pressure for transport of the fluid and then reduce the pressure to permit a controlled delivery to the consumer. If some method of harnessing work can be derived from the pressure let-down, then that may be applied to driving some other equipment or generating power. The oil and gas processing and transportation industries provide many waste pressure opportunities. Pressure reduction of liquid allows for more effective means of harnessing energy than gas because the higher fluid viscosity permits more effective energy transfer. Pressure reduction in gas systems also carries the possibility of forming liquids or freezing during super-cooling.

Several pressure drop to power options were evaluated. The most common option was pressure let down from pipeline to lower distribution system elements. These installations typically require high flow rates and large pressure differentials. Furthermore, the scale of the equipment is normally quite large and expensive. They are more suitable for locations closer to the delivery of the gas to the final consumer. As such, typical upstream companies will not have a suitable location for these installations.

The final site selection utilized pressure drop in an amine process to drive a generator. The generator would produce power for local plant consumption and replace power purchased from the utility. Due to difficulties in obtaining interest from suppliers, as well as the high costs in changes to piping and wiring in the existing plant, the emphasis of the project changed from producing electricity to directly driving a high pressure pump. However, in the current economic climate this technology proved to be uneconomical and did not proceed. The budget was reallocated to more cost effective technologies in the overall project. However, the project did produce benefits in its evaluation of several types of equipment. If power prices increase in the future this technology may become viable.

Project Details

The pressure drop is harnessed from the rich amine stream in the process between the absorber and the regenerator. This pressure drop is used to spin a turbine that drives a pump to replace a portion of the duty for the high pressure pump that conveys the lean amine back into the absorber. Less power is then required to drive a smaller pump in the process for the lean amine. A pressure drop of 650 psi at 450 GPM was expected to save about 170 kW (110 kW from the turbine driven pump and 60 kW from reducing the booster pump size). A system called ISOboost from a company called Energy Recovery is available as a fit-for-purpose solution. The system is a variety of HPRT (Hydraulic Power Recovery Turbine).

The goal of this technology project was to harness a pressure drop to generate power or drive some other piece of equipment. The initial objective was to complete one application with a GHG reduction of 924 tCO_2e/year and to evaluate the economics of this small scale pressure recovery system.

ConocoPhillips had planned to install one system. However, it found that high costs would have been incurred for piping and wiring changes at the existing ConocoPhillips gas plants. The money allocated for that system was therefore reallocated to other CCEMC projects once the waste pressure recovery project was cancelled.

ConocoPhillips staff examined other installations to provide background on what is working and what lessons could be learned from their operators. Two other installations are currently available in Alberta. The Quirk Creek Gas Plant (Pengrowth) has a high pressure recovery turbine installed. A recent plant turndown has shut this turbine down. The Caroline Gas Plant (Shell) has installed a waste pressure to power system which remains operational. ConocoPhillips did not have a suitable location for this type of installation.

Results

Two or three design configurations were examined which provided between five and fifteen years to achieve cost recovery. The implementation of this equipment requires a large plant to be viable. Budget cuts in a depressed commodity market decreased capital availability. Electricity rates falling by more than 30% to 4.4 ₵/kW-h made the project uneconomical.

GHG reductions would have been available from the savings in produced electrical power. A protocol for GHG credits is in place for offsetting electrical power. The economics would be obtained from purchased electrical power savings and GHG credits.

“Golden Nuggets”/Project Takeaways

Most waste pressure drop to power options are designed for large flow rates and high pressure differentials (approximately 7 to 15 MMSCFD flow and 1,000 to 2,000 psig pressure drop). The installations are meant for large scale power generation where a utility takes the high pressure pipeline gas and lowers the pressure into their distribution system. Thus the scale of the equipment is quite large. These applications do not exist in the upstream oil and gas industry.

ConocoPhillips examined one possible site and determined that the technology would cost $1.8 million Euros plus the design and installation costs. It consisted of a turboexpander similar to a cryogenic processes used for liquids extraction in the upstream oil and gas industry. That type of equipment is complicated with long lead times. This alternative did not fit for budget or timeframe in their CCEMC projects.

The biggest issue in the upstream oil and gas sector for pressure drop to power projects is that pressure drop is not desirable in the processing systems. Adding pressure drop to a well decreases production. Lowering pressure in the system eventually requires more compression to recover that pressure so then compression horsepower is wasted. Pressure drops that are tolerated are normally 35–70 kPag (5–10 psig) for larger flows in process components or smaller flows with perhaps as much as 700 kPag (100 psig) across a fuel gas regulator.

The HPRT waste pressure recovery technology is more sensitive to budget cycles because the capital cost is high. Retrofit costs are high because the existing piping and electrical installations require modification which might not be feasible within the constraints of the space available. A case for shutting in the equipment to install the necessary modifications incurs significant costs associated with lost production which make the project less viable. Replacing the existing equipment on the occasion of a failure might present an opportunity to incorporate waste pressure recovery technology if the required equipment was at hand. The waste pressure recovery technology would be applicable to sour gas plants which number less than 200 in Alberta.

Implementing the equipment changes in a new facility would present fewer challenges in construction constraints or in the additional capital required. ConocoPhillips found that vendors of equipment such as pumps and gears were not interested in the technology. It should be noted that many of the equipment choices require a specific direction of rotation to drive oil pump and ancillary systems. Harnessing a pressure drop would require running the equipment in a reverse rotation which would require substantial reconfiguration for most equipment choices. Therefore equipment choices are limited and lead times can exceed one year.

The ISOboost technology would benefit new installations. A new design could be tailored to the technology in order to reduce the installation costs. The economic benefit would be more easily achieved in that circumstance.

High to Low/No Bleed Conversions

Report Prepared by: GreenPath Energy, ConocoPhillips Canada, CETAC-WEST

Project Data Provided by: ConocoPhillips Canada

Introduction/Technology Description

Upstream oil and gas facilities often rely upon pressurized methane fuel gas as a motive source for pneumatic devices for process control. These devices generally vent methane fuel gas to atmosphere at a steady state (static consumption) in addition to when the controller is actuating (dynamic consumption). The US EPA defines low bleed pneumatic controllers as controllers with a static gas consumption of less than 6 standard cubic per hour (scfh) or $0.17 m^3/hr$.

The project began with the objective of retrofitting Fisher 4150 pressure controllers with the Mizer® retrofit kit which is designed to convert high bleed instruments to low bleed instruments. ConocoPhillips installed a small number of Mizer® retrofit kits. While the Mizer® retrofit demonstrated the ability to convert high bleed pressure controllers to low bleed status, operators were uncomfortable working with these Mizer® equipped controllers due to the fact that these retrofitted devices acted erratically when tight pressure set point control was required (i.e. compressor inlet pressure control). The Mizer® might be the right tool, but only in certain circumstances where process stream and desired tuning parameters will allow.

Fisher Controller

Focus was then on the following replacements and removals:

- The replacement of the Fisher 546 Electro-pneumatic transducer with the newer low bleed Fisher i2P-100 equivalent model.
- Retrofitting Fisher i2P-100 with a retrofit restrictor plate kit to reduce static consumption below 6 standard cubic feet per hour (scfh) 0.17m3/hr).
- Replacing Fisher 4150 Pressure controllers with the Fisher C1 equivalent.
- Retiring Fisher 4150 and equivalent pressure control models from operation where they were no longer required. After the fields had delineated, throttling pressure control was no longer required; thus the pressure controllers could be removed without any adverse effect on production and operations.

Project Details

Table 14 gives details of the number and type of high to low bleed replacements and removals.

Table 14. Types of Projects Completed

High Bleed Device Make / Model	Low Bleed Device Make / Model	GHG Reduction Driver	Approximate Number of Pneumatic Devices
Fisher 4150	n/a	Removal	39
Fisher 546	Fisher i2P-100 low bleed	Replacement	357
Fisher i2P-100 high bleed	Fisher i2P-100 low bleed	Retrofit	206
Fisher/CVS 4150	Fisher C1	Replacement	302
Fisher/CVS 4150	Mizer Kit	Retrofit	3
N/A	AMOT Valve	Installation	10
Fuel Gas	Compressed Air	Retrofit	37
Pneumatic Actuator	Rotork Electric Actuator	Replacement	1
Level Controller	Low or No Bleed Level Controller	Replacement	33

Current installation practice includes:

- One-man team, with operator on site during conversion.
- 3-5 installations per day depending on well-spacing.
- Well shut in for an average 30 minutes during conversion process. Shut in not necessary in all cases.
- Typically no net loss in production due to shut in time.

Current manpower practice for low bleed pneumatic device conversions and or retrofits consists of a one-man team. However, prior to utilizing the one-man team structure, a two-man team plus well site operator were formed to complete work in the Wapiti field. The well site operator role was to manage the well site and not the installation controllers. The crews managed between 3-5 installations per day. The key variable in determining how many conversions could be performed was the distance between wells and co-ordination with the operator. The actual time for the well shut in was as little as 30 minutes. Given the excess capacity in the system, this lost 30 minutes of production was rapidly made up when the well came online again.

Results

The overall project expectations and results are shown in Table 15 below:

Table 15. Overall Results from High to Low Bleed Conversions

	SAID	DID
Projects Completed	200	988
Cumulative and Verified GHG Reductions up to Dec. 2015	n/a	71,075 tCO_2e
Expected Yearly GHG Reductions	5,300 tCO_2e/yr.	62,551 tCO_2e/yr.
Cost Abatement	\$5.66/tCO_2e	\$1.30/tCO_2e

"Golden Nuggets"/Project Takeaways

Most of the conversions have been from standard old model pneumatic instruments to low bleed instruments used to control gas well flow rate. In most cases, flow rates have decreased and the valve could be 100% open all the time. In these cases the controller could simply be removed.

The most effective implementation approach was found to be first securing field level buy-in to ensure seamless on-site activities and financing of projects from maintenance/operating budgets. This resulted in a significant reduction in project management time and expense savings as retrofits could be executed without the need to raise an AFE. It was also found most cost effective to pre-order a significant quantity of instruments and store them in a warehouse for later installation by an instrument company and an operator. Typically 5 to 7 instruments could be installed in one day.

In terms of installation learnings, it was found that having installation crews equipped with surplus installation material (Teck cable, SST tubing, fitting, etc.) saved time since there were variances in well site construction configurations. If the crews had the appropriate stock on hand, it allowed for faster implementations at multiple sites without returning to base for supplies.

Another key lesson in this project was realizing the need for a pneumatic inventory upon which to base the retrofit decisions. Time was lost in the field initially trying to determine which controllers to order for the sites.

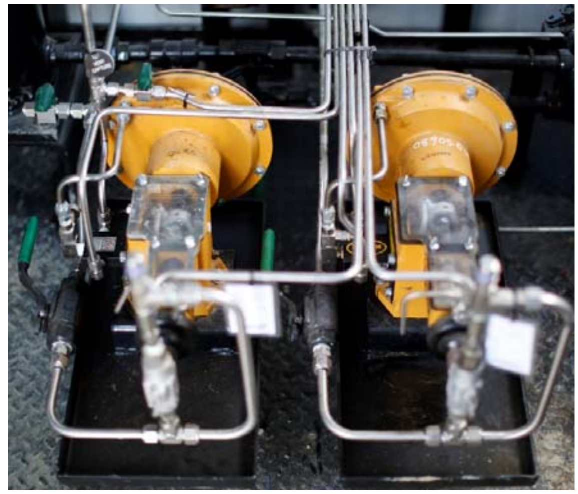
Snap acting level controllers are not supposed to bleed gas, but they all bled continuously. This may result in a shift to the solar well site conversion as the only solution to reduce this venting is the installation of electric controls.

Solar Chemical Injection Pumps

Report Prepared by: GreenPath Energy, ConocoPhillips Canada, CETAC-WEST

Project Data Provided by: ConocoPhillips Canada

Introduction


Pneumatic Chemical Injection Pumps

In upstream oil and gas operations the injection of relatively small amounts of chemicals to enable processing and production is commonly accomplished by utilizing positive displacement piston or diaphragm actuated pumps. These pumps leverage readily available pressurized fuel gas as the motive force in order to inject chemicals into pressurized process streams. A typical well site has one or two pumps and one or two chemical injection pumps. All of these devices vent natural gas to the atmosphere.

Solar Chemical Injection Pumps(SCP) chosen for this project were very successful and well received by operations. The sites selected for SCP installations have largely been driven by requests from the field personnel, as opposed to push from CPC head office, once momentum was built on earlier SCP installations. Operations personnel were more skeptical of the performance of an SCP at higher latitudes, especially when wells were in valleys and sunlight was more limited.

Project Details

The original CCEMC application called for the installation of 50 SCP packages across CPC's asset base. To date, CPC has installed 86 SCP packages, with installations concentrated in the operating areas of Clearwater, Cessford and Hanna. Almost all of the SCP installations have been retrofits of pneumatic pumps as opposed to greenfield installations.

Solar Chemical Injection Pumps

In addition, two "zero emission" wellsite configurations have been installed with CCEMC funding. The majority of the reductions from this technology type come from replacing a gas driven pump with a solar chemical pump. However, there is also a reduction via replacement of Fisher2500 level controller with electrically actuated valves. Emissions from shutdown valves (which are now electric) have been excluded from the analysis.

Results

Overall results for the project are shown in Table 16 below:

Table 16. Overall Results from Solar Chemical Pump Conversion Projects

	SAID	DID
Projects Completed	50	85
Cumulative and Verified GHG Reductions up to Dec. 2015	n/a	6,615 tCO_2e
Expected Yearly GHG Reductions	6,183 tCO_2e/yr.	5,698 tCO_2e/yr.
Cost Abatement	\$6.07/tCO_2e	\$10.70/tCO_2e

The SCP project economics are radically altered via the carbon price placed upon otherwise vented methane due to the 25 times global warming potential of CH_4 relative to CO_2 in the atmosphere.

Currently there is not an approved protocol for the quantification of emissions reductions from the use of SCP in greenfield and retrofit cases. Cap-Op Energy Inc. has put forth a Technical Seed Document (TSD) before the Alberta Government to modify the existing Instrument Gas to Instrument Air for Process Control Carbon Offset Quantification Protocol (Instrument Air Protocol) to include emissions reductions from converting gas driven pumps to solar chemical pumps. The more accurate injected volumes of chemical from a solar chemical pump may make statistical sampling more accurate than the previously proposed quantification method, which relied upon tracking injected liquid volumes to back-solve for natural gas vented in the baseline condition.

“Golden Nuggets”/Project Takeaways

- Sirius Controls supplied the technology package comprising solar panels, back up batteries, zero leak chemical pumps and storage tanks. The site location, injection rates and injection pressures were provided for system design, assembly and shipment to the required location. Installation was easy requiring only connection to the chemical injection port.

- The Sirius technology has been very well received by the field staff and so far reliability has been good. Solar pump solutions were introduced in Canada in the mid to late 2000’s did not perform as well, due to solar panels and batteries not being sized for Canadian geography (less light requires more panels and a different position, cold weather requires batteries in an insulated enclosure). The Sirius systems have been performing well to date.

- The electric powered pump enabled very precise chemical injection compared to the replaced gas powered pumps. Savings of expensive chemicals such as corrosion inhibitors were significant.

- The system worked best on wells that have declined in production, due to lower injection pressures, but sometimes was installed on new wells.

- In a similar fashion to the high to low bleed conversions, it was found best to pre-order and warehouse the well site conversions for ease of installation and for discounts on larger orders.

- The technology has worked well to date at all locations which have been in the Grande Prairie area. The location determines the number of solar panels and back up batteries required and the economics clearly favour more southerly locations.

Solar Chemical Pump Installation

Vent Gas Capture

Report Prepared by: GreenPath Energy, ConocoPhillips Canada, CETAC-WEST

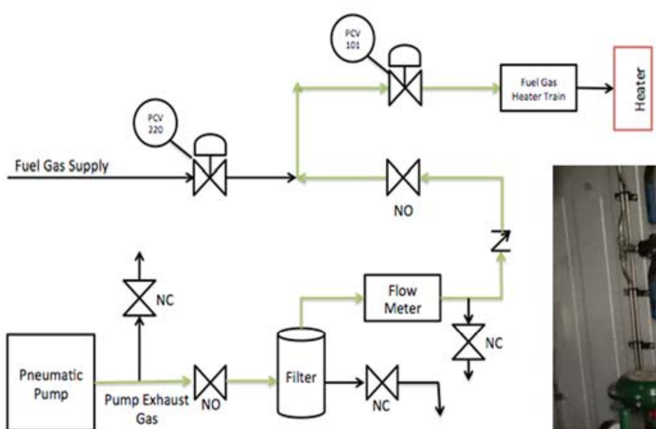
Project Data Provided by: ConocoPhillips Canada

Introduction/Technology Description

At well sites, gas driven pumps are commonly relied upon to inject chemicals such as methanol into process streams or circulate heat trace mediums to prevent processes from freezing in colder months. These pumps are a significant source of methane emissions in upstream oil and gas operations. They have been the technology of choice, despite the waste of gas on the exhaust stroke, because of low capital costs, the availability of pressurized natural gas and their simple design. At many remote northern sites, electricity is not available and the capital cost to retrofit existing pneumatic pumps with solar powered pumps is usually too high to generate an adequate return.

ConocoPhillips developed a method of reducing emissions coming from the pneumatic pumps at a relatively low cost. CPC worked during this project to customize a simple vent gas capture system to capture the vent gas from existing pneumatic systems and feed it to existing Catadyne™ heaters. A relatively simple solution that was proposed and implemented on chemical injection pumps was to use the fuel gas vented by the pump as fuel for on-site Catadyne™ building envelope heaters, which are usually in proximity to these venting pumps. Significant reductions in GHG emissions are possible because of the conversion of methane with an emission factor of 25 x the global warming potential of CO_2.

As shown in the figure below, the exhaust gas from the pneumatic pump is fed through a filter to remove any impurities. If the Catadyne™ heater requires fuel gas, the fuel gas is metered. If the Catadyne heater does not require fuel, the exhaust from the pump is sent to atmosphere. If insufficient fuel is provided by the pump, supplemental fuel is pulled from the fuel gas system.



Vent Gas Capture System Flow Chart and Installation

Project Details

- Five installations occurred on Bruin 5100 chemical injection pumps.
- Fuel flow from the pumps to the Catadyne™ heaters was metered so the vent gas capture efficiency and amount of abated methane to atmosphere could be proved.
- Make-up fuel for the Catadyne™ heater was un-metered.
- Final installation costs of $5,500 were much lower than the initial installation costs of $9,622, which was a cost reduction of over 40%.
- Installation cost reductions were related to the design costs as well as significantly lower on-site installation costs.


Flow Meter

Results

Results from the installations completed in this project are shown below:

Table 17. Overall results from Vent Gas Capture projects

	SAID	DID
Projects Completed	100	15
Cumulative and Verified GHG Reductions up to Dec. 2015	n/a	122 tCO_2e
Expected Yearly GHG Reductions	4,416 tCO_2e/yr.	159 tCO_2e/yr.
Cost Abatement	$1.70/$tCO_2e$	$21.40 /$tCO_2e$

Despite the limited sample size, some conclusions can be drawn about the cost-effectiveness of the CPC VGC system. The five installations that were capturing vent gas from chemical injection pumps were used to develop an average economic cost. Because the VGC system relies on the Catadyne™ heater, it is assumed in a given calendar year that the heater is operational 50% of the time when cold weather is prevalent.

Currently there is no approved carbon offset quantification protocol to cover the quantification of carbon reduction from the CPC vent gas capture system. Cap-Op Energy has put forth a proposal to the Government of Alberta to modify the Instrument Gas to Instrument Air Conversion in Process Control Systems (Instrument Air Protocol) to include the quantification of emissions reductions from gas driven pumps and controllers from high emission to low emission technologies.

"Golden Nuggets"/Project Takeaways

- The vent gas capture system undertaken by CPC in relation to gas driven pumps appears to be a broad based solution for methane vented from gas driven pumps.

- Measurement is required to match Catadyne™ heater fuel requirements and pump vented emissions.

- Back pressure on existing chemical injection pumps caused by the VGC system can result in the pumps stalling and failing to inject chemicals.

- There were higher than expected internal engineering and project management costs incurred by CPC in developing its own vent gas capture solution.

Knowledge Sharing Component

As part of its commitment to the Climate Change and Emissions Management Corporation, ConocoPhillips included in its proposal submission a knowledge sharing component with industry peers and the government. On December 4th, 2015 a Workshop was hosted at the ConocoPhillips Auditorium where over 200 people representing industry, technology/service providers and regulators attended.

Some of the overall learnings from the Workshop were:

- The project that achieved very good results (in terms of $/tonne GHG reduced) was the High to Low Bleed Instrument Conversions. The most effective implementation approach was to first get field level buy-in to ensure seamless on site activities and to use and train the same team of contractors to do the installs. This resulted in a significant reduction in operations time, project management time and in expense savings for the retrofits. Attendees also confirmed that there are a very large number of high bleed pneumatic devices around the province but in many cases their locations are not accurately known. Once the field trials of the first few installations were proven successful for ConocoPhillips, more resources were allocated to these projects and to developing a platform to maintain an inventory of these devices.

- Technologies to reduce GHG's do not have to be complex. For example, it is estimated that dehydration facilities (that are a significant source of GHG's in the upstream) are circulating twice the required amount of glycol. Field installations clearly showed that pump rate reductions could be effectively employed at facilities that were over circulating glycol. The glycol pump rate reductions demonstrated significant economic benefits and GHG reductions and were seen as having major potential for wider application in the industry.

- Two practical challenges that were common to the implementation of new technologies were found to be that of gaining acceptance at all levels of the company and the critical importance of the required skill sets for technologies that were not familiar. First, gaining acceptance of new technologies from upper management to the field level can take considerable time and education and this time should not be underestimated, particularly since the field personnel would be working with the technology on a daily basis.

- The second practical challenge, for the higher-risk projects that had not been trialled previously, was not only to have the people with the right expertise on the implementation team but to ensure that good relationships and communications were developed between industry, technology providers and regulators, in order to increase the chances of effectively deploying the technologies. Again this took considerable time and should be accounted for in the project management.

- There was general agreement that a funding mechanism, like CCEMC, was pivotal as a catalyst for supporting new technologies where, without such a mechanism, the return on investment would be marginal at best.

- A practical consideration that was raised about GHG reduction technologies with long payback periods in the current business environment was that although the GHG generating asset (e.g. gas plants) might be now owned by the company, it might be sold in the near future, making it difficult to obtain the budget for such an energy efficiency project.

- There was agreement that industry faced common challenges, namely to find ways to produce oil and gas with fewer emissions and a lower environmental footprint, while remaining competitive. It was also highlighted that an appropriate regulatory framework would be one that should enable industry to be energy efficient in what is now a different business environment.

Overall the workshop was considered to be a success. A Tabloid that highlights the results of the technology field implementations and of the Workshop can be obtained from the CETAC-WEST website (www.cetacwest.com) or by contacting CETAC-WEST at cetac@cetacwest.com.

Lessons Learned from Field Testing GHG Reduction Technologies

Consistency

When installing the same technology in multiple locations, it was found beneficial to find similar sites or conditions, in order to carry over the learnings from one project to the next. For example, during the REMVue AFR installations, ConocoPhillips focused on a standard engine that is used throughout most of their fleet, used panels that were customized to fit their needs and, for the most part, used the same installation crews.

Training

Providing specific training (e.g. lunch & learns) and other educational opportunities to field staff was vital in helping them understand and accept new technologies being installed on their sites. The training also promoted the relationships between operators and vendors, which assured the operators of support in the field.

For example, ConocoPhillips trained their contractors to start and stop wells. When doing the "High to Low Bleed Controller Technology Conversions", this eliminated the need for an operator to be on-site while the contractors were working, allowing the operators to do their every-day tasks.

Data Collection

Collecting pre and post installation data was critical for the company to validate results and be eligible for GHG credits. This might require additional expenses such as adding a meter for credit verification under the "Revised Quantification Protocol for Methane Venting Reductions".

In the case of vent gas, an additional advantage of having vent data metered and checked was to monitor the health of the equipment since increase in vent rates without changes in production might require maintenance of the seals.

Fit for Purpose

An economic necessity was that all equipment installed had to be fit for purpose. This meant that any new technology installed had to be designed to integrate with the rest of the equipment on site and with the characteristics of the location. It was found on several occasions that the site layout and vintage of current technology were not compatible with the proposed designs and technologies.

Creativity

There might be opportunities to combine technologies to create an optimal outcome. As an example, the implementation of a SlipStream System with a dehydration unit reduced a significant amount of GHG emissions. Other creative options might be available assuming a compatible location and site layout.

Ability to Change

It was found important to be flexible in planning, build on the momentum of early successes and to shift focus if needed. Putting an emphasis on certain successful projects has allowed ConocoPhillips to double the GHG reduction expectations of the project.

Complying with Regulations

When installing new technology, whether domestic or imported, it was critical to fully understand the technology and to meet the relevant regulatory requirements (such as those of the CSA and ABSA). These challenges were clearly evident in the attempt to implement the heat pipe technology during the “Waste Heat Recovery” project.

Database Development

In several of the energy efficiency projects, a common challenge was knowing where and what equipment was in the field, since there was no database with this information. ConocoPhillips, in partnership with Cap-Op Energy, has created an App in order to start documenting some of the equipment that currently exists in the field. This problem of identifying existing equipment has been confirmed by other companies.

Stock-up

When installing the same technology in different field locations, there were significant benefits to having an inventory on hand of the technology and installation equipment needed. This not only provided a discount on the purchase of the technology/equipment but also prevented delivery delays. In addition, even though certain installs can only be done during plant turnaround or routine scheduled maintenance, when there are unplanned outages in the field and if the technology/equipment is on hand, the installs can be done during these times.

There are benefits from sourcing materials from the same vendor that does the installation in terms of price discounts and assurance that everything is done right during installations. It was also found useful to have a back-up contractor that could continue the work in the event of the non-availability of the current contractor.

Internal Energy Efficiency Focus

Sustained management and field support for the energy efficiency projects were crucial to the success of the program. Prior to the start of this project, ConocoPhillips had an energy efficiency department dedicated to reducing GHG emissions and with a committed operations staff and a dedicated budget. This department served as a critical focal point for the implementation of the GHG reduction technologies.

Conclusions

The two main goals of this project were to:

1. Execute projects to reduce greenhouse gas (GHG) emissions at Upstream Oil and Gas facilities in ConocoPhillips Western Canada Gas Operations, and

2. Encourage widespread industry adoption of GHG reduction projects by sharing the results and learnings with a wide industry and government audience.

The initial target for the program was to reduce GHG emissions by 50,000 tCO_2e/yr. Due to a shift in focus towards the projects that were showing early success, the program resulted in reductions of over 90,000 tCO_2e/yr. Results from the project are shown in Figure 6 below. For a more accurate representation of the final project results, please refer to Table 2 on page 5.

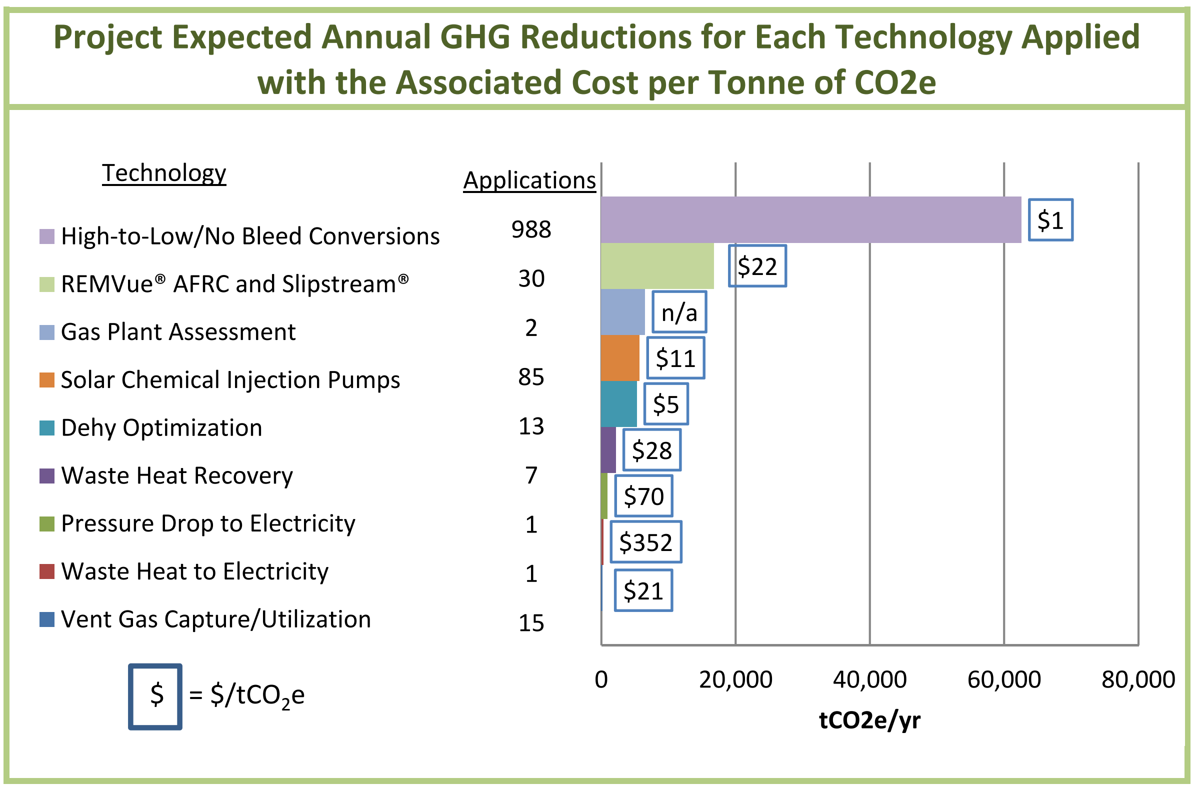


Figure 6 Summary of Technology Results

The learnings from the project were shared with industry through a Workshop held at the ConocoPhillips auditorium on December 4th, 2015. This Workshop presented the results achieved and learnings from the projects together with discussions in a panel format with other industry players. With oil and gas producers, technology developers, and regulators in the audience and on the panels, the Workshop resulted in an industry wide sharing of learnings from a wide variety of companies.

The Workshop also highlighted some of the energy efficiency initiatives ConocoPhillips has been pursuing for the past few years as well as how CCEMC has been a catalyst in helping industry reduce GHG emissions. From a broader perspective, this Workshop presented for the first time the results of extensive field tests with a variety of GHG reduction technologies and highlighted some of the steps that Alberta has been taking to reduce emissions.

This CCEMC project has been a major catalyst for innovation and technology adoption within the ConocoPhillips fleet. Since 2011, this project has resulted in:

- The development of new technologies.
- The importation of technologies from other countries that have never had an installation in North America.
- New technologies being trialed and accepted company-wide across ConocoPhillips operation.