OFFSET PROJECT REPORT:

TAYLOR TURIN
ACID GAS INJECTION PROJECT

FINAL

FEBRUARY, 2011

Prepared by: Blue Source Canada ULC
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1. PROJECT INFORMATION

The Taylor Acid Gas Injection Project (the Project) is an acid gas injection (AGI) project located at the Taylor Gas Processing Limited Partnership Turin Sour Gas Processing Plant located near Turin, Alberta. The Project is owned and operated by Taylor Gas Processing Limited Partnership (Taylor).

The Taylor Turin Sour Gas Processing Plant began operations in 1974, was purchased by Taylor in 2003, and has a total licensed capacity of 44 million standard cubic feet per day (mmscf/d). Before the implementation of the acid gas injection system, Taylor was mandated to implement a sulphur control system at its Turin facility due to de-grandfathering (termination of regulated pre-existing sulphur emissions levels) at the Turin sour gas processing facility. The requirement to de-grandfather these facilities resulted from an application to expand capacity at the plant made by the previous owners of the facility, Vista Energy Resources Ltd. (Vista). As a result of this de-grandfathering, Alberta Environment imposed a requirement on Taylor equivalent to reduce sulphur emissions by seventy percent of the amount approved under the previous permit. This revision to the operating permit did not address the carbon dioxide emissions from the facility. A three bed (three stage) Claus process unit was the preferred sulphur treatment option to implement at the facility to convert gaseous H_2S to elemental sulphur.

To meet the requirement to reduce sulphur emissions, Taylor reviewed available technology alternatives and despite the similar cost and lower technical risk of other alternatives, chose to implement an acid gas injection program. There were no regulatory barriers to prevent the acid gas injection project from proceeding and the Alberta Energy Utilities Board and Alberta Environment granted permits for the project.

In 2004, construction of the acid gas injection system was completed instead of the installation of a Claus process unit. The operation of the acid gas injection facility will result in a net reduction in direct greenhouse gas emissions from the geological sequestration of carbon dioxide contained in the acid gas stream and indirect emissions from the reduction of fossil fuel usage to treat sulphur emissions. The acid gas, containing primarily carbon dioxide, is compressed and transported approximately 1.5 kilometers and injected into a well-characterized depleted natural gas reservoir which results in essentially permanent geological sequestration (>1000 years).

Beginning in 2007, acid gas from the Retlaw facility was diverted to Turin and commingled with the rest of the acid gas stream. The diversion of the gas to Retlaw was based on process economics of scale and as such the baseline for Turin remains in effect for the gas diverted from Retlaw. Retlaw volumes are therefore included in the quantification of emission reductions for 2007.

The attached Offset Project Plan (Appendix A) has been completed in accordance with the Alberta Offset System Project Guidance Document (AENV, 2007). The Project complies with the Alberta Offset System Quantification Protocol for Acid Gas Injection: Version 1 (May 2008).

The opportunity for generating carbon offsets with this protocol arises from the direct greenhouse gas emission reductions resulting from the geological sequestration of acid gas streams originating from raw natural gas processing operations that contain carbon dioxide due to the avoided use of fossil fuels that would have been required to operate the alternative Claus process unit.

2. REPORTING PERIOD

For this project, the carbon dioxide equivalent emission reduction credits are claimed for activities from January 1st, 2010 to December 31st, 2010. No changes to the project operation occurred during this time.

3. GHG CALCULATION

GHG emission reductions were calculated following the Alberta Offset System Quantification Protocol for Acid Gas Injection: Version 1 (May 2008). The activities and procedures outlined in the Offset Project Plan provide a detailed description of the project's adherence to the requirements of the quantification protocol.

Based on the methodology outlined in the Protocol and as stated in the Notice of Creation of Emission Reduction Credits, the following is a summary of emission reductions for this project as calculated for the current reporting period of the project:

2010: January 1st to December 31st					
	CO_2 (t CO_2)	**CH_4 (t CH_4)**	**N_2O (t N_2O)**	**CO_{2E} (t CO_{2E})**	**Total* (t CO_{2E})**
Baseline	68,883	160	1	-	72,628
Project	928	1	-	-	954
Net Emission Reductions	67,954	159	1	-	**71,674**

*Totals may not add exactly up due to rounding.

4. PROJECT AND PROPONENT IDENTIFICATION

The project proponent is Taylor Gas Processing Ltd. Partnership. Contact information is provided below.

Taylor Gas Processing Ltd. Partnership
c/o AltaGas Ltd.
1700, 355 4th Avenue SW
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Attn: Jon Remmer

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Fax: (403) 691-7134
Email: jon.remmer@altagas.com

5. PROJECT DEVELOPER SIGNATURES

The project developer has executed this project report as of the 22 day of Feb, 2011.

Taylor Gas Processing Ltd. Partnership

Signature: ____________________

Name: Jon Remmer

Title: Operations Engineer

Appendix A

Offset Project Plan:
Taylor Turin Acid Gas Injection Project – Final (February, 2011)

Blue Source Canada

OFFSET PROJECT PLAN:

TAYLOR TURIN
ACID GAS INJECTION PROJECT

FINAL

FEBRUARY 2011

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1 Introduction

The Taylor Acid Gas Injection Project (the Project) is an acid gas injection (AGI) project located at the Taylor Gas Processing Limited Partnership Turin Sour Gas Processing Plant located near Turin, Alberta. The Project is owned and operated by Taylor Gas Processing Limited Partnership (Taylor).

The Taylor Turin Sour Gas Processing Plant began operations in 1974, was purchased by Taylor in 2003, and has a total licensed capacity of 44 million standard cubic feet per day (mmscf/d). Before the implementation of the acid gas injection system, Taylor was mandated to implement a sulphur control system at its Turin facility due to de-grandfathering (termination of regulated pre-existing sulphur emissions levels) at the Turin sour gas processing facility. The requirement to de-grandfather these facilities resulted from an application to expand capacity at the plant made by the previous owners of the facility, Vista Energy Resources Ltd. (Vista). As a result of this de-grandfathering, Alberta Environment imposed a requirement on Taylor equivalent to reduce sulphur emissions by seventy percent of the amount approved under the previous permit. This revision to the operating permit did not address the carbon dioxide emissions from the facility. A three bed (three stage) Claus process unit was the preferred sulphur treatment option to implement at the facility to convert gaseous H_2S to elemental sulphur.

To meet the requirement to reduce sulphur emissions, Taylor reviewed available technology alternatives and despite the similar cost and lower technical risk of other alternatives, chose to implement an acid gas injection program. There were no regulatory barriers to prevent the acid gas injection project from proceeding and the Alberta Energy Utilities Board and Alberta Environment granted permits for the project.

In 2004, construction of the acid gas injection system was completed instead of the installation of a Claus process unit. The operation of the acid gas injection facility will result in a net reduction in direct greenhouse gas emissions from the geological sequestration of carbon dioxide contained in the acid gas stream and indirect emissions from the reduction of fossil fuel usage to treat sulphur emissions. The acid gas, containing primarily carbon dioxide, is compressed and transported approximately 1.5 kilometers and injected into a well-characterized depleted natural gas reservoir which results in essentially permanent geological sequestration (>1000 years).

Beginning in 2007, acid gas from the Retlaw facility was diverted to Turin and commingled with the rest of the acid gas stream. The diversion of the gas to Retlaw was based on process economics of scale and as such the baseline for Turin remains in effect for the gas diverted from Retlaw. Retlaw volumes are therefore included in the quantification of emission reductions for 2007.

This Offset Project Plan has been completed in accordance with the Alberta Offset System Project Guidance Document (AENV, 2007). The Project complies with the Alberta Offset System Quantification Protocol for Acid Gas Injection (2008).

2 Project and Proponent Identification

The acid gas waste stream at the Turin Sour Gas Processing Plant that would have been processed through the current sulphur recovery process unit, resulting in the direct and indirect emissions of greenhouse gases, is instead diverted to an injection facility where it is geologically sequestered in a well characterized reservoir.

The project proponent is Taylor. Contact information is provided below.

Corporate Contact Information:

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Direct and indirect emission reductions generated by the Project are owned solely by Taylor. As a gas processing company with no ownership of oil or gas production assets, Taylor had to negotiate with area gas producers to secure the right to dispose of acid gas in one of their reservoirs. Taylor acquired ownership of the injection well from Provident and has Provident's consent to operate the injection program. This Offset Project Plan covers all direct and indirect emissions generated by the project.

3 Project Description

3.1 Project Scope

The opportunity for generating carbon offsets with this protocol arises from the direct greenhouse gas emission reductions resulting from the geological sequestration of acid gas streams originating from raw natural gas processing operations that contain carbon dioxide due to the avoided use of fossil fuels that would have been required to operate the alternative Claus process unit.

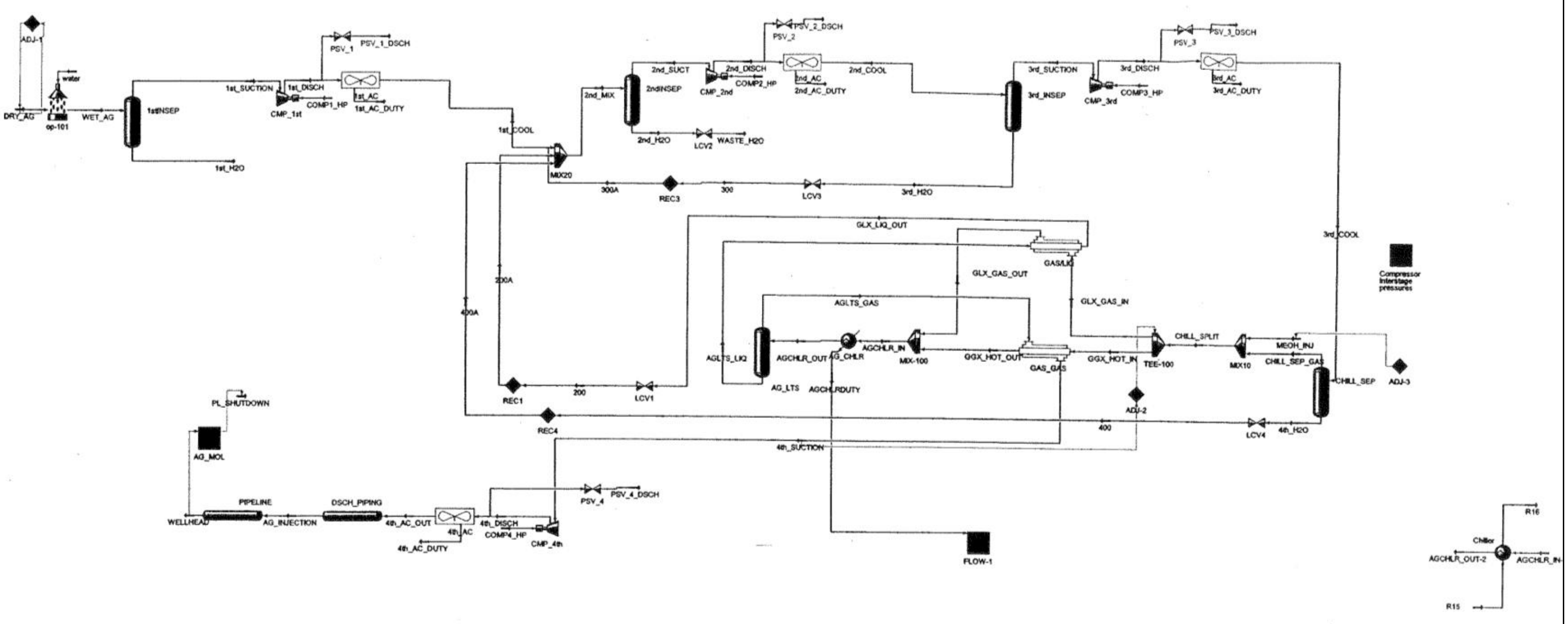
In the project condition capture and permanent sequestration of the entire acid gas stream directly reduces the quantity of CO_2 released to the atmosphere. Further, the process of compression, transportation, and sequestration of acid gas reduces the quantity of GHG released to the atmosphere as it is a less energy intensive process than the baseline processes (multi-stage Claus process) required for safe disposal of the sulphur contained within the acid gas stream.

The acid gas injection system includes infrastructure for gas compression, pipeline transportation, injection and process monitoring. The acid gas stream is diverted through a compressor to boost the pressure of this stream for transportation through the pipeline and into the injection well. There are various monitoring instruments along the way to measure system operating parameters as well as to ensure there is no leakage from the on-site infrastructure or from the reservoir. Due to the toxicity of the acid gas, leakage is prevented as per Alberta EUB Approval #10630.

The geological sequestration of the acid gas stream is also considered permanent based on the assessed integrity of the reservoir into which the acid gas is being disposed. The geological assessment was a requirement of the Alberta EUB Approval No. 9959 required for the implementation of the acid gas injection process. Regulations relative to the hydrogen sulphide content of the acid gas stream provides added assurance that the sequestration is permanent.

A process flow diagram illustrating the general components of the project is provided as Figure 3.1.

Figure 3.1: Turin Acid Gas Injection Process Flow Diagram



3.2 PROJECT SITE DEFINITION

The Turin sour gas processing plant, operated by Taylor, is a sour gas processing facility with a licensed capacity of 44 mmscf/d. A site plan for the Turin facility is provided in Figure 3.2.

The plant consists of inlet separation, approximately 3,200 horsepower of inlet compression, a sweetening train and a refrigeration system. The emission reductions contemplated under this report are relative to the back-end treatment and disposal of the acid gas stream generated as a result of the processing of the hydrocarbon feedstock at the facility.

The formation being injected into is called the Mannville Y Pool. This reservoir contains 5 completed wells. These wells include:

00/01-14-012-19W4/0 - non-producing

02/01-14-012-19W4/0 - non-producing

00/03-25-012-19W4/0 - injection well

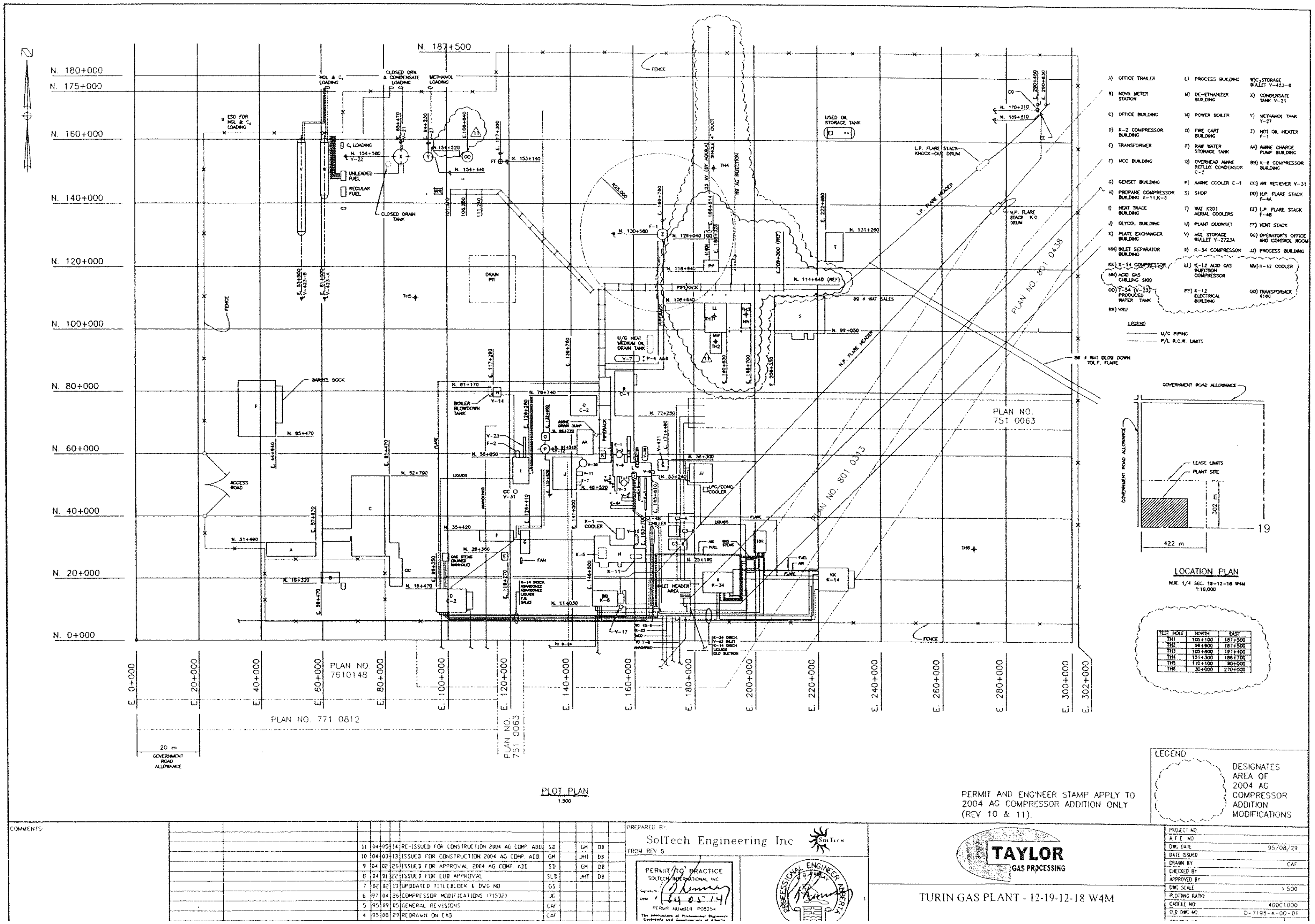
00/14-13-012-19W4/2 - producing gas well shut in March 2007

00/06-24-012-19W4/0 - producing gas well shut in March 2006

A set of maps of the project site and surrounding region, showing both the plant, gathering systems, the formation being injected into and the neighboring wells is available to verifiers upon request. Documentation on the history, status and ownership of the neighboring wells, as well as copies of the letters notifying the owners of these wells of the intended acid gas injection program, are similarly available to verifiers upon request.

Taylor’s compliance, as well as that of other stakeholders such as the land owners, with the injection program is evidenced by the approval from the Alberta EUB granting Taylor the rights to operate the injection program. Further, the approvals from the Alberta EUB and Alberta Environment provide evidence that the Government of Alberta approves of the injection program.

Figure 3.2: Turin Site Plan



3.3 PRE-PROJECT CONDITIONS

Given the requirement to reduce sulphur emissions, the baseline condition for the plant is the installation of a multi-bed Claus process facility at the plant, to convert hydrogen sulfide to elemental sulphur. The Claus process investigated by Taylor would have met the required standards for treatment of the acid gas stream and would have represented a lower cost option for addressing the requirements of the facility license subsequent to the de-grandfathering of the facility.

Acid gas with H_2S concentration less than 3% provides a challenge for sulphur recovery. A large number of processes were evaluated by Taylor as well as the previous owner of Turin, Vista Midstream. These included the New Paradigm Biological Process, Flex-Sorb Tail Gas Enrichment combined with Acid Gas Injection, Xergy Direct Oxidation, non-regenerative treating, Acid Gas Injection and Claus. Note that continuing to flare the acid gas was not an option due to the EUB license requirement to reduce the sulphur emissions. The Claus process was chosen as it had the lowest capital and operating costs of the alternatives being considered.

The base case was a selectox three stage Claus process, and Taylor was contemplating purchasing an existing unit that had been operating for many years. The gas was diverted to another plant for processing and the Claus unit was no longer needed at that facility. The Claus unit would have addressed the required sulphur emissions issue and would have been applicable at this site given the high CO_2 levels in the sour gas stream.

Although a Claus process of a similar capability to the acid gas injection unit would result in over 98% recovery of the hydrogen sulfide as sulphur, there would still be some sulphur dioxide emitted to the atmosphere during normal operation or during non-routine acid gas flaring using sales gas to meet operating permit requirements. Essentially all of the carbon dioxide separated from the natural gas and all of the carbon dioxide produced from fuel gas consumed to operate the Claus plant and to flare the acid gas under upset conditions would have been emitted to the atmosphere.

In addition, the resulting sulphur product from the Claus plant would have had to be handled on site and shipped to markets. This would have resulted in small quantities of emissions of greenhouse gases. Given the difficulty in quantifying these potential emissions, they were not included in the analysis contributing to the conservativeness of this emission reduction calculation.

3.4 ACTIONS TAKEN

To meet the requirement to reduce sulphur emissions at the Turin facility, Taylor chose to implement an acid gas injection program. Under this program, acid gas (greater than 95% carbon dioxide and between 1.5% and 5% hydrogen sulfide) is compressed, using an electric-motor-driven compressor, and transported by pipeline nearly 1.5 kilometers to an injection site in a depleted reservoir. This project thereby reduces sulphur dioxide emissions by 100% of current levels and greatly reduces the effective carbon dioxide emissions from the site.

Taylor chose acid gas injection over more conventional technologies in spite of commercial challenges associated with this technology. As a gas processing company with no oil or gas production assets, Taylor had to negotiate with area gas producers to secure the right to dispose of acid gas in one of their reservoirs. The securing of this right was obtained at a significant cost to Taylor in terms of fee revenue. In addition, acid gas disposal schemes involve a lengthy regulatory approval process. In comparison, conventional technologies would have involved a much quicker approval process and would not have involved negotiations with the producers. Taylor chose acid gas injection as a forward-thinking decision in anticipation of future corporate requirements to reduce sulphur emissions.

In August 2004, Taylor completed construction of the acid gas injection system in place of the installation of a Claus process unit. The infrastructure of each of the main components of the acid gas injection system is summarized below:

- **Compressor** – a 746kW electric compressor was installed to boost the pressure of the acid gas stream for transportation through the pipeline and into the injection well;
- **Pipeline** – a 1.5 km long pipeline was installed to transport the compressed acid gas to the injection reservoir.
- **Injection and Monitoring Infrastructure –** various monitoring instruments were installed along the pipeline to measure system operating parameters and ensure there is no leakage from the on-site infrastructure or from the reservoir. Due to the toxicity of the acid gas, leakage is prevented as per Alberta EUB Approval #9959.

3.5 PROJECT CONDITION

The acid gas injection system commenced operation in 2004. Flaring of acid gas is conducted on an emergency basis only, using an open flare system. Had the Project not been undertaken by Taylor in 2004, sulphur would have been removed using a multi-stage Claus unit.

Details of the three main components of the acid gas injection system project are provided in the sections below.

3.5.1 COMPRESSOR

The compressor is composed of a 746 kW electric motor-driven reciprocating gas compressor skidded module, a chiller/heat exchanger module, and a control module onto new driven steel pile foundations and installed within the boundaries of the existing gas plant. The acid gas is compressed to a pressure of up to 8600 kpa for injection into the selected nearby disposal reservoir, and transported by a new 88.9 mm pipeline. New piping was required to connect the various modules of the injection system. New electrical equipment was also required to serve the system, including a 1 MW transformer and new power lines to the equipment.

3.5.2 Pipeline

The pipeline is an 88.9 mm OD (3” nominal) pipeline running approximately 1.5 km to the injection well location at 03-25-012-19 W4. Terrain is flat, non-irrigated farmland, which presented no unusual risks to pipeline construction.

3.5.3 Injection and monitoring infrastructure

Compressed acid gas is transported by pipeline to a well characterized nearly depleted natural gas reservoir resulting in essentially permanent geological sequestration (>1000 years). Regular reservoir pressure surveys are conducted to ensure that the injected gas is being contained within the target reservoir.

Issuance of the operational permits from the Alberta EUB and Alberta Environment provides assurance that the required measurement and monitoring programs are in place to ensure long-term sequestration of all components of the acid gas stream. In particular, a complete geological assessment of the injection reservoir with respect to permanence of sequestration, an assessment of any potential leakage and contemplation of the leakage mitigation and management strategies that Taylor has implemented was included in the review completed by the Alberta EUB and Alberta Environment for this project activity.

3.6 Inventory of Sources and Sinks

The sources and sinks included for quantification are as follows:

- P8: Upset Flaring
- P12: Fuel Extraction / Processing
- B6: Incineration
- B9: Fuel Extraction / Processing

The quantification of each of these sources is described in further detail in Section 5.3.

3.7 Quantification Protocol Applicability

The applicability criteria, identification of sources and sinks, and quantification methodologies for this project have been determined in accordance with the Alberta Offset System Quantification Protocol for Acid Gas Injection (V1, AENV, May 2008). As outlined in the protocol, the project must conform to the following applicability criteria. This Offset Project Plan must demonstrate that:

1. The sequestration project results in removal of emissions that would otherwise have been released to the atmosphere as indicated by an affirmation from the project developer and project schematics;

2. Where the entities/operations are separate and distinct, the emissions reduced are captured under the protocol and will be reported as being emitted at the source facility such that the emission reductions are not double counted;

3. The Acid Gas injection scheme has obtained approval from the Alberta Energy and Utilities Board (Alberta EUB) and meets the requirements outlined under Directive 051: Injection and Disposal Wells – Well Classifications, Completions, Logging and Testing Requirements;

4. Metering of injected gas volumes takes place as close to the injection point as is reasonable to address the potential for fugitive emissions as demonstrated by a project schematics;

5. The quantification of reductions achieved by the project is based on actual measurement and monitoring (except where indicated in this protocol) as indicated by the proper application of this protocol; and

6. The project must meet the requirements for offset eligibility as specified in the applicable regulation and guidance documents for the Alberta Offset System.

Demonstration that the Project complies with the applicability criteria outlined above is provided in the following sections.

3.7.1 Removal of emissions

In the absence of the acid gas injection system, Taylor would have installed a Claus unit to comply with regulations to reduce sulphur emissions, while continuing to flare the balance of the acid gas stream and releasing all CO_2 contained in the acid gas stream to the atmosphere.

3.7.2 Ownership of Emission reductions

Taylor has acquired ownership of the injection well from Provident and has obtained Provident's consent to operate the injection program. Ownership of the emissions reductions will be assigned to Taylor as part of contractual relationships with each of the gas producers that provide raw natural gas to the processing facility. The two shut in well owners and the two abandoned well owners acknowledge Taylor's ownership of the emission reduction credits.

No other entity is claiming credit for the reductions realized at Taylor's sour gas processing facility. Credits created from the specified reduction activity have not been created, recorded or registered in more than one trading registry for the same time period.

3.7.3 ALBERTA EUB APPROVAL

The Alberta EUB and Alberta Environment have granted licenses for the implementation of an acid gas disposal scheme, #9959 and #9911-01-04 respectively.

3.7.4 FUGITIVE EMISSIONS

Continuous inline flow meters at the well site measure the volume of injected and recycled gas. The injection gas meter is located as close to the injection well as possible to ensure that fugitive emissions are not being over-accounted for in the transportation of acid gas to the injection well. This data is collected and managed in accordance with industry standards.

Alberta EUB issuance of the operational permit (Approval No. 9959) for the acid gas injection system provides assurance that the required measurement and monitoring programs are in place to ensure the long-term sequestration of all components of the acid gas stream, including an assessment of the injection reservoir in terms of permanence of sequestration, any potential leakage, and mitigation and management strategies that Taylor has implemented to ensure that there are no potential leaks.

3.7.5 QUANTIFICATION OF REDUCTIONS

The quantification of reductions achieved by this project is achieved by actual measurement and monitoring, as outlined in section 5.0 of this Offset Project Plan.

3.6.6 OFFSET ELIGIBILITY REQUIREMENTS

This project meets the requirements for offset eligibility as specified in the applicable regulation and guidance documents for the Alberta Offset System. In particular:

- The acid gas injection program began in late 2004, which is after the specified start date of January 1, 2002. The project start date is demonstrated by the commissioning of the acid gas injection system;

- The Project proponent intends to claim offset reductions for an initial period of 8 years, as specified in the Guidance Document. The end of the initial Project offset crediting period is thus set at December 31, 2012; and

- Ownership of the emission reductions has been established. No other entity is claiming credit for the reductions realized at the Turin sour gas processing facility. Credits created from the specified reduction activity have not been created, recorded or registered in more than one trading registry for the same time period.

- The acid gas injection system installed at the facility produces reductions that are real and are not the result of a shutdown or cessation of an activity. The emission reductions are related to the facility's operations and are quantifiable using the provided protocol based on metered and measured data.

- The emission reduction created as a result of the acid gas injection project at the Turin sour-gas processing plant are surplus to any regulation. The regulations which have triggered Taylor's investment in such a project relate only to the sulphur emissions from the facility and not to the greenhouse gas emissions. These approvals are numbered, No. 9959 and No. 9911-01-04 respectively.

3.6 Quantification Protocol Flexibility Mechanisms

The quantification of GHG emission reductions from the Taylor Acid Gas Injection Project utilizes the flexibility mechanism for site specific emission factors from the Quantification Protocol for Acid Gas Injection (Version 1, May 2008).

As defined in the Protocol's third flexibility mechanism, site specific emission factors may be substituted for the generic emission factors indicated in the protocol document. The methodology for generation of these emission factors must be sufficiently robust as to ensure reasonable accuracy.

In this project, the default Environment Canada CO_2 emission factor for fuel gas combustion was replaced with a site specific emission factor calculated according to the specific composition of the fuel gas used at the site. The use of semi-annual third party lab analyses to calculate the carbon content of the fuel gas improves the accuracy of the quantification. The methodology for the calculation of the fuel gas emission factor was sourced from best practice guidance from the Canadian Association of Petroleum Producers (CAPP), shown below.

$$[(a+2b + 3c + 4d + 5e + f) \times 44.01]/23.64 = \text{kg } CO_2/m^3 \text{ fuel burned}$$

Where

a to f = mole fractions of natural gas components (a=C1, b=C2, c=C3, etc).
44.01 = molecular weight of CO_2
23.64 = volume in m^3 occupied by 1 kmole of gas at 15°C and 101.3 kPa

4 Identification and Justification of Baseline

Reductions are calculated from a theoretical baseline of the emissions that would have been emitted with the operation of a three bed (three stage) Claus sulphur treatment process unit. These emissions are calculated using the Alberta Offset System Acid Gas Injection Protocol. Engineering specifications were developed to scope the operations of this facility. The operations of the facility, including gas processing and compression activities that are not a part of the acid gas injection system, are functionally equivalent between the project and baseline condition and therefore omitted from calculations.

The baseline scenario for this protocol is dynamic as the volume of gas injected would be expected to change materially from project to project.

5 QUANTIFICATION OF EMISSION REDUCTIONS

5.1 PROCESS DESCRIPTION

The following three equations serve as the basis for calculating the emission reductions from the comparison of the baseline and project conditions:

$$\text{Emission Reduction} = \text{Emissions}_{\text{Baseline}} - \text{Emissions}_{\text{Project}}$$

$$\text{Emissions}_{\text{Baseline}} = \text{Emissions}_{\text{Fuel Extraction and Processing}} + \text{Emissions}_{\text{Multi-Stage Claus Unit}} + \text{Emissions}_{\text{Incineration}}$$

$$\text{Emissions}_{\text{Project}} = \text{Emissions}_{\text{Fuel Extraction and Processing}} + \text{Emissions}_{\text{Gas Dehydration and Compression}} + \text{Emissions}_{\text{Upset Flaring}} + \text{Emissions}_{\text{Injection Unit Operation}} + \text{Emissions}_{\text{Recycled Gas}}$$

Emissions Baseline = sum of the emissions under the baseline condition.

Emissions $_{\text{Fuel Extraction and Processing}}$ = emissions under SS B9 Fuel Extraction / Processing

Emissions $_{\text{Multi-Stage Claus Unit}}$ = emissions under SS B5 Multi-Stage Claus Unit

Emissions $_{\text{Incineration}}$ = emissions under SS B6 Incineration

Emissions Project = sum of the emissions under the project condition.

Emissions $_{\text{Fuel Extraction and Processing}}$ = emissions under SS P12 Fuel Extraction / Processing

Emissions $_{\text{Gas Dehydration and Compression}}$ = emissions under SS P6 Acid Gas Dehydration and Compression

Emissions $_{\text{Upset Flaring}}$ = emissions under SS P8 Upset Flaring

Emissions $_{\text{Injection Unit Operation}}$ = emissions under SS P9 Injection Unit Operation

Emissions $_{\text{Recycled Gas}}$ = emissions under SS P10 Recycled Gas

The details of the parameters used in the equations are presented in the table in Appendix A.

5.2 Data Sources

As Table 5.3.1 demonstrates, the data required for calculation of the emission reduction generated by the Project consists of the following:

- Volume of fossil fuels consumed for fuel extraction and processing;
- Volume of fossil fuels consumed for injection unit operation and flaring in the project condition. This includes the volume of fuel combusted for acid gas dehydration and compression, upset flaring and injection unit operation not powered by electricity;
- Volume of fossil fuels consumed from Claus unit operation in the baseline condition. This includes the volume of fuel combusted for Claus unit operation if not powered by electricity and flaring;
- Volume of fossil fuels consumed to supplement the flare in the baseline condition;
- Volume of acid gas injected;
- Volume of acid gas flared in the project condition;
- Volume of acid gas flared in the baseline condition;
- Volume of recycled acid gas (carbon dioxide) produced at gas wells within the same reservoir;
- Composition of injected acid gas (%CO_2, %CH_4, %H_2S and trace compounds by volume);
- Composition of fuel gas (%CO_2, %CH_4, and trace compounds by volume);
- Heat value of fuel gas used to supplement the flare.

In addition the following variables based on project engineering design documents from a Sulsim simulation run for the Claus process are required to estimate the baseline:

- Process energy recovered;
- Heat transfer efficiency;
- Fuel energy efficiency;
- Realized energy density from each type of fuel;

- Heat value of tail gas.

The specific methods of quantification for the above data sources are presented in the following section.

5.3 QUANTIFICATION PLAN

Quantification of the emission reductions generated by the project will be conducted using the Calculator developed by Blue Source along with the Quantification Protocol for Acid Gas Injection (AENV, 2008). The general methods of quantification for the required data listed above are as follows:

- **Volume of fossil fuels consumed for fuel extraction and processing -** fossil fuels will be consumed for upset flaring and incineration in the baseline resulting in GHG emissions. As sales gas is the fossil fuel consumed in the project and baseline, emission factors for extraction and processing of natural gas will be used as a conservative emissions factor. The quantities and types of each energy input need to be tracked. The volumes of fossil fuels consumed are determined from direct metering or reconciliation of volume in storage.
- **Volume of fossil fuels consumed for Injection unit operation and flaring in the project condition** –Acid gas may need to be flared during upset conditions or during maintenance resulting in GHG emissions and fuel gas will be required to supplement the flare.
  - The acid gas injection unit and compressor are electric and there are no fossil fuels associated with its use.
  - Volumes of fuel gas used to supplement the acid gas flare are determined through direct metering.
- **Volume of fossil fuels consumed from Claus unit operation in the baseline condition –** fossil fuels will be consumed for the operation of the Claus unit in the baseline condition. Indirect emissions from electricity used by the Claus unit are not included for conservativeness. Oxidation of H_2S in the Claus process is an exothermic reaction, and in the case of the acid gas at Turin, the H_2S content is very lean at around 2%, with the net heat evolved or required from the process being very close to zero.
  - Engineering reports for the proposed Claus unit show an average of approximately 43 MJ/hr or 1 GJ/day of net heat evolved from the process. This heat would be captured in the circulating hot oil system and would be used to offset gas consumption in the hot oil heaters. This equates to a gas consumption rate of -0.03 e^3m^3/day from engineering reports. As this value is negligible and has a negligible impact on the emissions from the

baseline scenario, it is assumed that the fuel required by the Claus process equals 0 e^3m^3/day. As such, no fossil fuels are consumed by the Claus unit.

- **Volume of fossil fuels consumed to supplement the flare in the baseline condition** - fossil fuels will be required to supplement flaring in the baseline. The volume of sales gas required to supplement the flare at full operation is estimated from the heat values of the tail gas, combined gas and fuel gas used to supplement the flare and the total volume of acid gas produced (see Appendix A). The total volume of acid gas produced is the sum of the volume of acid gas flared and the volume of acid gas injected.

- **Volume of acid gas injected –** acid gas is injected into the reservoir by the acid gas injection system, and will be measured by inline flow meters.

- **Volume of acid gas flared in the project condition –** flaring of acid gas may be required during upset conditions or during system maintenance of upstream processing elements. GHG emissions would result from the carbon dioxide and methane contained in the acid gas. The volume of acid gas flared under the project condition is measured continuously and summed on a monthly and then annual basis for the required calculations.

- **Volume of acid gas flared in the baseline condition –** residual acid gas not recovered during the Claus process would need to be flared along with CO_2 remaining after the Claus process. GHG emissions would result from the GHG content of the acid gas. The volume of acid gas flared under the baseline condition is measured continuously as the total volume of acid gas produced in the project condition.

- **%CO_2 and %CH_4 by volume in acid gas[1]** – the composition of the acid gas stream is sampled continuously by a gas chromatograph.

  - Continuously monitored mole fractions of CH_4 and CO_2 in acid gas were averaged on a monthly basis automatically by the chromatograph. These values were entered into the quantification calculator.

- **%CO_2, %CH_4, and trace hydrocarbons by volume in fuel gas** – a gas composition analysis is completed semi-annually by an independent third party. These are averaged for the yearly gas composition. This is appropriate as the

[1] Note that small amounts of other hydrocarbons are present in the acid gas stream that is injected; however, for consistency with the Alberta Offset System Quantification Protocol for Acid Gas Injection, the CO_2 emissions from combustion of these trace hydrocarbon compounds are not included in the baseline calculation for flaring under SS B6.

fuel gas used to supplement the flare is sales gas, which has a consistent pipeline specification.

- **Heat value of fuel gas used to supplement the flare –** the heat value of the fuel gas used to supplement the flare is an average from the semi-annual gas composition analyses. This is appropriate as the fuel gas used to supplement the flare is sales gas, which has a consistent pipeline specification.

Variables based on project engineering design documents:

- **Process Energy Recovered** – this parameter is determined from the output of the Sulsim simulation run for the proposed Claus process. From the simulation run report the overall heat balance is negative, which means a heat input is required to run the unit.

- **Heat transfer efficiency** - this parameter is determined from Project engineering design documents for the proposed Claus process.

- **Fuel energy efficiency –** this parameter is determined from the output of the Sulsim simulation run for the proposed Claus process.

- **Realized energy density from each type of fuel** - this parameter is determined from project engineering reports that specify the energy density of each type of fuel being offset in other processes.

- **Heat value of tail gas** - this parameter is determined from project engineering reports that specify the expected tail gas heat value for an appropriately sized multi-stage Claus unit. This value was calculated using the expected molar percent composition of the tail gas and heating values for each component.

Detailed descriptions of the quantification methods for the required data, excluding those obtained from engineering design documents and Sulsim simulations for the Claus unit are provided in Table 5.3.1 below.

Table 5.1: Quantification Methods

Required data	Project-specific data	Measurement method	Measurement Frequency	Meter ID	Quantification Method
Volume of fossil fuels consumed in the project condition	Volume of fuel gas used for upset flaring.	Direct metering or reconciliation of volume in storage. The volume of fuel gas used is calculated based on the volume of gas flared and the heat values of the fuel gas, tail gas and combined gas streams.	Continuous metering or monthly reconciliation.	151	Manual entry of monthly totals into the Quantification Calculator.
Volume of fossil fuels consumed to supplement the flare in the baseline / Volume of acid gas flared in the baseline	Volume of acid gas produced.	Sum of volume of acid gas flared, volume of acid gas injected minus volume of recycled acid gas produced.	Continuous metering or monthly reconciliation.	3, 3A	Manual entry of monthly totals into the Quantification Calculator.
Volume of acid gas injected	Volume of acid gas injected	Direct metering.	Continuous metering or monthly reconciliation.	3A	Manual entry of monthly totals into the Quantification Calculator.
Mole fractions of CO_2 and CH_4 in injected acid gas	Composition of the acid gas stream.	Calculation based on monthly consolidation of continuous measurements.	Continuous	N/A	Manual entry of monthly averages into the Quantification Calculator.
Volume of acid gas flared in the project condition	Volume of acid gas flared during upset flaring.	Direct metering.	Continuous metering.	3	Manual entry of monthly totals into the Quantification Calculator.
Volume of recycled acid gas produced at wells within the same reservoir	Volume of acid gas produced at wells within the same reservoir.	The producing well within the same reservoir produced acid gas until March 2007. After this point all wells were shut in so no acid gas was produced.	N/A	N/A	Manual entry of monthly data collected into the Quantification Calculator.

Required data	Project-specific data	Measurement method	Measurement Frequency	Meter ID	Quantification Method
Carbon dioxide contained in recycled acid gas produced at wells within the same reservoir	Composition of the acid gas stream produced at wells within the same reservoir.	The producing well within the same reservoir produced acid gas until March 2007. After this point all wells were shut in so no acid gas was produced.	Monthly	N/A	Manual entry of monthly average into the Quantification Calculator.
Mole fractions of CO_2, CH_4, and trace hydrocarbons in fuel gas	Fuel gas composition analysis	Measurement by independent third party	Semi-annual	N/A	Manual entry of yearly average into Quantification Calculator.
Heat value of fuel gas used to supplement the flare	Heat value of fuel gas used to supplement the flare.	Measurement by independent third party as part of gas analysis	Semi-annual calculation from TransCanada's composition data for the sales gas from the Turin plant.	N/A	Manual entry of annual average heat value into the Quantification Calculator.

5.4 Monitoring and Quality Assurance/Quality Control (QA/QC) Plan

In general, the data control process employed for this Project consists of manual or metered data capture and reporting and the use of circular charts to record data, and manual entry of monthly total or average values into a Quantification Calculator developed by Blue Source.

There are two data streams involved in this project:

- Flow data reported using circular charts;
- Data captured and reported by the Turin metering systems; and
- Manual data entry of fossil fuel volumes.

The specifics of the Monitoring and QA/QC plan are discussed in the following sections.

5.4.1 Metering Maintenance and Calibration and QA/QC Program

Monitoring and QA/QC for the metering systems used at the Turin facility consists of a maintenance and calibration program designed to ensure the accuracy of the data collection system. The details of maintenance and calibration for each meter used in the collection of data for emission reduction calculations are provided in Table 5.4.1

Table 5.2: Metering Maintenance and Calibration Details

Project Specific Data	Meter ID	Meter Make/Model	Maintenance Schedule	Calibration Schedule	Accuracy Rating
Volume of sales gas consumed.	4	Barton 202A	6 months or as required	6 months	Less than 5% difference
Volume of fuel gas used for upset flaring.	151	Barton 220A	6 months or as required	6 months	Less than 5% difference
Volume of acid gas produced.	3, 3A	Barton 220A, Barton 242AC	6 months or as required	6 months	Less than 5% difference
Volume of acid gas injected.	3A	Barton 202A	6 months or as required	6 months	Less than 5% difference
Volume of acid gas flared during upset flaring.	3	Barton 242AC	6 months or as required	6 months	Less than 5% difference
Volume of acid gas produced at wells within the same reservoir.	N/A	N/A	N/A	N/A	N/A
Composition of the acid gas stream.	N/A	Rosemount Analytical Gas Chromatograph	6 months or as required	6 months or as required	N/A
Composition of the acid gas stream produced at wells within the same reservoir.	N/A	N/A	N/A	N/A	N/A

Project Specific Data	Meter ID	Meter Make/Model	Maintenance Schedule	Calibration Schedule	Accuracy Rating
Heat value of fuel gas used to supplement the flare.	N/A	N/A	N/A	N/A	N/A

5.4.2 *Manual Checking of Calculator Data*

The quantification of the volume of natural gas used is completed manually, and is based on monthly reconciliation of data collected. Monitoring and QA/QC for natural gas volumes will consist of manual checking of data entered into the Quantification Calculator against the original flow meter data to ensure independent review of the data prior to verification.

Similarly, the use of the Quantification Calculator involves manual entry of monthly totals and averages into the Quantification Calculator. Manual checking of this data will be conducted on an annual basis to ensure independent review of the data prior to verification.

Manual checking will be conducted on an annual basis by Blue Source Canada and will consist of:

- Reconciliation of values in the calculator with hard-copy records of data and circular charts;
- Comparison with data from other time periods to identify any major discrepancies (“reality checking”); and
- Recalculation of selected values to ensure that the Calculator remains accurate.

5.4.3 *Record Keeping*

Record keeping practices for the project consist of:

- Circular charts for recording of values of logged primary parameters for each measurement interval;
- Printing of monthly back-up hard copies of all logged data;
- Written logs of operations and maintenance of the project system including notation of all shut-downs, start-ups and process adjustments;
- Retention of copies of logs and all logged data for a period of 7 years; and
- Keeping all records available for review by a verification body.

6 Reporting of Emission Reductions

Emission reductions achieved through this Project from the project start date to the end of 2012 will be claimed starting January 1st, 2007. After the initial emissions reduction claim, emissions reductions will be claimed on an annual basis and quantified in accordance with the calculation methodology described in the Alberta Offset System Quantification Protocol for Acid Gas Injection Version 1.0 (AENV, 2008). Emissions reductions will be verified by a third-party verifier according to the Guidance Document provided by AENV.

APPENDIX A

CALCULATION PARAMETERS

Table 6.1: Quantification Procedures

1.0 Project/Baseline SS	2. Parameter / Variable	3. Unit	4. Measured / Estimated	5. Method	6. Frequency	7. Justify measurement or estimation and frequency
Project SS's						
P12 Fuel Extraction / Processing	Emissions $_{Fuel\ Extraction\ and\ Processing}$ = Σ (Vol. Fuel $_I$ * EF Fuel $_{i\ CO2}$) ; Σ (Vol. Fuel $_I$ * EF Fuel $_{i\ CH4}$) ; Σ (Vol. Fuel $_I$ * EF Fuel $_{i\ N2O}$) ;					
	Emissions $_{Fuel\ Extraction\ /\ Processing}$	kg of CO_2; CH_4 ; N_2O	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel use on site is likely aggregated for each of these SS's.
	Volume of Each Type of Fuel Combusted for P6 to P9 / Vol. Fuel $_i$	L / m^3 / other	Measured	Direct metering or reconciliation of volume in storage (including volumes received).	Continuous metering or monthly reconciliation	Both methods are standard practice. Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence.
	CO_2 Emission Factor for Fuel Extraction and Processing / EF Fuel $_{i\ CO2}$	kg CO_2 per L / m^3 / other	Estimate	From Environment Canada reference documents.	Annual	Reference values adjusted annually as part of Environment Canada's emissions inventory.
	CH_4 Emissions Factor for Fuel Extraction and Processing / EF Fuel $_{i\ CH4}$	kg CH_4 per L / m^3 / other	Estimate	From Environment Canada reference documents.	Annual	Reference values adjusted annually as part of Environment Canada's emissions inventory.
	N_2O Emissions Factor for Fuel Extraction and Processing / EF Fuel $_{i\ N2O}$	kg N_2O per L / m^3 / other	Estimate	From Environment Canada reference documents.	Annual	Reference values adjusted annually as part of Environment Canada's emissions inventory.
P6 Acid Gas	Emissions $_{Gas\ Dehydration\ and\ Compression}$ = Σ (Vol. Fuel $_i$ * EF Fuel $_{i\ CO2}$) ; Σ (Vol. Fuel $_i$ * EF Fuel $_{i\ CH4}$) ; Σ (Vol. Fuel $_i$ * EF Fuel $_{i\ N2O}$)					

1.0 Project/Baseline SS	2. Parameter / Variable	3. Unit	4. Measured / Estimated	5. Method	6. Frequency	7. Justify measurement or estimation and frequency
Dehydration and Compression	Emissions $_{Gas\ Dehydration\ and\ Compression}$	kg of CO_2; CH_4 ; N_2O	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel use on site is likely aggregated for each of these SS's.
	Volume of Each Type of Fuel Used / Vol. Fuel $_i$	L / m^3 / other	0	N/A	N/A	Volume of fuel used is zero as the compressor is electric.
	CO_2 Emissions Factor for Each Type of Fuel / EF Fuel $_{i\ CO2}$	kg CO_2 per L / m^3 / other	Estimate	Calculated using fuel gas composition as per Flexibility Mechanism in Section 3.6	Annual	Use of site specific emission factor provides a higher level of accuracy than the use of default emission factors.
	CH_4 Emissions Factor for Each Type of Fuel / EF Fuel $_{i\ CH4}$	kg CH_4 per L / m^3 / other	Estimate	From Environment Canada reference documents.	Annual	Reference values adjusted annually as part of Environment Canada's emissions inventory.
	N_2O Emissions Factor for Each Type of Fuel / EF Fuel $_{i\ N2O}$	kg N_2O per L / m^3 / other	Estimate	From Environment Canada reference documents.	Annual	Reference values adjusted annually as part of Environment Canada's emissions inventory.
P8 Upset Flaring	Emissions $_{Flaring}$ = (Vol. AG Flared * % CO_2 * ρ_{CO2}); (Vol. AG Flared * % CH_4 * ρ_{CH4} * 44/16); Σ (Vol. Fuel $_i$ * EF Fuel $_{i\ CO2}$) ; Σ (Vol. Fuel $_i$ * EF Fuel $_{i\ CH4}$) ; Σ (Vol. Fuel $_i$ * EF Fuel $_{i\ N2O}$)					
	Emissions $_{Flaring}$	Kg of CO_2 ; CH_4 ; N_2O	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel use on site is likely aggregated for each of these SS's.

1.0 Project/Baseline SS	2. Parameter / Variable	3. Unit	4. Measured / Estimated	5. Method	6. Frequency	7. Justify measurement or estimation and frequency
	Volume of Acid Gas Flared / Vol. AG Flared	m^3	Measured	Direct metering of volume of AG being flared	Continuous metering	Direct metering is standard practice. Frequency of metering is highest level possible.
	Carbon Dioxide Composition in AG / % CO_2	%	Measured	Direct measurement	Daily sampling averaged monthly on a volumetric basis	Acid gas composition should remain relatively stable during steady-state operation. Frequency of sampling provides for reasonable diligence.
	Density of CO_2 / ρ_{CO2}	kg / m^3	Constant	1.86 kg/m^3 at 15°C and 1 Atmosphere[2]	N/A	Accepted value
	CH_4 Composition in AG / % CH_4	%	Measured	Direct measurement	Continuous metering or monthly sampling on a volumetric basis	Acid gas composition should remain relatively stable during steady-state operation. Frequency of sampling provides for reasonable diligence.
	Density of CH_4 / ρ_{CH4}	kg/m^3	Constant	0.68 kg/m^3 at 15°C and 1 Atmosphere[3]	N/A	Accepted value

[2] Note that the volume of acid gas is metered at industry standard conditions of 15°C and 1 atmosphere and therefore the corresponding densities for CO_2 and methane at these conditions was used in place of the densities at STP (0°C and 1 atmosphere), prescribed by the protocol.
[3] Ibid

1.0 Project/Baseline SS	**2. Parameter / Variable**	**3. Unit**	**4. Measured / Estimated**	**5. Method**	**6. Frequency**	**7. Justify measurement or estimation and frequency**
	Volume of Each Type of Fuel used to Supplement Flare / Vol Fuel $_i$	L / m^3 / other	Measured	Direct metering or reconciliation of volume in storage (including volumes received).	Continuous metering or monthly reconciliation.	Both methods are standard practice. Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence.
	CO_2 Emissions Factor for Each Type of Fuel / EF Fuel $_{i\ CO2}$	kg CO_2 per L / m^3 / other	Estimate	Calculated using fuel gas composition as per Flexibility Mechanism in Section 3.6	Annual	Use of site specific emission factor provides a higher level of accuracy than the use of default emission factors.
	CH_4 Emissions Factor for Each Type of Fuel / EF Fuel $_{i\ CH4}$	kg CH_4 per L / m^3 / other	Estimate	From Environment Canada reference documents.	Annual	Reference values adjusted annually as part of Environment Canada's emissions inventory.
	N_2O Emissions Factor for Each Type of Fuel / EF Fuel $_{i\ N2O}$	kg N_2O per L / m^3 / other	Estimate	From Environment Canada reference documents.	Annual	Reference values adjusted annually as part of Environment Canada's emissions inventory.
P9 Injection Unit Operation	Emissions $_{\text{Injection Unit Operatoin}}$ = Σ (Vol. Fuel $_i$ * EF Fuel $_{i\ CO2}$) ; Σ (Vol. Fuel $_i$ * EF Fuel $_{i\ CH4}$) ; Σ (Vol. Fuel $_i$ * EF Fuel $_{i\ N2O}$)					
	Emissions $_{\text{Injection Unit Opertiona}}$	kg of CO_2; CH_4 ; N_2O	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel use on site is likely aggregated for each of these SS's.

1.0 Project/Baseline SS	2. Parameter / Variable	3. Unit	4. Measured / Estimated	5. Method	6. Frequency	7. Justify measurement or estimation and frequency
	Volume of Each Type of Fuel Used / Vol. $Fuel_i$	L / m^3 / other	0	N/A	N/A	Volume of fuel used is zero as the acid gas injection unit is electric.
	CO_2 Emissions Factor for Each Type of Fuel / EF Fuel $_{i\ CO2}$	kg CO_2 per L / m^3 / other	Estimate	Calculated using fuel gas composition as per Flexibility Mechanism in Section 3.6	Annual	Use of site specific emission factor provides a higher level of accuracy than the use of default emission factors.
	CH_4 Emissions Factor for Each Type of Fuel / EF Fuel $_{i\ CH4}$	kg CH_4 per L / m^3 / other	Estimate	From Environment Canada reference documents.	Annual	Reference values adjusted annually as part of Environment Canada's emissions inventory.
	N_2O Emissions Factor for Each Type of Fuel / EF Fuel $_{i\ N2O}$	kg N_2O per L / m^3 / other	Estimate	From Environment Canada reference documents.	Annual	Reference values adjusted annually as part of Environment Canada's emissions inventory.
P10 Recycled Gas	$Emissions_{Recycled\ Gas} = \Sigma (Vol._{Recycled\ Gas} * \%\ CO_2 * \rho_{CO2})$					
	Emissions $_{Recycled\ Gas}$	kg CO_2	N/A	N/A	N/A	Quantity being calculated.
	Volume of Gas Produced at Wells Within the Same Reservoir / Vol. $_{Adjacent\ Gas}$	m^3	Measured	Not applicable. The last remaining producing well was shut-in in March 2007.	Continuous metering	Direct metering is standard practice. Frequency of metering is highest level possible.

1.0 Project/Baseline SS	2. Parameter / Variable	3. Unit	4. Measured / Estimated	5. Method	6. Frequency	7. Justify measurement or estimation and frequency
	CO_2 Composition in Adjacent Gas / % CO_2	%	Measured	Not applicable. The last remaining producing well was shut-in in March 2007.	Monthly sampling	Gas composition should remain relatively stable during steady-state operation. Frequency of reconciliation provides for reasonable diligence.
	Density of CO_2 / ρ_{CO2}	kg/m^3	Constant	1.86 kg/m^3 at 15°C and 1 Atmosphere	N/A	Accepted value
Baseline SS's						
B9 Fuel Extraction / Processing	Emissions $_{Fuel\ Extraction\ and\ Processing}$ = Σ (Vol. Fuel $_I$ * EF Fuel $_{i\ CO2}$) ; Σ (Vol. Fuel $_I$ * EF Fuel $_{i\ CH4}$) ; Σ (Vol. Fuel $_I$ * EF Fuel $_{i\ N2O}$) ;					
	Emissions $_{Fuel\ Extraction\ and\ Processing}$	kg of CO_2; CH_4 ; N_2O	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel use on site is likely aggregated for each of these SS's.
	Volume of Each Type of Fuel Combusted for B5 / Vol. Fuel $_i$	L / m^3 / other	Measured	Direct metering or reconciliation of volume in storage (including volumes received).	Continuous metering or monthly reconciliation	Both methods are standard practice. Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence.
	CO_2 Emissions Factor for Fuel Extraction and Processing / EF Fuel $_{i\ CO2}$	kg CO_2 per L / m^3 / other	Estimate	From Environment Canada reference documents.	Annual	Reference values adjusted annually as part of Environment Canada's emissions inventory.

1.0 Project/Baseline SS	2. Parameter / Variable	3. Unit	4. Measured / Estimated	5. Method	6. Frequency	7. Justify measurement or estimation and frequency
	CH_4 Emissions Factor for Fuel Extraction and Processing / EF Fuel $_{i\ CH4}$	kg CH_4 per L / m^3 / other	Estimate	From Environment Canada reference documents.	Annual	Reference values adjusted annually as part of Environment Canada's emissions inventory.
	N_2O Emissions Factor for Fuel Extraction and Processing / EF Fuel $_{i\ N2O}$	kg N_2O per L / m^3 / other	Estimate	From Environment Canada reference documents.	Annual	Reference values adjusted annually as part of Environment Canada's emissions inventory.
B5b Multi-Stage Claus Unit	Emissions $_{Multi\text{-}Stage\ Claus\ Unit}$ = Σ (Vol. Fuel $_i$ - ((E $_{Claus}$ * η $_{Heat}$) / (η $_{Energy}$ * ω $_{Fuel\ i}$))) * EF Fuel $_{i\ CO2}$) ; Σ(Vol. Fuel $_i$ - ((E $_{Claus}$ * η $_{Heat}$) / (η $_{Energy}$ * ω $_{Fuel\ i}$))) * EF Fuel $_{i\ CH4}$) ; Σ (Vol. Fuel $_i$ - ((E $_{Claus}$ * η $_{Heat}$) / (η $_{Energy}$ * ω $_{Fuel\ i}$))) * EF Fuel $_{i\ N2O}$)					
	Emissions $_{Multi\text{-}Stage\ Claus\ Unit}$	kg of CO_2; CH_4 ; N_2O	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel use on site is likely aggregated for each of these SS's.
	Volume of Each Type of Fuel Used / Vol. Fuel$_i$	Vol. Fuel$_i$ = Fuel $_{Claus}$ * % Vol. Cap * # of days * Hrs Avail.				
		L / m^3 / other	Calculation	Project Engineering Design	Project Definition	Quantity being calculated.
		Claus Fuel Requirement / Fuel $_{Claus}$	Estimate	Project Engineering Design	0 e^3m^3/d	The engineering report specifies the volume of fuel gas required for an appropriately sized Multi-Stage Claus Unit. Represents most reasonable means of estimation. In addition, electricity required for Claus unit operation does not need to be tracked.

1.0 Project/Baseline SS	2. Parameter / Variable	3. Unit	4. Measured / Estimated	5. Method	6. Frequency	7. Justify measurement or estimation and frequency
		% Volumetric capacity of facility / % Vol. Cap	Measured	Calculation	Monthly	The monthly total volume of acid gas produced divided by the number of days in the month will specify the capacity utilized for the month. The capacity utilized divided by the licensed capacity of 85 e^3m^3/d will specify the volumetric capacity.
		# of days in month being calculated / # of days	N/A	N/A	Monthly	The number of days in the month being calculated will be used to determine the monthly fuel requirement.
		Hours Equipment is available / Hrs avail.	Estimate	Project Engineering Design	Project Definition	The engineering report specifies the number of hours the equipment will be operational as 99% of the time.
	Process Energy Recovered / E_{Claus}	GJ	Estimate	Project Engineering Design	Project Definition	The Sulsim simulation process report will specify the exothermic energy recovered by an appropriately sized Multi-Stage Claus Unit. Represents most reasonable means of estimation.
	Heat Transfer Efficiency / η_{Heat}	-	Estimate	Project Engineering Design	Project Definition	Engineering report will specify the heat design heat transfer efficiency from an appropriately sized Multi-Stage Claus Unit to another process with heat requirements. Represents most reasonable means of estimation.

1.0 Project/Baseline SS	2. Parameter / Variable	3. Unit	4. Measured / Estimated	5. Method	6. Frequency	7. Justify measurement or estimation and frequency
	Fuel Energy Efficiency / η_{Energy}	-	Estimate	Project Engineering Design	Project Definition	Engineering report will specify the fuel energy efficiency of the secondary process. Represents most reasonable means of estimation.
	Realized Energy Density from Each Type of Fuel / $\omega_{Fuel\ i}$	GJ / m^3	Estimate	Project Engineering Design	Project Definition	Engineering report will specify the energy density of each type of fuel being offset in other processes. Represents most reasonable means of estimation.
	CO_2 Emissions Factor for Each Type of Fuel / EF Fuel $_{i\ CO2}$	kg CO_2 per L / m^3 / other	Estimate	Calculated using fuel gas composition as per Flexibility Mechanism in Section 3.6	Annual	Use of site specific emission factor provides a higher level of accuracy than the use of default emission factors.
	CH_4 Emissions Factor for Each Type of Fuel / EF Fuel $_{i\ CH4}$	kg CH_4 per L / m^3 / other	Estimate	From Environment Canada reference documents.	Annual	Reference values adjusted annually as part of Environment Canada's emissions inventory.
	N_2O Emissions Factor for Each Type of Fuel / EF Fuel $_{i\ N2O}$	kg N_2O per L / m^3 / other	Estimate	From Environment Canada reference documents.	Annual	Reference values adjusted annually as part of Environment Canada's emissions inventory.
B6 Incineration	Emissions $_{Incineration}$ = (Vol. Gas Flared * % CO_2 * ρ_{CO2}); (Vol. Gas Flared * % CH_4 * ρ_{CH4} * 44/16); (((Vol. Gas Flared) * ($HV_{combined}$ – HV_{tail})/(HV_{fuel} – $HV_{combined}$)) * EF Fuel $_{i\ CO2}$) ; (((Vol. Gas Flared) * ($HV_{combined}$ – HV_{tail})/(HV_{fuel} – $HV_{combined}$))* EF Fuel $_{i\ CH4}$) ; (((Vol. Gas Flared) * ($HV_{combined}$ – HV_{tail})/(HV_{fuel} – $HV_{combined}$)) * EF Fuel $_{i\ N2O}$) ;					

1.0 Project/Baseline SS	2. Parameter / Variable	3. Unit	4. Measured / Estimated	5. Method	6. Frequency	7. Justify measurement or estimation and frequency
	Emissions Incineration	kg CO_2 ; CH_4 ; N_2O	N/A	N/A	N/A	Quantity being calculated in aggregate form as fuel use on site is likely aggregated for each of these SS's.
	Volume of Gas Flared / Vol. Gas Flared	m^3	Measured	Direct metering of volume of acid gas produced in the project condition.	Continuous metering.	Direct metering is standard practice. Frequency of metering is the highest level possible.
	CO_2 Composition in Gas / % CO_2	%	Measured	Direct measurement	Weekly sampling averaged monthly on a volumetric basis	Gas composition should remain relatively stable during steady-state operation. Frequency of reconciliation provides for reasonable diligence.
	Density of CO_2 / ρ_{CO2}	kg / m^3	Constant	1.86 kg/m^3 at 15°C and 1 Atmosphere	N/A	Accepted value
	CH_4 Composition in AG / % CH_4	%	Measured	Direct measurement	Continuous metering or monthly sampling on a volumetric basis	Acid gas composition should remain relatively stable during steady-state operation. Frequency of sampling provides for reasonable diligence.
	Density of CH_4 / ρ_{CH4}	kg/m^3	Constant	0.68 kg/m^3 at 15°C and 1 Atmosphere	N/A	Accepted value

1.0 Project/Baseline SS	2. Parameter / Variable	3. Unit	4. Measured / Estimated	5. Method	6. Frequency	7. Justify measurement or estimation and frequency
	Heat Value of Tail Gas / HV_{tail}	MJ / m^3	Estimated	0.41 MJ / m^3	Project Definition	Gas composition should remain relatively stable during steady-state operation. Engineering report specifies the expected tail gas heat value for an appropriately sized multi-stage Claus unit using molar percentage composition and heating values.
	Heat Value of Fuel Gas used to Supplement Flare / HV_{fuel}	MJ / m^3	Measured	Calculated from composition data for the sales gas from the Turin plant.	Monthly	Gas composition should remain relatively stable during steady-state operation. Frequency of reconciliation provides for reasonable diligence.
	Heat Value of Combined Tail Gas and Fuel Gas / $HV_{combined}$	MJ / m^3	Constant	20 MJ / m^3	N/A	Minimum value required by Alberta EUB Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting (November 2006).
	CO_2 Emissions Factor for Each Type of Fuel $_{i\ CO2}$	kg CO_2 per L / m^3 / other	Estimate	Calculated using fuel gas composition as per Flexibility Mechanism in Section 3.6	Annual	Use of site specific emission factor provides a higher level of accuracy than the use of default emission factors.
	CH_4 Emissions Factor for Each Type of Fuel $_{i\ CH4}$	kg CH_4 per L / m^3 / other	Estimate	From Environment Canada reference documents.	Annual	Reference values adjusted annually as part of Environment Canada's emissions inventory.

1.0 Project/Baseline SS	**2. Parameter / Variable**	**3. Unit**	**4. Measured / Estimated**	**5. Method**	**6. Frequency**	**7. Justify measurement or estimation and frequency**
	N_2O Emissions Factor for Each Type of Fuel $_{i\ N2O}$	kg N_2O per L / m^3 / other	Estimate	From Environment Canada reference documents.	Annual	Reference values adjusted annually as part of Environment Canada's emissions inventory.