Final Outcomes Report

Lashburn CO_2 Capture Demonstration Project

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Executive Summary

In November 2012, a project agreement for the "Lashburn CO2 Capture Demonstration Project" was signed between the Climate Change and Emissions Management (CCEMC) Corporation (now Emissions Reduction Alberta, ERA) and Husky Oil Operations Ltd. This is the final outcomes report for the project.

Initial start-up of the capture plant was in Q3 2015. Overall, the plant has run for 143 days of non-continuous operation due to a number of operational issues since startup. This equates to an overall runtime of 17% to the end of June 2017.

During operation, the plant has captured a total of 1,933 tonnes of CO2 which has been used for enhanced oil recovery (EOR) operations in the area.

The plant has experienced many operational issues since startup. The issues are varied, however, the majority can be classified as either mechanical issues or process issues.

In order to rectify many of these issues, many repairs, improvements and changes have been made to the plant. The major changes are as follows:

- Multiple amine solution replacements
- Reclaimer waste system upgrades
- Piping replacements and upgrades
- Amine reboiler replacement (steam reboiler vs. direct-fired reboiler)
- Amine system cleaning

Due to the limited runtime of the plant, Husky has not provided any final conclusions regarding the project. Husky continues to work with HTC to further understand the potential cost and energy impacts of this technology. Husky and HTC will continue working together to optimize plant efficiency, operability and CO2 capture.

Husky is committed to the operation of this plant to fulfill the intent of the project agreement. This includes implementation of a technology verification plan and testing of MEA and HTC proprietary solvents. Technical data showing results of the test will be provided as part of the follow-up evaluation in 2019.

1. Project Description

1.1 Introduction and Background

This project has been undertaken to evaluate a proprietary solvent-based CO2 capture technology with a goal to reduce CO2 emissions and to capture CO2 for enhanced heavy oil recovery opportunities in Alberta and Saskatchewan.

The novel aspect of this CO2 capture trial is the use of proprietary (amine-based) solvents. These solvents have been developed by HTC CO2 Systems. HTC has also incorporated several novel design elements (ex. use of their Delta Reclaimer, use of a simplified internal wash system to reduce amine losses and use of high-efficiency packing) in an attempt to lower overall costs and increase efficiency of the post-combustion CO2 capture process.

HTC's solvents have been developed and tested in the International Test Centre at the University of Regina and the 5 tonne per day (tpd) Boundary Dam Demonstration Plant. Husky executed this project in order to evaluate the technology in a larger demonstration test facility near Lashburn, Saskatchewan by capturing CO2 from a Once-Through Steam Generator (OTSG) prior to considering large scale commercial plants.

1.2 Technology description

The application of solvent-based systems for post-combustion CO2 capture is well known. The use of solvent or amine to capture CO2 from a post-combustion flue gas stream is proven technology. The main differentiator for this project is the type of solvent used for CO2 capture. If successful, the use of HTC's proprietary solvents have the potential to reduce capital and operating costs for the post-combustion CO2 capture process at a commercial scale. Four solvents will be tested at the plant: Two MEA solvents will be tested to provide baseline data for the plant followed by two proprietary solvents (designed by HTC).

In addition to the use of proprietary solvents, HTC has incorporated several new technologies into the CO2 capture plant which may improve the post-combustion CO2 capture process in the future. Examples of these technologies include:

- Direct-fired amine reboiler
- Vacuum amine reclaimer (Delta Reclaimer)
- Internal wash section on amine absorber (simplified system)
- Direct contact cooler (DCC)
- High efficiency stainless steel packing

The plant installed at Lashburn is designed to capture 30 +/- 5 tonnes/day of CO2 from the flue gas of a once through steam generator (OTSG) at the Lashburn site with HTC formulated solvents. The plant is designed to capture 20 +/- tonnes/day of CO2 with standard MEA. .

Below is a block flow diagram and brief description of the process at the Lashburn capture site:

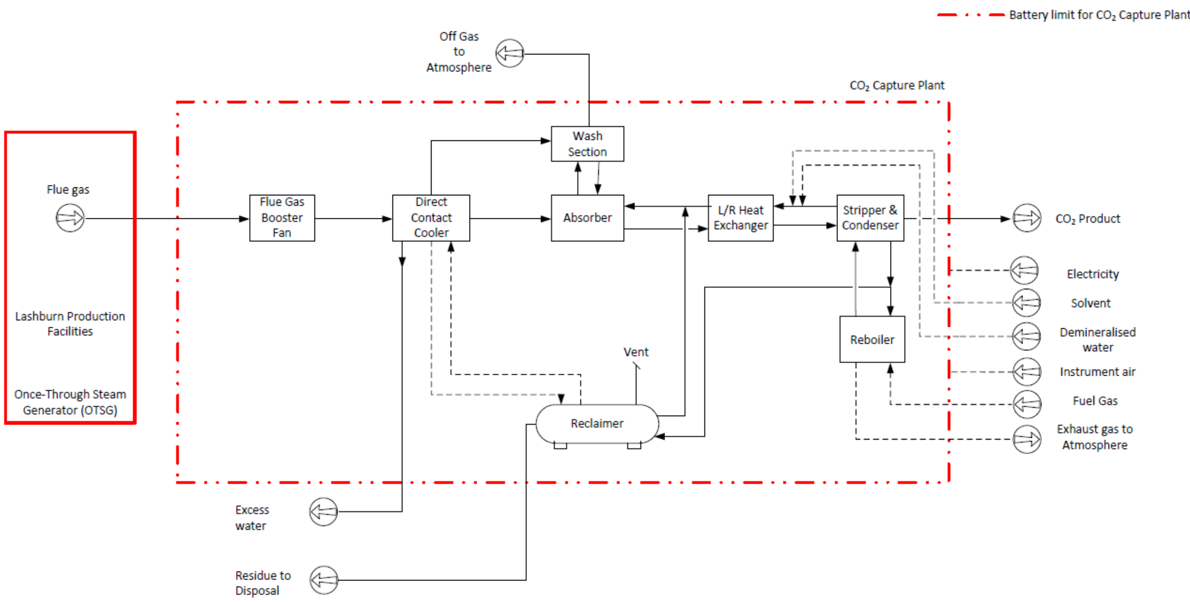

Figure 1: CO2 Capture Plant Block Flow Diagram

Flue gas from a Once-Through Steam Generator (OTSG) is directed to the capture plant unit via a flue gas booster fan (or blower).

The flue gas then enters the bottom of the Direct Contact Cooler (DCC) tower where it flows upwards and is cooled by a cooling water stream flowing downwards through the tower. The direct contact cooling of the flue gas with water is more efficient than a heat exchanger or other method of cooling methods. Furthermore, the DCC makes the plant self-sufficient for water make-up supply.

After exiting the DCC, the flue gas enters the absorber at the bottom of the tower and flows upwards through a packing material. As the exhaust flows upwards through the absorber, lean amine is injected near the top of the tower and flows downward over the packing material to allow it to intimately contact the exhaust stream in counter-current flow. The DCC and absorber were equipped with a newly developed high efficiency stainless steel packing material. FLEXIPAC® 350X Structured packing was used in the absorber in an attempt to lower pressure drop and enhance the mass and heat transfer efficiency within the tower. Rich amine (amine loaded with CO2) flows to the bottom of the absorber.

As the off-gas stream (i.e. flue gas stream with CO2 removed) exits the top of the vessel, there is a wash water section which sprays the exhaust before it exits out the top of the vessel to atmosphere. The washing section was designed to operate in one of two separate modes: external washing and internal washing. Both modes of operation should allow the plant to operate with minimal amine losses in the off-gas stream. The advantage of the internal wash system is that it simplifies the overall process with less overall equipment necessary for operation. It is anticipated that this would lower the capital cost of a commercial scale CO2 capture plant.

After leaving the absorber, rich amine flows through the lean/rich amine heat exchanger where the temperature of the lean and rich amine streams are moderated to improve overall energy efficiency of the process. Rich amine flows to the inlet of the regenerator tower. Rich amine is injected into the top of the regenerator and flows downwards through a series of trays. Stripping steam flows upwards through the tower trays to regenerate the solvent and release the CO_2 from solution. Lean amine collects at the bottom of the vessel and flows to a surge tank. A slipstream of lean amine is pumped to the amine reboiler. The reboiler generates the stripping steam for the tower. The original design (and during initial operation) involved the use of a direct-fired amine reboiler. The reason for choosing to use this type of reboiler was to increase the overall energy efficiency of the process. The equipment supplier quoted a heater efficiency of 80% (compared to some traditional heaters whose efficiency can be in the 75% range).The direct fired reboiler also requires a smaller inventory of solvent to operate. The remainder of the lean amine is pumped back to the top of the absorber where it begins the absorption/regeneration cycle once more.

CO_2 flows out the top of the amine regeneration tower and through an amine reflux condenser and reflux accumulator (to condense and recover any amine remaining in the gas stream). Condensed liquids are pumped back into the top of the regenerator tower. CO_2 gas flows from the reflux accumulator to the outlet of the plant and on to the enhanced oil recovery (EOR) injection site.

The plant does not include dehydration, compression or liquefaction of the CO_2 product stream. The CO_2 is pipelined to a nearby EOR site for injection.

A picture of the plant (as installed) is shown below:

Figure 2: CO_2 Capture Plant at Lashburn

A small slipstream of lean amine is taken (as required) from the discharge of the reboiler pump and sent to the Delta Reclaimer™, which is a designed by HTC. The Reclaimer is operated when solvent sample testing indicates that heat stable salts (HSS) and other degradation products have reached a concentration that will impact the performance of the CO_2 capture plant. The feed solvent is boiled up in the Reclaimer under a vacuum and condensed in the overhead condenser to form the reclaimed solvent that is returned to the lean amine solution.

HSS and degradation products that do not vaporize are removed from the Reclaimer to drums for waste disposal. The Delta Reclaimer has several unique features compared to other commercial solvent reclaimer as follows;

- Simple process with few unit operations
- High solvent purity (restore the quality almost as the fresh solvent),
- Lower energy consumption
- Reduced waste for disposal by concentrating the impurities and recovering as much as possible useful amine.

1.3 Project Goals

As per the original application, there are two main goals for this project:

1) Cost and technology validation:
   This project seeks to help define the costs associated with a specific application of HTC's existing technology on an OTSG similar to those employed in SAGD (Steam Assisted Gravity Drainage) or CSS (Cyclic Steam Stimulation) thermal processes. Validation of these technologies creates potential to further reduce these costs significantly over time, and thereby substantially increase the performance of solvent based CO_2 capture technologies.

2) Develop and demonstrate the ability to integrate the operations of an OTSG and flue gas CO_2 capture process:
   This is an essential step that must be taken before utilization of CO_2 capture at larger commercial sized projects where reliable and continuous OTSG operation is critical for thermal oil production

The goals of this project have not changed since the outset of the project.

Due to ongoing operational issues (discussed further in section 2.3), work on the above goals is ongoing. Husky and HTC are committed to continue to move forward with this project and fulfill the intent of the project proposal. As a result, the goals listed above are still valid and work is actively taking place to achieve them. A further follow-up report will be provided in 2019.

1.4 Work Scope overview

The scope of this project involves the design, construction and operation of a solvent-based CO_2 capture plant near Lashburn, SK. The plant is designed to capture upwards of 30 +/- 5 tonnes/day of CO_2 from a flue gas stream containing ~ 8% CO_2 at near atmospheric pressure with HTC formulated solvents. The plant is designed to capture 20 +/-5 tonnes/day of CO_2 using standard MEA solvent.

The scope also includes a technology verification program to evaluate and validate all necessary operational criteria for the plant. The technology verification program is further discussed in section 2.

2. Outcomes and Learnings

Final outcomes in terms of technology verification are not available at this time. Work on this project is continuing and final outcomes and learnings will be provided as part of a follow-up report in 2019. The following section illustrates the outcomes and learnings of the project to date.

Initial start-up of the capture plant was in August 2015 with first production from the plant on September 15th, 2015. Overall, the plant has run for 143 days of non-continuous operation since startup. Overall runtime for the plant was 17% from September 2015 to the end of June 2017. During operation, the plant has captured a total of 1,933 tonnes of CO2 which has been used for EOR operations in the area.

There have been a number of issues which have led to low plant reliability. Issues can be defined as mechanical issues or process issues. These issues are discussed in more detail throughout this section. It should be noted that in the majority of instances (both mechanical and process-related), the root cause has not been inherently linked to the mechanical or process design of the plant.

2.1 Technology Verification Program

In order to fulfill the first goal of the project (cost and technology verification), a technology verification program was developed for the project. The following is a summary of the results obtained to date for each aspect of the test plan:

2.1.1 CO2 capture rate

To date, a total of 1,933 tonnes of CO2 have been captured at the plant. For MEA, a peak rate of 20 tonnes/day has been reached (in February 2016). It is anticipated that once the plant is back to operational status, the target will remain 30 +/- 5 tonnes/day of CO2 captured for HTC's proprietary solvents. .

2.1.2 CO2 product purity

CO2 purity was not continuously monitored throughout the test period and there is no in-line CO2 analysis installed at the plant. Point samples were taken using a hand pump and gas detection tube and showed high purity. Results were used to ensure that the amine was capturing CO2 but results were not recorded. Once the plant comes back online and is operating in steady state, CO2 purity will be routinely monitored. HTC anticipates that CO2 purity will be in the range of 97%.

2.1.3 Solvent loss

Solvent losses have not been calculated for this trial to date. To date, several full-scale amine batches have been removed and added to the system due to contamination of the solvent. The source of contamination will be further investigated during continued operation of the plant.

2.1.4 Utility consumption

Utility consumption data has not been reviewed at this time as the plant has not been operated in a continuous, steady state manner. During the longest uninterrupted operation period, average fuel gas usage was measured as 2.2 Se^3m^3/d (77.7 mcf/d) however actual steady operation consumption can be different.

2.1.5 Emissions to atmosphere

When the plant is operational, vent volumes of the remaining flue gases are monitored. At this time, detailed analysis of the emissions to atmosphere have not been provided.

2.1.6 Liquid effluent rate and composition

Liquid effluent rate was not measured for the test period due to unsteady operations. Once the plant is operating in a continuous, steady state manner, liquid effluent rate will be measured and composition will be analyzed.

2.1.7 Waste generation

Regenerator waste was not measured for the test period due to unsteady operations. Once the plant is operating in a continuous, steady state manner, products from the reclaimer will be measured and composition will be analyzed.

As per the technology verification program document, the goal is to collect performance data collected from a minimum of 3,000 hours of continuous (uninterrupted) operation and shall include at least one reclaimer operation cycle. To the end of August 2017, the longest continuous runtime for the plant was just over 700 hours.

2.2 Field Test Results

Field test results are very limited at this time. The data below show the amount of CO2 captured by the plant to date, along with plant runtime information.

Table 1: Capture Plant Production and Runtime

Month:	Solvent	Production (tonnes)	Days Online	Runtime (Hours)	Average Daily Production
August 2015	DeltaSolv-2	0	6	0	0
September 2015		186	20	240	6.2
October 2015		251	15	237	8.1
November 2015		0	0	0	0
December 2015		0	0	0	0
January 2016	MEA (20 wt%)	0	0	0	0
February 2016		345	21	440	11.9
March 2016		0	0	0	0
April 2016		286	20	433	9.5
May 2016		221	18	362	7.1
June 2016		0	0	0	0
July 2016		0	0	0	0
August 2016		63	5	88	2.0
September 2016		288	20	444	9.6
October 2016		0	0	0	0
November 2016		198	15	349	6.6
December 2016		95	9	214	3.1
January 2017		0	0	0	0
February 2017		0	0	0	0
March 2017		0	0	0	0
April 2017		0	0	0	0
May 2017		0	0	0	0
June 2017		0	0	0	0
Total:		**1,933**	**143**	**2,807**	**3.0**

2.3 Operational Issues

There have been many operational issues with the capture plant since start-up. These issues can be categorized as either mechanical issues or process issues. Below is a summary of the issues experienced to date.

It should again be noted that in the majority of instances (both mechanical and process-related), the root cause has not been inherently linked to the mechanical or process design of the plant. One hypothesis it is that contamination of the system prior to initial start-up has led to many of the issues listed below.

2.3.1 Mechanical Issues

The majority of downtime at the plant has been caused by mechanical-related issues. These issues are classified in three areas:

1) <u>Amine Reboiler Design and Operation:</u>

During operation of the capture plant there were three separate plant shutdowns due to the amine reboiler.

As a result of the outages associated with the reboiler package, a decision was made in December 2016 to replace the direct-fired reboiler with a conventional steam-type reboiler. Use of a conventional design should increase plant reliability.

There may be further opportunity for study of the direct-fired reboiler concept in order to increase overall plant efficiency while maintaining high plant reliability. There is no intent at the current time to further study this design.

2) Plant Piping Integrity:

During one of the plant startups (September/October 2015), the plant piping was flushed with an improper cleaning agent. After this occurred a full review of plant integrity was undertaken and piping was replaced as necessary. This resulted in the plant being offline from October 2015 through to February 2016. This likely also contributed to downtime in March and April 2016.

Husky has also replaced many threaded (union-type) connections with welded or flanged connections throughout the plant in order to reduce the number of potential leak points in the system. This set of piping replacements took place in late August/early September 2016.

3) Use of Legacy Equipment:

The majority of piping and equipment that make up the plant were in “used” condition. While there were inspections conducted for all major equipment and piping for the plant, there were a number of issues found with the use of legacy equipment. From a mechanical point of view, several pieces of equipment and piping have been proactively replaced due to integrity concerns.

2.3.2 Process Issues

There have been several plant outages and significant downtime associated with process-related issues.

The root cause of these process issues has not yet been determined. Due to low plant reliability, it has not been possible to establish steady-state operating conditions for any significant length of time. As such, troubleshooting and root cause investigation have been challenging. One hypothesis is that contaminants contained in the system prior to initial plant start-up have caused many of the issues listed below. Contaminants found in the system prior to initial operation may have led to the solvent being adversely affected. While there were several attempts made to clean out the system prior to initial start-up, those efforts may not have been successful in removing 100% of contaminants.

As of the time of writing, most of the process issues have been caused by apparent foaming of the amine solution. Investigation is ongoing and will continue as the plant returns to operation. Experts from HTC will continue to work with Husky to identify root causes of the apparent foaming and try to eliminate this issue.

Apparent foaming has resulted in the plant outages in February, April and November in 2016.
During the plant outage from December 2016 – July 2017, many other small projects and inspections have been completed at the plant. The plant has been inspected for signs of fouling and corrosion which have the potential to impact the plant upon re-starting. Where any issues have been found they have been rectified.

2.4 Lessons Learned

There have been many lessons learned to date. The most impactful are:

1) Ensure subject matter experts are available for detailed solvent (and degradation product) analysis. Proper understanding of solvent chemistry and degradation products are key in identifying root causes of operational process issues
2) Where available, use conventional gas-plant type design for post-combustion capture applications. Use of a conventional amine reboiler vs. a direct-fired reboiler may have improved plant operability and increased run-time.
3) When possible, use new equipment to minimize risk of previous damage (or contamination). Used equipment may come with lower up-front cost, but significantly increases risk of poor plant reliability.

3. Greenhouse Gas and Non-GHG Impacts

3.1 Greenhouse Gas Benefits

During operation thus far, approximately 1,933 tonnes of CO_2 have been captured by this project. CO_2 has been pipelined to the nearby Lashburn EOR injection site for use in heavy oil EOR. CO_2 is used in the EOR process and is conserved by the cyclic process. Incidental storage of the CO_2 occurs at the end of each production cycle. While using the direct-fired reboiler, an incremental 4 – 6 tonnes/day of CO_2 was generated by running the unit. When the conventional steam reboiler was installed, the direct emission from the reboiler was eliminated. Steam to the reboiler is now being provided by the OTSG from which flue gas is being captured, so incremental CO_2 is not being generated.

At this time, cost per tonne of CO_2 cannot be calculated due to operational issues. Once steady-state operation is achieved, a detailed analysis on the overall capture cost per tonne will be performed.

Under steady state operation, the plant is designed to capture 30 +/- 5 tonnes/day of CO_2 with HTC's formulated solvents (9,300 tonnes/year at 85% plant reliability).

If proven commercially and technically viable, this technology has the potential to capture significantly more CO_2 from Husky's thermal operations for EOR application. If adopted by industry, the capture potential is much higher still (>1MT/year).

3.2 Immediate and Future Non-GHG Benefits

The project, once operational, will provide an input CO_2 stream for the use in EOR applications.

Formulated solvents from HTC are anticipated to have lower levels of volatility leading to lower amine losses. This will minimize amine consumption rates and minimize loss of amine to the process.

4. Overall Conclusions

This project requires additional operational data in order to provide any conclusions. Husky is committed to the operation of this plant to fulfill the intent of the technology verification plan, including testing of MEA and HTC proprietary solvents. Technical data showing results of the test will be provided as part of the follow-up evaluation in 2019.

Based on some operational data, it does appear as thought the plant will be capable of producing upwards of 22 tonnes/day of CO_2 with 20% MEA. Plant performance using formulated solvents should allow for additional CO_2 capture with lower energy intensity for regeneration of the solvent.

5. Scientific Achievements

As of the time of writing, no patents, books, journal articles, conference presentations, student theses or other publications have been written regarding this project.

After conclusion of the technology verification plan, there may be the potential for data from the project to be used for publication within the scientific community.

6. Next Steps

Husky is committed to the operation of this project and fulfilling the intent of the technology verification plan. As of the time of writing, a new steam reboiler is being installed and commissioned at the plant. The purpose of installing the new reboiler is to increase plant reliability and decrease the likelihood of amine degradation as the operation of the plant continues. Finally, upgrades to the reclaimer unit have been made (to the waste handling system, control system programming and cooling water utility) in an attempt to increase plant reliability

The technology verification plan, including testing of MEA and HTC proprietary solvents is scheduled to resume in August of 2017. Data will be collected going-forward in an effort to complete all aspects of the technology verification plan by 2019.

7. Communication Plan

After completing the technology verification plan, a follow-up report will be issued to ERA.