2012

January

Bonavista Acid Gas Injection at South Rosevear Project Plan

Preferred Carbon Land Management Solutions

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1 Introduction

The Bonavista Acid Gas Injection (AGI) Project at the South Rosevear Gas Plant is the continuation of an AGI based greenhouse gas (GHG) reduction project that originated with Suncor Energy Oil and Gas Partnership and began operation on March 5, 2007. GHG offsets from this project were claimed and listed on the Alberta Emissions Offset Registry (AEOR) for the period ending December 31, 2009 by Suncor Energy[1]. For the period beginning January 1, 2010 through December 31, 2011, the South Rosevear Facility and related AGI Project came under the management of its new majority owner, Bonavista Petroleum.

The AGI project replaced a pre-existing sulfur recovery unit (SRU) based on a multi-stage Claus process which emitted CO_2 and required significant amounts of fossil fuels to be consumed in the safe incineration of the resultant tail gases. The AGI project reduces GHG emissions through the permanent geological sequestration of the CO_2 in the acid gas stream and the significant reduction in the fossil fuel consumption related to the incineration of the SRU's tail gas stream.

The acid gas composed of mainly CO_2 and H_2S is the result of the processing of sour natural gas. The acid gas is compressed, dehydrated, and moved via pipeline to a single injection well in the well-characterized Beaverhill B Pool. The AGI Project is permitted by the Energy Resources Conservation Board (ERCB) originally under Approval No. 10738 later amended under Approval No. 10738A and transferred to Bonavista Petroleum under Transfer Approval No. 1353-02-00. All compliance requirements under these approvals were in place and in good standing during the period claimed in this GHG offset project.

[1] Listed on the Alberta Offset Registry as "South Rosevear Acid Gas Injection Project, April 2010."

Figure 1-1 : Bonavista South Rosevear Gas Plant

1.1 Project Scope and Project Site Description

Project Title:	Bonavista Acid Gas Injection at South Rosevear
Project Purpose and Objective:	This project's purpose and objective is to determine the direct and indirect emission reductions as a result of the continued operation of AGI at the South Rosevear Gas Plant under the new management of Bonavista Petroleum. This project is a continuation of a previously registered project: Suncor South Rosevear Acid Gas Injection Project, CSA Project Identifier #2959-5549.[2]
Project Start Date:	March 5, 2007
Credit Start Date:	March 5, 2007
Credit Duration Period:	March 5, 2007 to March 4, 2015
Expected Project Lifetime:	This project concludes March 4, 2015. However, on

[2] Suncor South Rosevear Acid Gas Injection Offset Project registered on the Alberta Emission Offset Registry and listed at http://www.carbonoffsetsolutions.ca/aeor/index.php?p=view_project&id=149.

	or before this date the project will be re-examined and may apply for a 5 year crediting extension.
Reporting Period:	January 1, 2010 to December 31, 2011
Estimated Emission Reductions	Previously claimed GHG emission reductions are as follows: 2007: 14,950 tonnes of CO_2e 2008: 7,469 tonnes of CO_2e 2009: 3,145 tonnes of CO_2e Total: 25,564 tonnes of CO_2e For the reporting period of this report, the estimated project GHG emission reductions are as follows: 2010: 18,650 tonnes of CO_2e 2011: 13,775 tonnes of CO_2e Total: 32,425 tonnes of CO_2e For the remaining period of the project, the GHG emission reductions are estimated to be as follows: 2012: 15,000 tonnes of CO_2e 2013: 15,000 tonnes of CO_2e 2014: 15,000 tonnes of CO_2e 2015: 2,500 tonnes of CO_2e Total: 47,500 tonnes of CO_2e
Quantification Protocol:	Quantification Protocol for Acid Gas Injection, May 2008, Version 1, Alberta Environment.
Protocol Justification:	The selected Protocol (Quantification Protocol for Acid Gas Injection, May 2008, Version 1, Alberta Environment) has direct applicability to this project as it sets out both the eligibility and quantification

requirements for the resultant GHG emission reductions. Furthermore, the Protocol sets out the requirements for the project activities to be considered additional, real and, demonstrable.

The project captures and permanently sequesters the acid gas stream that previously was processed by a Sulphur Recovery Unit (SRU). The project also eliminates the previous requirement to incinerate a significant amount of tail gas from the SRU, further reducing GHG emissions from the baseline.

Project Legal Land Description:

This project is located in Alberta at the South Rosevear Gas Plant and is unchanged from the previous project[3].

Acid gas processing occurs at the Gas Plant which is located at LSD 16-11-54-15 W5

The acid gas injection well is located at LSD 8-11-54-15 W5

Ownership:

Bonavista Petroleum is the majority owner and operator of the South Rosevear Gas Plant.[4] Bonavista Petroleum has the legal authority to bind the facility and its operations as it relates to the GHG reductions created in this project. Preferred Carbon Land Management Solutions (PCLMS) has acquired the GHG reductions created in this project.

Reporting and Verification:

The reporting period for this project begins January 1, 2010 and ends December 31, 2011 with an annual delineation of the resultant GHG reductions.

Preferred Carbon Land Management Solutions (PCLMS) has contracted KMPG Performance Registrar Inc to conduct project verification. Selection of KPMG and the subsequent verification process follows the definitions and criteria set out in the SGER (2007) and described in the additional guidance related to offset verification.[5] Accordingly, both the project verifier and the verification plan are

[3] Suncor South Rosevear Acid Gas Injection Offset Project, CSA Project Identifier #2959-5549.
[4] Bonavista Petroleum acquired ownership in the GHG reductions associated with the project starting January 1, 2010.
[5] Section 6.0 – Third Party Verification, Technical Guidance for Offset Project Developers, Version 2.0, January 2011, SGER, Alberta Environment

developed in accordance with the regulation.

Project Registration: This project and resulting emissions reductions will only be listed with Alberta Emissions Offsets Registry (AEOR). No other registrations will be made.

Project Activity: This project is based on the GHG reductions created as a result of a change in the processing of acid gas at the South Rosevear Gas Plant. In particular, the SRU previously in operation at the facility was replaced with an acid gas injection scheme. The AGI permanently sequesters the acid gas containing significant amounts of CO_2 in a well defined geological formation (Beaverhill Lake B Pool). The AGI scheme also replaces the requirement for incineration of the tail gas stream from the SRU resulting in significant reductions in the consumption of fuel gas and associated GHG emissions.

This project meets the additional criteria as an eligible project type as set out under the SGER as follows:

Offset Project Eligibility Criteria	Bonavista AGI at South Rosevear
Occur in Alberta	The project is assured to have occurred in Alberta since all GHG offsets created are linked directly to legal surveyed descriptions (LSDs) unique to the Province.
Result from actions not otherwise required by law and be beyond business as usual and sector common practices	Project activities are the result of voluntary actions taken. The AGI scheme, or project condition, has been implemented at a non-regulated facility and is not required by law.
Result from actions taken on or after January 1, 2002	The AGI scheme, or project condition, was implemented on March 5, 2007.
Be real, demonstrable, quantifiable, and verifiable	The project applies significant due diligence to confirm the occurrence of qualifying activities and the quantity of qualifying activities. The project is verifiable.

Have clearly established ownership	PCLMS has established clear and legal ownership of all GHG emission reductions from this project.
Be counted once for compliance purposes	This project and the resulting Verified Emission Reductions/Removals are unique, apply to specific years, and will only be listed once.
Be implemented according to a Government of Alberta approved quantification protocol	The Government of Alberta has extensively examined this type of project and has determined it to be an eligible project type under the Specified Gas Emitters Regulation 2007 (SGER 2007). This project applies an approved protocol and accompanying guidance.
Be third party verified by a qualified person(s) meeting the requirements for a third party auditor under section 18 of the Regulation	PCLMS has contracted KPMG PRI and confirmed their qualifications meet the requirements of the Regulation.
Be registered on the Alberta Emissions Offset Registry	This project and resulting emissions reductions will only be listed with Alberta Emissions Offsets Registry (AEOR).

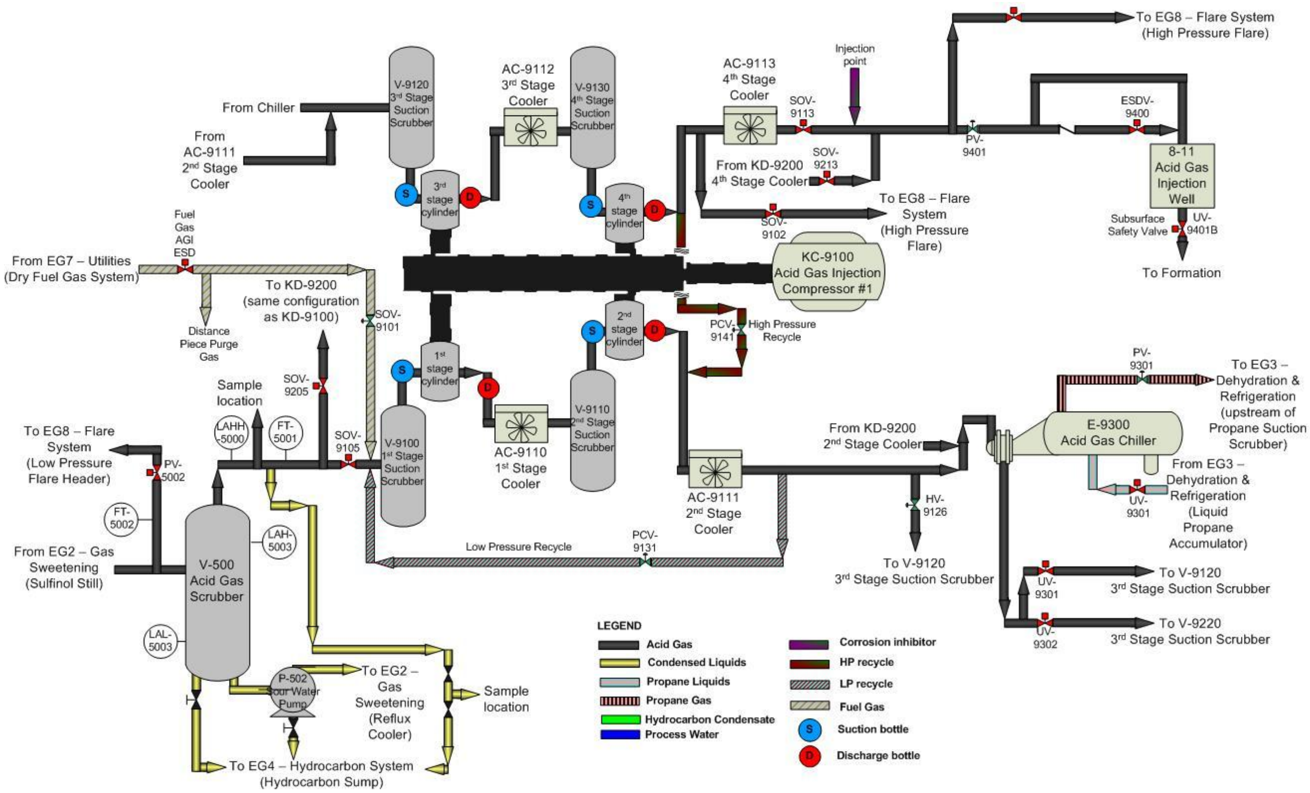
1.2 Conditions Prior to Project Initiation

Processing of sour natural gas requires the safe removal or destruction of H_2S. Prior to the implementation of the AGI scheme at the South Rosevear Gas Plant, sour gas processing was based on a three-stage Claus sulfur recovery unit (SRU) with associated tail gas incineration. The SRU had been in operation from 1979 to the start date of the project. The configuration and normal operating parameters of the SRU included a waste heat boiler and four condensers which supplemented high and low pressure steam for use in the facility operations. The SRU created a tail gas stream which was incinerated on site to safely destroy any remaining H_2S and trace compounds. This required significant amounts of fuel gas to be consumed and was mandated to operate with a stack top temperature of at least 450º C by Alberta Environment Approval No. 1353-02-00. Therefore, all the CO_2 separated from the raw natural gas and fuel gas consumed by tail gas incinerator was emitted to the atmosphere.

1.3 How the Project will Achieve GHG Emission Reductions

The AGI scheme replaces a pre-existing SRU. The AGI scheme is designed to collect, compress and inject the acid gas stream from the sulfinol regenerator into a well defined geological formation. The following process flow diagram describes the AGI at the South Rosevear Gas Plant:

Figure 1-2: AGI Process Flow Diagram



The AGI scheme achieves GHG emission reductions by replacing the pre-existing SRU resulting in a net reduction in GHG emissions for a given volume of acid gas. The project can be described in two (2) distinct phases of implementation: 1) the installation and operation of the AGI equipment and, 2) the decommissioning of the SRU and associated tail gas incinerator. Installation of the AGI equipment included the following major components:

- 2 4-stage electric compressors to compress the acid gas for injection into the reservoir. Each unit has a rated 800 brake horsepower operating with 3-phase electric motors equipped with variable frequency drives at 900 rpm.
- Acid gas chiller was installed to cool the acid gas to 15º C, but under subsequent operating conditions it was determined un-necessary and is not used.
- Acid Gas Pipeline that runs underground approximately 600 meters to the injection well site.

- Acid Gas Injection Well located at 8-11-54-15 W5. Based on a pre-existing well, it was converted to an injection well at 3280 meters in depth.
- Low Pressure Boiler was installed to replace the waste heat boiler in operation under the pre-existing SRU (Claus process). The H_2S concentrations make the Claus process exothermic and that excess heat was captured and used to create steam for the facility.
- Pressure Control Value at the well head. A Fischer DVC 6010 positioner operates the value using fuel gas instead of instrument air.

The pre-existing SRU has been decommissioned and remains on-site. The decommissioning did not result in a significant increase in GHG emissions associated with implementation of the project and occurred in a prior period to this project. Therefore, the GHG emissions associated with decommissioning the SRU are not included.

1.4 Project Technologies, Products, Services and the Expected Level of Activity

AGI Protocol Applicability Criteria[6]	Bonavista AGI at South Rosevear
"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"	Prior to the implementation of the AGI process at the South Rosevear Gas Plant, acid gas was processed with a multi-stage Claus process and associated tail gas incineration resulting in the direct emissions of GHGs to the atmosphere. While the concentration of H_2S is declining, the operation of the multi-stage Claus unit would have continued (potentially with modification - for example the conversion to a super Claus unit, or a change in reactor bed materials) in the absence of the AGI scheme. Regardless of the exact configuration of the multi-stage Claus process, the safe disposal of the tail gas stream would continue to require incineration and release of CO2, separated from the raw natural gas, to the atmosphere. A process flow of the AGI scheme diagram is provided in Figure 1.2.
"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"	Only Bonavista Petroleum is claiming the GHG reductions and is the majority owner and manager of the South Rosevear Gas Plant.

[6] Quantification Protocol for Acid Gas Injection, Version 1, May 2008, Alberta Environment

"The Acid Gas injection scheme has obtained approval from the Energy Resources Conservation Board (ERCB) and meets the requirements outlined under Directive 051: Injection and Disposal Wells – Well Classifications, Completions, Logging and Testing Requirements"	The ERCB granted approval originally to Suncor Energy Inc, Approval No. 10738. This approval was subsequently transferred to Bonavista Petroleum via Transfer Approval No. 1353-02-00. Throughout the project, acid gas has been injected in accordance with the requirements of the permit into the single well located at LSD 8-11-54-15 W5 and uniquely identified as 00/08-11-054-15W5/2. All breakthrough at producing wells have been identified and reported in accordance with regulations and permit requirements.
"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 project schematics"	Metering of injected acid gas volumes occurs at the inlet side of the acid gas compressors. The acid gas compressors discharge compressed acid gas via a pipeline approximately 600 meters to the injection well. Given the extreme toxicity of H_2S, fugitive emissions are strictly monitored and controlled and therefore fugitive emissions are not an issue.
"The sequestration project involves the installation of an acid gas injection project at - an existing sour natural gas processing facility which commenced operations prior to July 1, 2007, which may either have an operational sulphur recovery unit (i.e. Multi-Stage Claus or Liquid Redox) or may directly incinerate the acid gas stream"	The South Rosevear Gas Plant commenced operations prior to July 1, 2007 and baseline emissions are less than 100,000 tonnes $C0_2e$ per year as set out in the SGER.
"The consolidation or comingling of acid gas streams from multiple emitting facilities during the project's crediting period must be fully accounted for to ensure that each individual emitting facility is eligible to apply this protocol based on the above criteria. The metering and measurement systems implemented for the acid gas injection project activity should allow for disaggregation of the total baseline and project emissions back to the original emitting facilities"	The South Rosevear Gas Plant does not receive any acid gas from other gas processing facilities.
"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"	The quantification of reductions is based on actual measurement and monitoring.

"The project must meet the requirements for offset eligibility as specified in the applicable regulation and guidance documents for the Alberta Offset System"	The Project meets all requirements for GHG offset eligibility as set out in both regulation and project guidance. See Section 1.0 Project Scope and Project Site Description, Offset Project Eligibility Criteria.

1.4.1 Flexibility Mechanisms

The quantification of GHG emission reductions from the Project utilizes two (2) flexibility mechanisms under the Protocol, as follows:

Simulation of the multi-stage Claus process and related tail gas incineration.
Flexibility mechanism 1 was selected on the basis it would allow a more accurate and conservative calculation of GHG emission reductions in the project relative to the baseline methodology, while remaining consistent with the basis of the previous GHG offset project at the South Rosevear Gas Plant[7]. The application, rational and justification for this includes:

- Monthly simulation of the operation of the multi-stage Claus process using Sulsim 7.0 simulation software based on site specific data is used. A recognized industry leading firm was contracted to apply the Sulsim simulation to determine the performance and tail gas stream conditions from the SRU. Accuracy of this approach was directly measureable, as the same simulation had been conducted prior to the AGI scheme and compared to actual operating conditions. The resultant tail gas stream was incinerated under the baseline condition.
- An accepted and industry recognized model and engineering calculations are used to determine the required fuel gas requirements for destruction of the tail gas within license conditions (i.e., a stack top temperature of at least 450º) including site specific conditions and compared to values prior to implementation of the AGI scheme to assess accuracy.

The application of this flexibility mechanism was compared to the default methodology in the Protocol and it was determined to result in a very conservative calculation of Project GHG emission reductions.

Site Specific Emission Factors
Flexibility mechanism 3 was selected as it permits the generic emission factors provided in the Protocol to be replaced with site specific emission factors provided the generation of these factors are sufficiently robust to ensure reasonable accuracy. This Project calculated the site specific emission factor for the combustion of fuel gas and replaces the default Environment Canada emission factor as follows:

[7] Suncor created the "South Rosevear Acid Gas Injection Project, April 2010." GHG offsets from this project were claimed and listed on the AOR for the period ending December 31, 2009.

The fuel gas emission factor calculation followed the best practice guidance from the Canadian Association of Petroleum Producers (CAPP) Estimating GHG Emissions (Calculating GHG Emissions April 2003) as follows:

[(a + 2b + 3c + 4d + 5e + f) x 44.01] / 23.64 = kg CO2/m3 fuel burned

Where: a to f = mole fractions of natural gas components
44.01 = molecular weight of CO2
23.64 = volume in m3 occupied by 1 kmole of gas at 15 degrees Celsius and 101.3 kPa

The site specific fuel gas composition was provided by a third party lab analysis. With this analysis and best practice calculation the use of the site specific emission factor is supported.

1.5 Identification of Risks

Many of the potential risks associated with this project are mitigated by the requirements to gain regulatory approval for an acid injection scheme and to maintain the permit to operate an acid gas injection scheme once approved. These risks include the potential for reversals (failure of geological sequestration), fugitive emissions and, un-monitored GHG emissions in the project condition. This Project operates under ERCB Approval No. 10738 and amended by Approval No. 10738A, which sets out stringent requirements for the safe operation of the AGI scheme and monitoring requirements, including reporting of events outside of permitted operating conditions. These requirements require reporting and monitoring information that if applied correctly, mitigates the risk of over stating project GHG reductions.

A potential measurement risk exists related to undetected or undeclared emission sources. This risk is mitigated through a detailed examination of the AGI scheme relative to its operation. This due diligence did result in the detection of one GHG emitting device that had previously been overlooked.

1.6 Roles and Responsibilities

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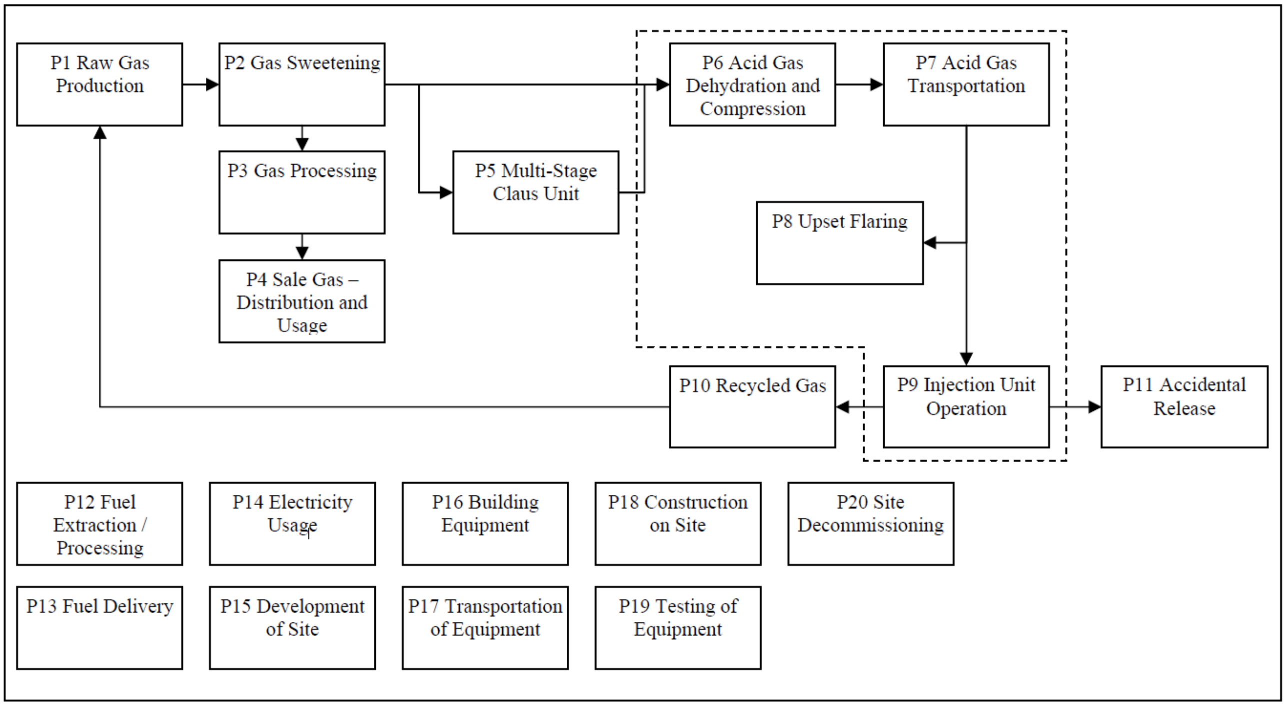
2 Inventory of Sources and Sinks

The Protocol sets out the relevant baseline and project sources and sinks applicable to the AGI scheme.[8] The Project sources and sinks are contained within those defined in the Protocol and described in Figure 2.1. Both the thermal energy credit from the operation of the multi-stage Claus process and the Recycled Gas are included in the quantification of Project GHG emissions. No new additional sources or sinks are identified in the Project beyond those defined the Protocol. However, the Project utilizes 2 flexibility mechanisms in the calculation of the Project condition. The flexibility mechanisms were described in Section 1.3.1 above.

[8] For a description of the requirements of how the relevant sources and sinks are arrived in a protocol, see section 3.5 Sources and Sinks, Technical Guidance for Offset Protocol Developers, Version 1.0, January 2011, Alberta Environment.

Figure 2-1: Project Sinks and Sources



Reference: Quantification Protocol for Acid Gas Injection, May 2008, Version 1, Alberta Environment.

2.1 Quantification of Estimated GHG Emissions/Removals

The quantification of the baseline and project conditions follow the calculation methods set out in the Protocol and, in particular as follows:

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

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

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

Where:

Emissions in the Baseline
Emissions $_{\text{Fuel Extraction and Processing}}$ = emissions under SS B9 Fuel Extracting/Processing
Emissions $_{\text{Multi-Stage Claus Unit}}$ = emissions under SS B5b Multi-Stage Claus Unit
Emissions $_{\text{Incineration}}$ = emissions under SS B6 Incineration

Emissions in the Project
Emissions $_{\text{Fuel Extracting and Processing}}$ = emissions under SS P12 Fuel Extraction/Processing
Emissions $_{\text{Upset Flaring}}$ = emissions under SS P8 Upset Flaring

Emissions $_{\text{Recycled Gas}}$ = emissions under SS P10 Recycled Gas
Emissions $_{\text{Injection Unit Operation}}$ = emissions under SS P9 Injection Unit Operation

2.1.1 Quantification of Sources and Sinks

The requirements for quantifying GHG emission reductions in this Project are described in the Table 2.1.1 Baseline and Project Data Requirements below. All emission factors applied in the Project are from the Protocol except for CO_2 emissions from fuel gas[9].

Table 2-1: Baseline and Project Data Requirements

Required Data	Description	Measurement Method
Volume of Acid Gas Injected	Volume of acid gas injected in the project condition	Continuous metering just prior to the acid gas compressor. Meter ID FT5001
Composition of acid gas injected	% composition of acid gas injected in the project condition	Monthly sampling and gas analysis by a Maxxum Analytics
Volume of acid gas flared	Volume of acid gas flared in the project condition	Continuous metering. Meter ID FT5002
Volume of fuel gas used to flare acid gas	The volume of fuel gas required for the safe destruction of H_2S during upset or shutdown conditions.	Calculated according to the contingency method for SS P8 in Table 2.5 of the Protocol.
Volume of sour gas produced from each producing well in the Beaverhill Lake B Pool	The volume of sour gas produced from wells in the same geological formation as the injection well are subject to breakthrough and recycling of the H_2S and CO_2 from the project condition.	Continuous metering at each of the wellheads as required by ERCB reporting requirements. There are 3 active wells producing sour gas: 7-14-54-15, 9-22-54-15 and, 12-23-54-15.
Composition of sour gas produced from each producing well in the Beaverhill Lake B Pool	% composition of the sour gas produced from wells in the same geological formation as the injection well are subject to breakthrough and recycling of the H_2S and CO_2 from the project	% composition is measured by an on-site chromatograph from January 2011. Prior to this, composition analysis is provided by Maxxum Analytics.

9 Site specific emission factor calculated as per Section 1.3.1 of the Project Plan, applying CAPP followed the best practice guidance from the Canadian Association of Petroleum Producers (CAPP) Estimating GHG Emissions (Calculating GHG Emissions April 2003)

Required Data	Description	Measurement Method
	condition.	
Composition of the fuel gas used on-site	% composition of the fuel gas used on site including HHV.	Monthly sampling and gas analysis by a Maxxum Analytics
Thermal energy credit from the SRU in the baseline	The multi-stage Claus process at H_2S levels in the baseline condition is exothermic. This thermal energy is used in the baseline to provide steam production.	Acid gas flow, temperature, pressure and composition from the Project was used in the Sulsim 7.0 simulation of the Multi-Stage Claus process[10]. The process energy recovered is calculated from the Sulsim output.
Volume of fuel gas used in the project condition to replace the thermal energy from the SRU	As a result of the AGI scheme, a second boiler was installed to provide adequate steam for the facility.	Fuel gas volumes are estimated using standard engineering calculations applying standard heat release calculations.
Volume of fuel gas consumed to incinerate tail gas in the baseline	Tail gas requires incineration for safe disposal and is a regulatory requirement. The SRU tail gas conditions in the baseline were estimated from the Sulsim simulation output.	The fuel gas requirements for tail gas incineration are estimated with an industry standard combustion simulator given the tail gas conditions and site specific conditions.
Volume of fuel gas used in the operation of the AGI injection unit.	A Fisher DVC-6010 positioner controls the pressure control valve at the well head. Fuel gas is vented in its operation.	The fuel gas requirements are estimated based on the maximum flow from the positioner operating at normal conditions as per manufacturers specifications.

Sources and Sinks excluded from the Project was limited to one: it was assumed that no fuel gas was used to operate the multi-stage Claus unit. This resulted in a more conservative estimate of the Project's GHG emission reductions, since it reduced the emissions in the baseline condition. This assumption was also supported by the composition of the acid gas and the design of the pre-existing Claus unit. The composition of the acid gas stream supported combustion, reflected in the thermal energy credit in the baseline, without the requirement for supplemental fuel gas. Therefore, fuel gas usage was limited to only start-up of the SRU, or Claus unit, which was a very infrequent event.

[10] The simulation was conducted by an industry expert firm. Full documentation of the simulation, its inputs, its outputs, and a description of accuracy are contained in the Project file.

2.2 Estimate of Total GHG Emission Reductions/Removals Enhancements Attributable for the Project.

The claimed GHG emission reductions as a result of implementing the Project identifies each applicable GHG gas species. Section 4.0 below identifies the Project specific formula used in the quantification of the relevant GHGs. The GHG reductions expected in the Project are described in Table 2.2.

Table 2-2: Expected Project GHG Emission Reductions

Project Year	CO_2	CH_4	N_2O	Total
			CO_2e in Tonnes	
2010	18,604	35	11	18,650
2011	13,742	23	10	13,775
Total	32,346	58	21	32,425

3 Identification of Baseline

The baseline condition for this Project is the continued operation of a three (3) bed Claus unit and the direct and indirect emissions associated with its operation. The baseline is dynamic as the volume and composition of the acid gas produced is expected to vary significantly over time. Not all GHG emissions are included in the baseline condition due to their de minimis impact and to be conservative.

The South Rosevear Gas Plant was built in 1979 and was originally equipped with the Claus unit that remained in continuous operation until the AGI scheme was implemented on March 5, 2007. The Claus unit converted H_2S into elemental sulfur and incinerated the tail gas stream to destroy any remaining H_2S. The Claus unit has been de-commissioned, but the equipment remains on site.

A significant factor in the decision to adopt the AGI scheme, is the declining levels of H_2S in the sour gas processed at the Plant. The original Claus unit was designed to treat 1409 e^3m^3/day of sour gas containing 8% H_2S and 6% CO_2. By 2007, H_2S levels had declined significantly to the point where the existing Claus unit was operating at 20% of its design capacity. However, had the AGI scheme not been adopted the most likely outcome would have been continued operation of the Claus based process. A review of industry practices support the conclusion that the most likely scenarios would have been a re-design of the Claus unit for lower H_2S levels [11] or the addition of greater amounts of sour gas to processing. Both scenarios are well supported by the past experience at the Plant that has a high level of confidence in the Claus process and its recognition as a mature technology. Therefore the baseline condition is the continued operation of the Claus unit without adjustment to its

[11] Sulphur Recovery at Sulphur Emissions at Alberta Sour Gas Plants, Annual Report for the 2010 Calendar Year, July 2011, ERCB.

configuration to be conservative.[12] There are three (3) relevant GHG emission sources and sinks in the baseline condition to be considered as follows:

1. Thermal Energy Credit

The operation of the Claus unit at H_2S levels present in the acid gas stream is exothermic and this energy in captured in a waste heat recovery process. This thermal energy offsets a significant amount of fuel gas usage required to produce process steam at the Plant. Therefore, the baseline condition includes a credit for the GHG emissions created in the project condition to replace this energy source.

2. Incineration

The operation of the Claus unit resulted in a tail gas stream that contained CO_2 and residual amounts of H_2S that requires safe destruction. The operation of the tail gas incinerator consumes significant amounts of fuel gas to ensure safe destruction. Alberta Environment Approval No. 1353-02-00 mandated a minimum tail gas incinerator stack top temperature of at least 450º C to ensure complete destruction of the remaining H_2S. This, site specific conditions and, design of the incinerator all impact the volume of fuel gas consumed. The GHG emissions from the operation of the tail gas incinerator includes both the CO_2 present in the acid gas stream and the GHG emissions created by combustion of fuel gas.

3. Sulfur Storage and Handling

The operation of the Claus unit converts H_2S to elemental sulfur. This sulfur is handled and stored in liquid form which would have resulted in additional GHG emissions in the baseline. These emissions are considered to be very limited and are not included in the baseline condition to be conservative.

The AGI scheme replaced the pre-existing SRU based on the Claus process. The volume and composition of the acid gas processed is identical under both scenarios, therefore the baseline and project conditions are functionally equivalent.

4 Quantification Plan

The quantification of the baseline and project conditions follow the calculation methods set out in the Protocol and, in particular as follows:

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

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

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

[12] The Sulsim Simulation of the Claus process in place at the South Rosevear Gas Plant assumed that the regulatory mandate to achieve 98.3% sulfur recovery efficiency did not apply. The reduced H_2S conversion efficiency results in a more conservative baseline condition as less fuel gas would be used in the incinerator. All the heating value of the H_2S is used to increase the temperature of the flue gas in the incinerator. Conversely, if the sulphur conversion efficiency were increased in the SRU, a lower amount heat value would have been recovered due to mechanical heat transfer inefficiencies.

Where:

Emissions in the Baseline
Emissions $_{\text{Fuel Extraction and Processing}}$ = emissions under SS B9 Fuel Extracting/Processing
Emissions $_{\text{Multi-Stage Claus Unit}}$ = emissions under SS B5b Multi-Stage Claus Unit
Emissions $_{\text{Incineration}}$ = emissions under SS B6 Incineration

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

A detailed description of the calculations applicable in this Project with reference to the data requirements described in Section 2.1.1 and the Monitoring Plan in Section 5.0 are as follows:

<u>Baseline Condition</u>

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

CO_2 Emissions = Volume of Natural Gas Consumed in Baseline (m^3) × (0.043 kg CO_2/m^3 + 0.090 kg CO_2/m^3)

CH_4 Emissions = Volume of Natural Gas Consumed in Baseline (m^3) × (0.0023 kg CH_4/m^3 + 0.0003 kg CH_4/m^3)

NO_2 Emissions = Volume of Natural Gas Consumed in Baseline (m^3) × (0.000004 kg NO_2/m^3 + 0.000003 kg NO_2/m^3)

Emissions $_{\text{Multi-Stage Claus Unit}}$ = emissions under SS B5b Multi-Stage Claus Unit

Equivalent Volume of Fuel Gas to Generate Recoverable Heat = Recoverable Heat (MJ) ÷ (Lower Heating Value of Site Specific Natural Gas (MJ/m3) × Boiler Efficiency (%))

CO_2 Emissions = Equivalent Volume of Fuel Gas to Generate Recoverable Heat (m^3) × Site Specific Emissions Factor (kg CO_2/m^3)

CH_4 Emissions = Equivalent Volume of Fuel Gas to Generate Recoverable Heat (m^3) × 0.000037 (kg CH_4/m^3)

NO_2 Emissions = Equivalent Volume of Fuel Gas to Generate Recoverable Heat (m^3) × 0.000033 (kg NO_2/m^3)

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

CO_2 Emissions[13] = (Total Volume of Gas Flared (m^3) × Volume % of CO_2 in Gas Flared (%) × 1.87 (kg CO_2/m^3))+ (Volume of Fuel Gas (m^3) × Site Specific Emissions Factor (kg CO_2/m^3))

CH_4 Emissions[14] = (Total Volume of Gas Flared (m^3) × Volume % of CH_4 in Gas Flared (%) × 0.68 kg CH_4/m^3 × 44/16)) + (Volume of Fuel Gas (m^3) × 0.000037 (kg CH_4/m^3))

NO_2 Emissions = Volume of Fuel Gas (m^3) × 0.000033 (kg NO_2/m^3)

Project Condition

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

CO_2 Emissions = Volume of Natural Gas Consumed in Project (m^3) × (0.043 kg CO_2/m^3 + 0.090 kg CO_2/m^3)

CH_4 Emissions = Volume of Natural Gas Consumed in Project (m^3) × (0.0023 kg CH_4/m^3 + 0.0003 kg CH_4/m^3)

NO_2 Emissions = Volume of Natural Gas Consumed in Project (m^3) × (0.000004 kg NO_2/m^3 + 0.000003 kg NO_2/m^3)

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

Volume Supplemental Fuel Gas = Volume of Acid Gas Flared (m^3) × ((20 MJ/m^3 – Lower Heating Value of Acid Gas (MJ/m^3)) ÷ (Lower Heating Value of Fuel Gas (MJ/m^3) – 20 MJ/m^3))

CO_2 Emissions = (Volume of Acid Gas Flared (m^3) × Volume % of CO_2 in Acid Gas Flared (%) × 1.87 (kg CO_2/m^3))+ (Volume of Supplemental Fuel Gas (m^3) × Site Specific Emissions Factor (kg CO_2/m^3))

CH_4 Emissions = (Total Volume of Acid Gas Flared (m^3) × Volume % of CH_4 in Acid Gas Flared (%) × 0.68 kg CH_4/m^3 × 44/16)) + (Volume of Suplemental Fuel Gas (m^3) × 0.000037 (kg CH_4/m^3))

NO_2 Emissions = Volume of Supplemental Fuel Gas (m^3) × 0.000033 (kg NO_2/m^3)

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

[13] Density of CO_2 at 15°C and 1 atm is 1.87 kg CO_2/m^3; volumetric flows are provided on 15°C and 1 atm basis
[14] Density of CH_4 at 15°C and 1 atm is 0.68 kg CH_4/m^3; volumetric flows are provided on 15°C and 1 atm basis

CO_2 Emissions = Volume of Fuel Gas Consumed at Injection Well (m^3) × Site Specific Emissions Factor (kg CO_2/m^3)

CH_4 Emissions = Volume of Fuel Gas Consumed at Injection Well (m^3) × 0.000037 (kg CH_4/m^3)

NO_2 Emissions = Volume of Fuel Gas Consumed at Injection Well (m^3) × 0.000033 (kg NO_2/m^3)

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

CO_2 Emissions = (Volume of Gas from Well 14-14 (m^3) × Volume % of CO_2 in Gas from Well 14-14 (%) × 1.87 (kg CO_2/m^3)) + (Volume of Gas from Well 9-22 (m^3) × Volume % of CO_2 in Gas from Well 9-22 (%) × 1.87 (kg CO_2/m^3)) + (Volume of Gas from Well 12-23 (m^3) × Volume % of CO_2 in Gas from Well 12-23 (%) × 1.87 (kg CO_2/m^3))

5 Monitoring Plan

The relevant sinks and sources in the Project are linked to the measured parameters in the Monitoring Plan as described in Table 5.1 Monitoring Plan.

Table 5-1: Monitoring Plan

Source/sink identifier or name	B9 Fuel Extracting/Processing
Data parameter	Composition of on-site fuel gas
Measurement method	Measurement and calculations
Data unit	Percentage composition
Source/origin	Third party laboratory analysis
Monitoring frequency	Monthly
Description and support for monitoring method	Most accurate method of measurement available
Uncertainty	N/A
Description and support for deviation from protocol	N/A
Source/sink identifier or name	B5b Multi-Stage Claus Unit B6 Incineration
Data parameter	Volume of acid gas injected
Measurement method	Direct metering and calculations
Data unit	e^3m^3
Source/origin	Meter ID: FT-5001
Monitoring frequency	Continuous
Description and support for monitoring method	Most accurate method of measurement available
Uncertainty	+/- 0.25%

Calibration cycle	Minimum once per year
Description and support for deviation from protocol	N/A
Source/sink identifier or name	B5b Multi-Stage Claus Unit
Data parameter	Composition of acid gas injected
Measurement method	Measurement and calculations
Data unit	Percentage composition
Source/origin	Third party laboratory analysis
Monitoring frequency	Monthly
Description and support for monitoring method	Most accurate method of measurement available
Uncertainty	N/A
Description and support for deviation from protocol	N/A
Source/sink identifier or name	P12 Fuel Extraction/Processing
Data parameter	Composition of on-site fuel gas
Measurement method	Measurement and calculations
Data unit	Percentage composition
Source/origin	Third party laboratory analysis
Monitoring frequency	Monthly
Description and support for monitoring method	Most accurate method of measurement available
Uncertainty	N/A
Description and support for deviation from protocol	N/A
Source/sink identifier or name	P8 Upset Flaring
Data parameter	Volume of acid flared
Measurement method	Direct metering
Data unit	e^3m^3
Source/origin	Meter ID: FT-5002
Monitoring frequency	Continuous
Description and support for monitoring method	Most accurate method of measurement
Uncertainty	+/- 0.25%
Calibration cycle	Minimum once per year
Description and support for deviation from protocol	N/A
Source/sink identifier or name	P8 Upset Flaring
Data parameter	Acid gas heating value
Measurement method	Direct Measurement and calculation
Data unit	MJ/m^3
Source/origin	Third party laboratory analysis
Monitoring frequency	Monthly
Description and support for monitoring method	Most accurate method of measurement

Uncertainty	N/A
Description and support for deviation from protocol	N/A
Source/sink identifier or name	P9 Injection Unit Operation
Data parameter	Volume of fuel gas vented
Measurement method	Estimation
Data unit	e^3m^3
Source/origin	Fisher DVC-6010 positioner at injection wellhead
Monitoring frequency	N/A
Description and support for monitoring method	The fuel gas requirements are estimated based on the maximum flow from the positioner operating at normal conditions as per manufacturers specifications.
Uncertainty	N/A
Description and support for deviation from protocol	Most conservative method available
Source/sink identifier or name	P10 Recycled Gas
Data parameter	Volume of sour gas produced from wells 7-14-54-15, 9-22-54-15 and, 12-23-54-15
Measurement method	Direct Metering
Data unit	e^3m^3
Source/origin	Meter ID: Wellhead Meters
Monitoring frequency	Continuous
Description and support for monitoring method	most accurate method of measurement
Uncertainty	+/- 0.25%
Calibration cycle	Minimum once per year
Description and support for deviation from protocol	N/A
Source/sink identifier or name	P10 Recycled Gas
Data parameter	Composition of sour gas produced from wells 7-14-54-15, 9-22-54-15 and, 12-23-54-15
Measurement method	Composition is measured by an on-site chromatograph from January 2011. Prior to this, composition analysis is provided by third party analysis.
Data unit	Percentage composition
Source/origin	Meter ID: 7-14 Chromatograph; Third party laboratory analysis
Monitoring frequency	Minimum monthly
Description and support for monitoring method	most accurate method of measurement
Uncertainty	+/- 0.25% for metered data, N/A for laboratory analysis
Calibration cycle	Minimum once per year
Description and support for deviation from protocol	N/A

6 Data Information Management Systems and Data Controls

PCLMS data information and management systems are based on a structured process that is designed to minimize the risk of inaccuracies and provide robust results. This process includes input data collection, data entry, quality control and quality analysis, quantification of Project GHG emission reductions, record storage and, transparency to verifiers. Integral to this process is PCLMS's Project due diligence to determine both the basis and accuracy of the GHG emission reductions claimed in the Project.

<u>Input data collection</u>
Project data is collected in both electronic and hard copy formats. All data is reviewed prior to entry with reference to outliers, anomalies, and completeness. All data sources are examined to assist in determining accuracy of submitted data.

<u>Data entry</u>
Data entry is restricted to selected users. All data entry is done by experienced personal with a high level of familiarity with the subject matter. All data entry is structured with reference to source documents.

<u>Quality control</u>
All submitted data is reviewed and where applicable, all sources are reviewed as part of the project site visit(s). This includes comparison of scanned hard copies of reports, complied electronic data with reference to sources, and interviews with staff directly responsible for data collection, dissemination, and filing.

All data is reviewed prior to use in the project to ensure completeness and accuracy. All missing values are investigated and all data is examined for outliers and compared to expected values.

Related to due diligence, all data is reviewed to determine accuracy. This includes, but is not limited to, examination of calibration reports, site inspections and, a detailed review of engineering drawings.

<u>Quality analysis</u>
A sample of GHG emission reductions are selected and recalculated. All differences between calculated values and those determined in the Project are investigated.

All calculations, formulas, and summary values are reviewed independently of the operator of the data management system.

<u>Quantification of GHG emission reductions</u>
PCLMS has developed a GHG emissions calculator for acid gas injection projects. The calculator was developed and is maintained by an experienced in house professional engineer. All calculations are transparent and permit traceability to source data.

<u>Transparency to verifiers</u>
The inputs and resultant Project GHG reductions are presented in a transparent manner. PCLMS collects and retains all required records in its data management system to allow verifiers to

independently review data sources, data files, and calculations. All background materials and full documentation of all third party calculations, simulations, or professional services is included.

Record Management and Data Storage

PCLMS retains both hard and electronic copies of all project data for 7 years after the Project completion. All data used in the completion of the project is retained by PCLMS. All data is stored in a secure environment and all electronic data is regularly and securely backed up.

7 PROJECT DEVELOPER SIGNATURE

I am a duly authorized corporate officer of the Proponent mentioned above and have personally examined and am familiar with the information submitted in this Offset Project Plan including the accompanying Greenhouse Gas Assertion on which it is based. Based upon reasonable investigation, including my inquiry of those individuals responsible for obtaining the information, I hereby warrant that the submitted information is true, accurate and complete to the best of my knowledge and belief, and that all matters affecting the validity of the emission reduction claim or the protocol(s) upon which it is based have been fully disclosed. I understand that any false statement made in the submitted information may result in de-registration of credits and may be punishable as a criminal offence in accordance with provincial or federal statutes. The project developer has executed this Offset Project Plan as of the 1st day of February, 2012.

Project Title: Bonavista Acid Gas Injection Project at South Rosevear

Signature:

Date: February 1, 2012
Name: Bruce Love
Title: Director

8 References

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