# SPECIFIED GAS EMITTERS REGULATION

# QUANTIFICATION PROTOCOL FOR ACID GAS INJECTION



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Version 1

Alberta
ENVIRONMENT

ALBERTANS & CLIMATE CHANGE

**Disclaimer:**

The information provided in this document is intended as guidance only and is subject to revisions as learnings and new information comes forward as part of a commitment to continuous improvement. This document is not a substitute for the law. Please consult the *Specified Gas Emitters Regulation* and the legislation for all purposes of interpreting and applying the law. In the event that there is a difference between this document and the *Specified Gas Emitters Regulation* or legislation, the *Specified Gas Emitters Regulation* or the legislation prevails.



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# 1.0 Project and Methodology Scope and Description

This quantification protocol is written for the acid gas processing system operator or an acid gas project developer. Some familiarity with, or general understanding of, the operation of an acid gas processing facility is assumed.

The opportunity for generating carbon offsets with this protocol arises from the direct and indirect reductions of greenhouse gas (GHG) emissions resulting from the geological sequestration of acid gas streams containing greenhouse gases as part of raw natural gas processing.

## 1.1 Protocol Scope and Description

Processing a raw gas stream for the purpose of producing a saleable natural gas product results in an acid gas waste stream by-product. The acid gas stream may contain significant amounts of both hydrogen sulphide ($H_2S$), carbon dioxide ($CO_2$) and other contaminants.

In the baseline condition for projects applying this protocol, the acid gas stream would be processed in a sulphur recovery unit or incinerated to destroy any hydrogen sulphide. The most likely baseline scenarios would therefore be the processing of acid gas in one of the following units;

- In a Liquid Redox Process,
- In a Multi-Stage Claus unit, or
- Directly combusted in an incinerator.

Where, in any case, the $CO_2$ contained in the acid gas stream would be released to the atmosphere from the tail (exit) gas stream of the sulphur recovery and/or incineration process. In the project condition capture and permanent containment of the entire acid gas stream 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 less energy intensive than the baseline processes required for safe disposal of the acid gas stream. **Figure 1.1** offers a process flow diagram for a typical project. In some cases where a Multi-Stage Claus Unit, Liquid Redox or other type of sulphur recovery is already in operation at the project site (in the actual vs. theoretical baseline) the operator may make the decision to maintain the process to produce elemental sulfur and steam from the Claus unit. This flexibility has been incorporated in the protocol.

Where the waste acid gas stream is injected into an active reservoir (where raw natural gas is actively being withdrawn) there is the opportunity for the $CO_2$ to be “recycled” – that is the same $CO_2$ molecule could be withdrawn with the extracted raw gas – separated and re-injected over and over – resulting in an over estimation of the baseline condition and thus the resulting offset. To be conservative in those cases where $CO_2$ is captured and injected into an active gas producing reservoir, all of the $CO_2$ that is contained in raw natural gas extracted from producing wells in the reservoir will be considered recycled and no credit will be claimed.

Finally, the offsets resulting from Acid Gas Injection projects implemented in conformance with this protocol should be considered inherently permanent as a result of the project monitoring and robustness of the injection reservoir mandated by the regulator in the permitting phase.

**Protocol Approach:**

This protocol serves as a generic 'recipe' for project developers to follow in order to meet the measurement, monitoring and GHG quantification requirements for reductions from acid gas sequestration activities under controlled conditions.

The baseline condition represents the GHG emissions from the operation of a Liquid Redox Process, Multi-Stage Claus unit or other type of sulphur recovery technology at an acid gas processing facility or from the direct incineration of an acid gas stream. The appropriate technology for the baseline condition is based on the concentration of $H_2S$ in the acid gas stream. Baseline emissions are therefore calculated from a theoretically appropriately sized Liquid Redox Process or Multi-Stage Claus Unit or directly from the concentration of the acid gas stream. If a Multi-Stage Claus Unit is specified, there is a significant thermal energy credit resulting from the exothermic reaction in the unit that needs to be considered. **FIGURE 1.2** offers a process flow diagram for a typical baseline configuration.

**FIGURE 1.1: Process Flow Diagram for Project Condition**

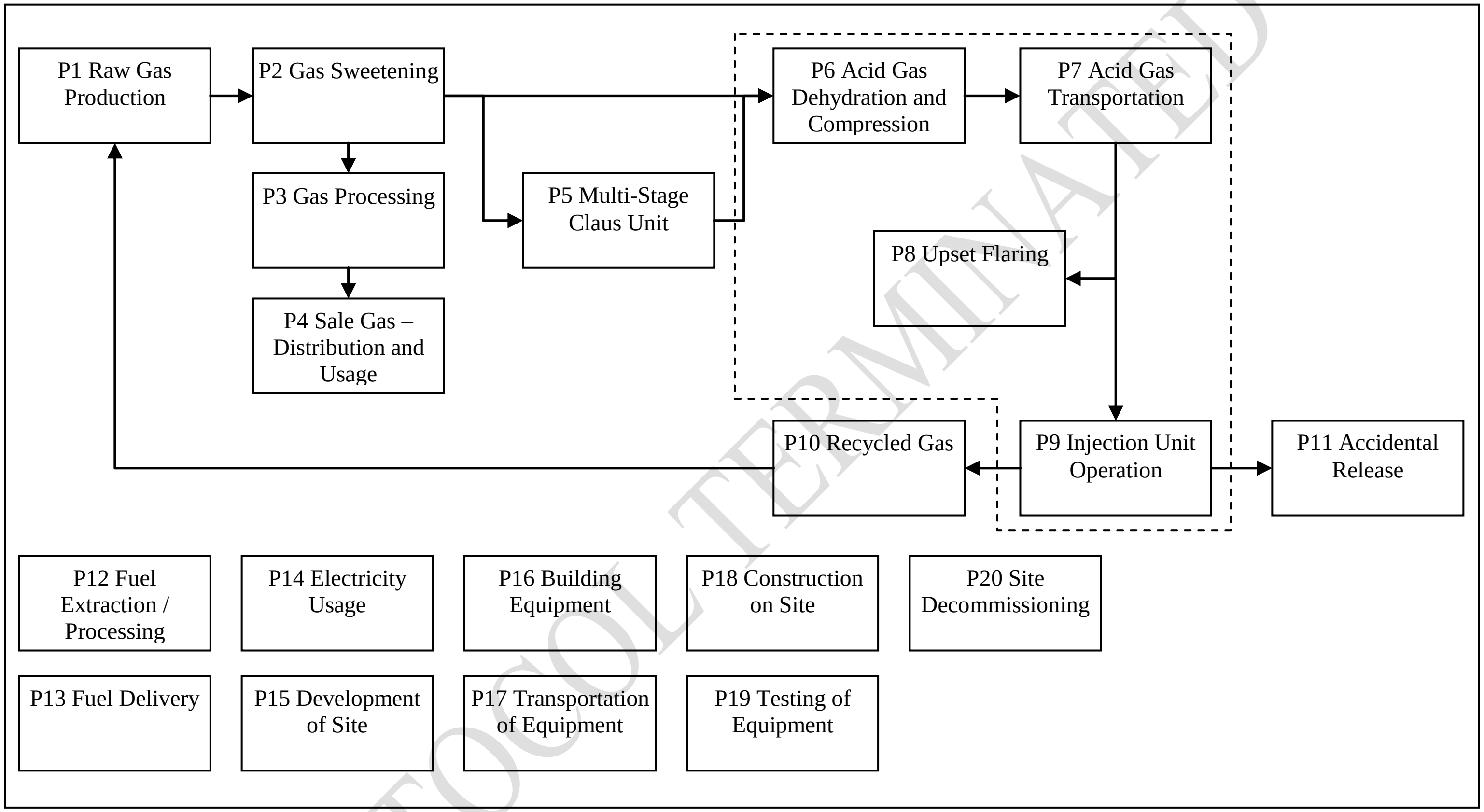
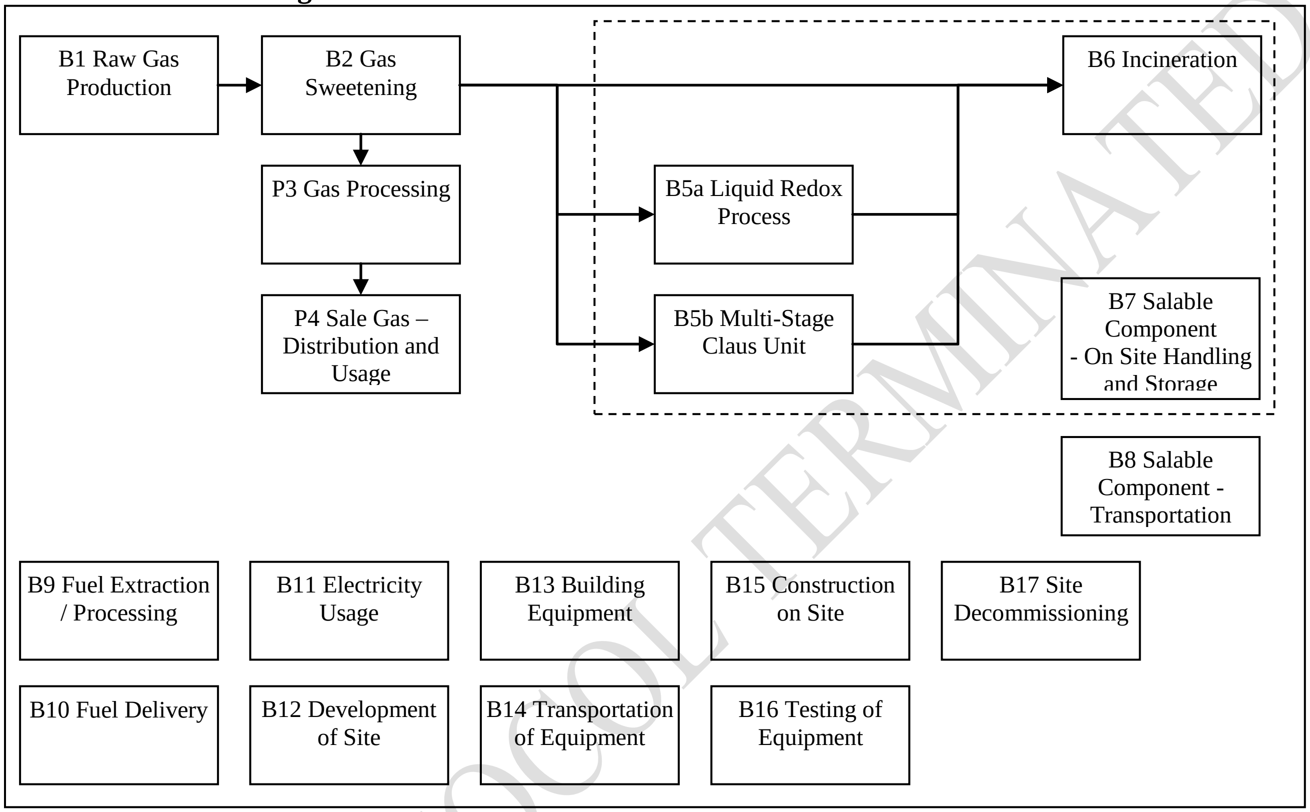


**FIGURE 1.2: Process Flow Diagram for Baseline Condition**



**Protocol Applicability:**

To demonstrate that a project meets the requirements under this protocol, the project developer must provide evidence 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 Energy Resources Conservation Board (ERCB) 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 project schematics;

5. The sequestration project involves the installation of an acid gas injection project at one of the following;

    a. 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;
    b. Any new natural gas processing facility constructed after July 1, 2007 with total facility GHGs output in the first year of operation, inclusive of any $CO_2$ that has been captured and sequestered, less than the identified coverage threshold on direct emissions as defined by the *Specified Gas Emitter Regulation*. Therefore acid gas injection projects applying this protocol at natural gas processing facilities commissioned after July 1, 2007 must also have total baseline emissions, calculated as per Table 2.4 of this protocol, less than the identified coverage threshold for direct emissions as defined by the *Specified Gas Emitter Regulation*[1].

6. 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

[1] Treatment of sequestered $CO_2$ from large-scale (>100,000 tonnes CO2 / year under baseline conditions) acid gas injection projects will be considered as part of a broader review on policies to support the advancement of carbon capture and storage in Alberta

the acid gas injection project activity should allow for disaggregation of the total baseline and project emissions back to the original emitting facilities.

7. 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

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

**Protocol Flexibility:**

Flexibility in applying the quantification protocol is provided to project developers in the following ways:

1. Project developers may use alternative monitoring methodologies and/or equipment rather than the methodologies and/or equipment described in this protocol. The developer must justify that the chosen methodology and/or equipment provides equivalent or more conservative data than the specified equipment;

2. Project developers may use an alternative sulphur recovery technology than the Claus and Liquid Redox technologies described in this protocol to quantify the baseline. The use of an alternate technology would be acceptable if a different type of sulphur recovery technology is assessed as the preferred baseline scenario or is already installed and operational at the project site. The developer must justify that the chosen methodology for calculating emissions from the alternate technology is based on engineering designs or one year or more of operational data and provides an equivalent or more conservative estimate of baseline emissions;

3. Site specific emission factors may be substituted for the generic emission factors indicated in this protocol document. The methodology for generation of these emission factors must be sufficiently robust as to ensure reasonable accuracy;

4. Where a significant volume of the raw gas is produced from the same reservoir as the acid gas injection well, an alternate methodology for calculating the volume of recycled gas may be used. The proponent must justify that the chosen methodology provides verifiable data;

5. Projects may be developed where existing Claus units will remain in place. The baseline condition in this case should be redefined to exclude emissions resulting from the operation of the existing Claus unit;

6. The thermal energy credit produced by a Multi-Stage Claus unit may be calculated by relating the sulphur content of the acid gas input stream to the exothermic energy produced in the Claus process;

7. Where the thermal energy credit produced by a Claus unit is relatively small, the related emissions may be excluded. The proponent must justify the decision to exclude these emissions by demonstrating the relative quantity;

8. For existing acid gas injection facilities that do not collect project data pertaining to the percentage of methane contained in the injected acid gas (data that is used in calculations for SS P8 Upset Flaring and SS B6 Incineration), this component of the calculation can be excluded as it is conservative to exclude these emissions. It is expected that new facilities would have the means to account for methane concentrations in the raw gas streams; and

9. In advance of a defined approach for large nature gas processing facilities constructed after July 1, 2007 with baseline facility GHG emissions that would exceed the coverage threshold for direct emissions as defined by the *Specified Gas Emitter Regulation* flexibility can be provided if the project proponent can demonstrate that the implementation of an acid gas injection project is faced with significant technical, logistical or financial barriers compared to other alternatives and that acid gas injection represents the best available sulphur control technology. The project proponent may submit an application to Alberta Environment for approval to claim offsets under this protocol. The application for approval must include sufficient detail and supporting documentation so as to outline how the acid gas injection project would demonstrate incremental environmental benefits and exceed business as usual site operations.

If applicable, the project developer must indicate and justify why flexibility provisions have been used.

## 1.2 Glossary of New Terms

PLEASE REFER TO - [HTTP://WWW.GLOSSARY.OILFIELD.SLB.COM/MAININDEX.CFM?ID=1](HTTP://WWW.GLOSSARY.OILFIELD.SLB.COM/MAININDEX.CFM?ID=1)

| | |
|---|---|
| Acid Gas: | A gas that can form acidic solutions when mixed with water. The most common acid gases are hydrogen sulfide [$H_2S$] and carbon dioxide [$CO_2$] gases. Both gases cause corrosion; hydrogen sulfide is extremely poisonous. Hydrogen sulfide and carbon dioxide gases are obtained after a sweetening process has been applied to sour natural gas. |

| | |
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| Acid Gas Injection: | Injection of acid gas into deep geological formations including, but not necessarily limited to, depleted oil and gas reservoirs and deep saline aquifers. |
| Aquifer: | A water-bearing portion of a petroleum reservoir with a water drive. |
| Reservoir: | A subsurface body of rock having sufficient porosity and permeability to store and transmit fluids. Sedimentary rocks are the most common reservoir rocks because they have more porosity than most igneous and metamorphic rocks and form under temperature conditions at which hydrocarbons can be preserved. A reservoir is a critical component of a complete petroleum system. |

# 2.0 Quantification Development and Justification

The following sections outline the quantification development and justification.

## 2.1 Identification of Sources and Sinks (SS's) for the Project

Based on the process flow diagrams provided in **FIGURE 1.1**, the project SS's are organized into life cycle categories in **FIGURE 2.1**. Descriptions of each of the SS's and their classification as controlled, related or affected are provided in **TABLE 2.1**.

**FIGURE 2.1: Project Element Life Cycle Chart**

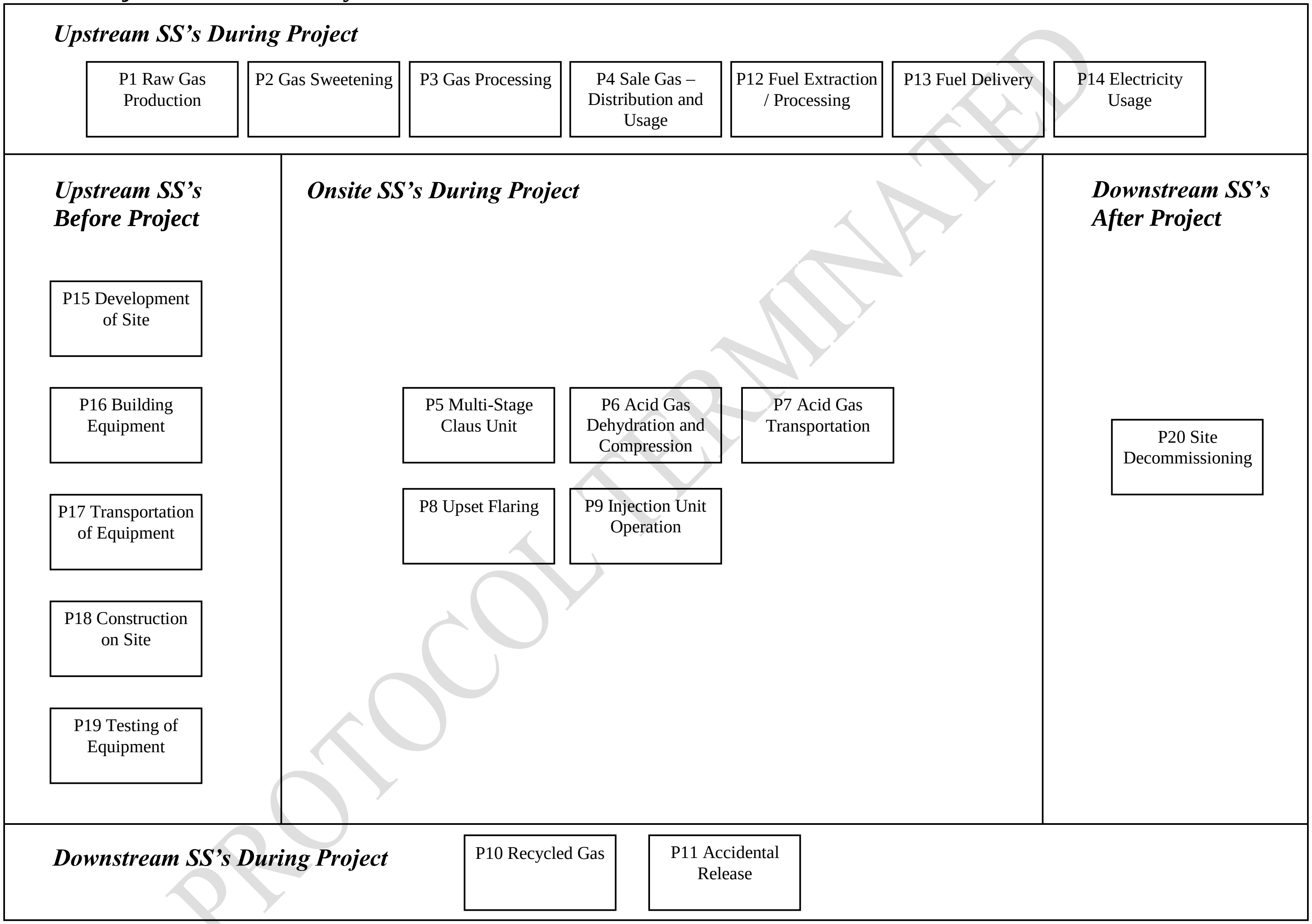

**Table 2.1: Project SS's (Sources and Sinks)**

| 1. SS | 2. Description | 3. Controlled, Related or Affected |
|---|---|---|
| **Upstream SS's during Project Operation** | | |
| P1 Raw Gas Production | Raw gas is collected from a group of adjacent wells where the moisture content is reduced by removing water and natural gas condensate. Condensate is transported to oil refineries and wastewater is disposed. The raw gas is piped to processing plants. The quantity of GHGs in the raw gas would need to be tracked. The types and quantities of fuels used in extraction equipment would need to be tracked. | Related |
| P2 Gas Sweetening | An amine treatment is applied to remove hydrogen sulfide and carbon dioxide. Volumes and types of energy inputs would need to be tracked. | Related |
| P3 Gas Processing | Further processing is required to remove water vapour and natural gas liquids (NGL) from the sales gas which is completed through different processes. The resulting sales gas contains small amounts of carbon dioxide. The types and quantities of energy required would need to be tracked. Carbon dioxide in sales gas would need to be tracked. | Related |
| P4 Sale Gas - Distribution and Usage | Natural Gas and other commercially viable NGL products may be input to a pipeline system or transported by rail or truck to customers at another point. The most likely use would be controlled combustion. The quantities of natural gas and NGL products would need to be tracked. Volumes and types of energy would need to be tracked. | Related |
| P12 Fuel Extraction / Processing | Each of the fuels used throughout the on-site component of the project will need to be sourced and processed. The total volumes of fuel for each of the on-site SS's are considered under this SS. Volumes and types of fuels are the important characteristics to be tracked. | Related |
| P13 Fuel Delivery | Each of the fuels used throughout the on-site component of the project will need to be transported to the site. This may include shipments by tanker or by pipeline contributing further greenhouse gas emissions. It is reasonable to exclude fuel sourced by taking equipment to an existing commercial fuelling station as the fuel used to take the equipment to the site is captured under other SS's. | Related |
| P14 Electricity Usage | Electricity may be produced off-site. Measurement of the quantity of electricity required by the facility would need to be tracked. | Related |
| **On-Site SS's during Project Operation** | | |
| P5 Multi-Stage Claus Unit | A Multi-Stage Claus Unit may be used (in addition to or upstream of the acid gas injection system) to reduce $H_2S$ content of the acid gas by removing elemental sulphur through a multi-stage process. The process is exothermic. Quantities and types for each of the energy inputs may need to be tracked. Net energy production from the process may need to be tracked. | Controlled |

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| P6 Acid Gas Dehydration and Compression | The compressor and dehydration systems may be fuelled by diesel, natural gas or other fossil fuels and these additional GHG emissions are incremental to the project. Quantities and types for each of the energy inputs may need to be tracked. | Controlled |
| P7 Acid Gas Transportation | Compressed acid gas may be shipped in a pipeline to an injection site. Fugitive emissions may occur from equipment used to transport acid gas to the injection site. The quantity of fugitive emissions would need to be tracked. | Controlled |
| P8 Upset Flaring | Flaring of Acid Gas may be required during upset conditions or during maintenance to facility components upstream of the acid gas injection system. GHG emissions would result from the combustion of natural gas in the flaring process as well as from the $CO_2$ contained in the Acid Gas. Quantities of Acid Gas and natural gas as well as any pilot fuels would need to be tracked. | Controlled |
| P9 Injection Unit Operation | Additional compression and monitoring equipment may be required at the injection site. These systems may be fuelled by diesel or natural gas resulting in GHG emissions. Quantities and types for each of the energy inputs may need to be tracked. | Controlled |
| P11 Accidental Release | Geologically sequestered gas may escape from the reservoir. Six potential escape pathways have been identified in the IPCC Special Report on Carbon Dioxide Capture and Storage. | Controlled |
| **Downstream SS's during Project Operation** | | |
| P10 Recycled Gas | Injected acid gas may be re-circulated back to the gas processing facility or to other facilities through natural gas production wells in the same reservoir as the injection well. The re-circulated gas would be extracted along with produced raw natural gas and be fed back into the process. The number of producing wells in the injection reservoir and the quantity and composition of natural gas extracted from these wells must be tracked in order to determine the quantity of $CO_2$ that is recycled. . | Related |
| **Other** | | |
| P15 Development of Site | Development of the site could include clearing, grading, building access roads as well as civil infrastructure such as access to electricity, gas, water supply and water treatment. Building and structures on the site including offices, storage facilities, storm water drainage, and structures to enclose, support and house equipment may need to be developed. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to develop the site. | Related |
| P16 Building Equipment | Equipment may need to be built either on-site or off-site. This includes all of the components of the storage, handling, processing, combustion, air quality control, system control and safety systems. These may be sourced as pre-made standard equipment or custom built to specification. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment for the extraction of the raw materials, processing, fabricating and assembly. | Related |
| P17 Transportation of Equipment | Equipment built off-site and the materials to build equipment on-site, will all need to be delivered to the site. Transportation may be completed by truck, barge and/or train. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels to power | Related |

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| | the equipment delivering the equipment to the site. | |
| P18Construction on Site | The process of construction at the site will require a variety of heavy equipment, smaller power tools, cranes and generators. The operation of this equipment will have associated greenhouse gas emission from the use of fossil fuels and electricity | Related |
| P19 Testing of Equipment | Equipment may need to be tested to ensure that it is operational. This may result in running the equipment using fossil fuels in order to ensure that the equipment runs properly. These activities will result in greenhouse gas emissions associated with the combustion of fossil fuels and the use of electricity. | Related |
| P20 Site Decommissioning | Once the facility is no longer operational, the site may need to be decommissioned. This may involve the disassembly of the equipment, demolition of on-site structures, disposal of some materials, environmental restoration, re-grading, planting or seeding, and transportation of materials off-site. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to decommission the site. | Related |

## 2.2 Identification of Baseline

The baseline condition for projects applying this protocol is defined as the volume of carbon dioxide that would be released to the atmosphere from the tail gas emitted from a Liquid Redox Process, Multi-Stage Claus unit or other equivalent type of sulphur recovery unit at an acid gas processing facility or from the direct incineration of an acid gas stream. Additionally, the emissions associated with fueling the Liquid Redox Process, Multi-Stage Claus or other type of sulphur recovery unit and the incineration process would be included in the baseline emissions. The technology choice and unit design are dependent upon the concentration of hydrogen sulphide and carbon dioxide in the acid gas input stream. The baseline is thus project-specific and may be based on a pre-existing sulphur treatment unit at the project site or on a theoretical engineering design of an appropriate sulphur treatment unit or incinerator.

The approach to quantifying the baseline will be calculation based, as there are suitable measurement based data available for the applicable baseline condition that can provide reasonable certainty. The baseline scenario for this protocol is dynamic as the volume of carbon dioxide would be expected to change materially relative to the makeup of the acid gas stream. The baseline condition may vary from project to project.

The baseline condition is defined, including the relevant SS's and process, as shown in **FIGURE 1.2**. More detail on each of these SS's is provided in Section 2.3 below.

## 2.3 Identification of SS's for the Baseline

Based on the process flow diagrams provided in **FIGURE 1.2**, the project SS's were organized into life cycle categories in **FIGURE 2.2**. Descriptions of each of the SS's and their classification as either 'controlled', 'related' or 'affected' is provided in **TABLE 2.2**
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**FIGURE 2.2: Baseline Element Life Cycle Chart**

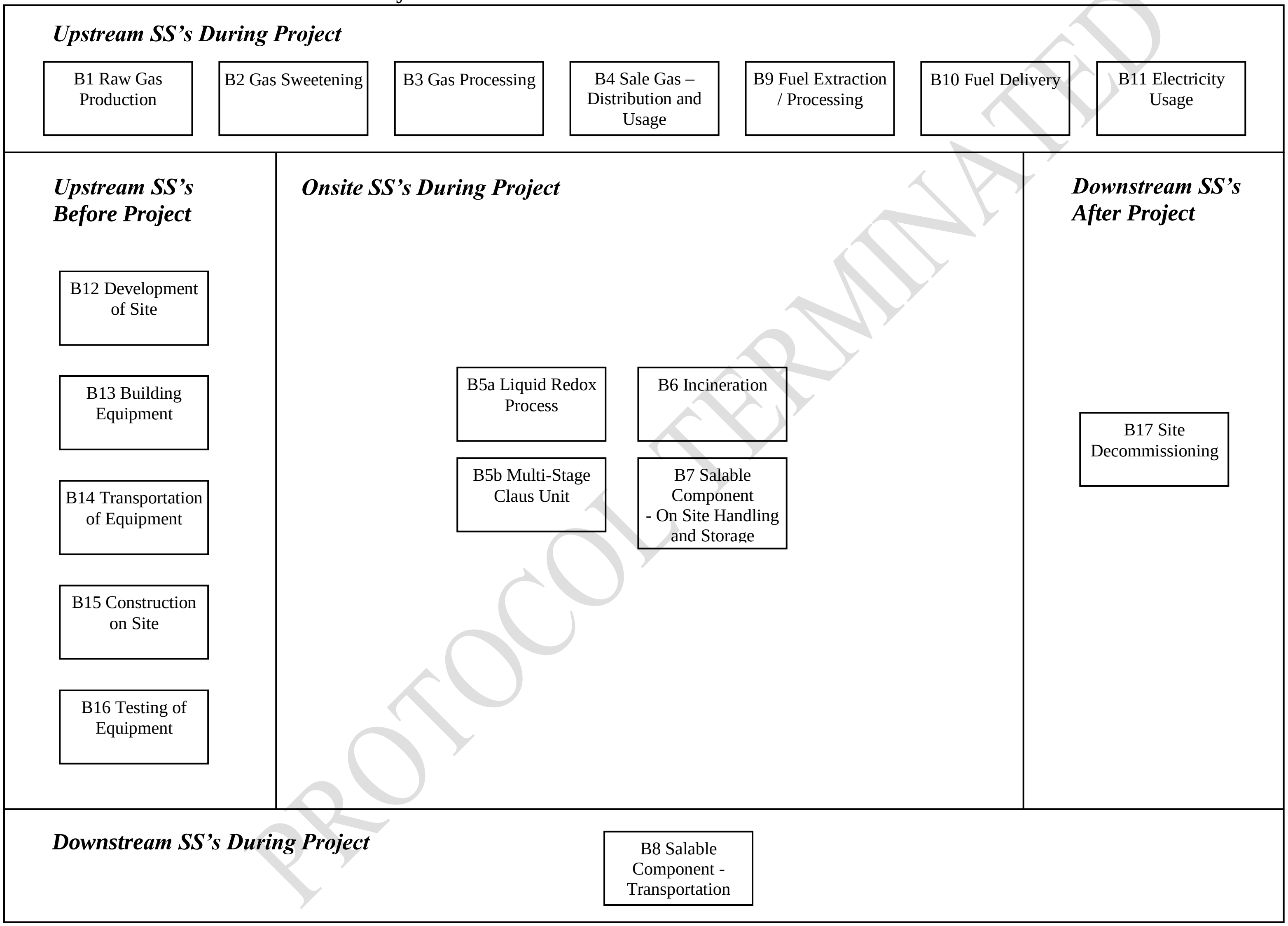

**Table 2.2: Baseline SS's**

| 1. SS | 2. Description | 3. Controlled, Related or Affected |
|---|---|---|
| **Upstream SS's during Baseline Operation** | | |
| B1 Raw Gas Production | Raw gas is collected from a group of adjacent wells where the moisture content is reduced by removing water and natural gas condensate. Condensate is transported to oil refineries and wastewater is disposed of. The raw gas is piped to processing plants. The quantity of GHGs in the raw gas would need to be tracked. The types and quantities of fuels used in extraction equipment would need to be tracked. | Related |
| B2 Gas Sweetening | An amine treatment is applied to remove hydrogen sulfide and carbon dioxide. Volumes and types of energy inputs would need to be tracked. | Related |
| B3 Gas Processing | Further processing is required to remove water vapour, mercury, nitrogen, and natural gas liquids from the sales gas which is completed through different processes. The resulting sales gas contains small amounts of carbon dioxide. The types and quantities of energy required would need to be tracked. Carbon dioxide in sales gas would need to be tracked. | Related |
| B4 Sale Gas – Distribution and Usage | Natural Gas and other commercially viable NGL products may be input to a pipeline system or transported by rail or truck to customers at another point. The most likely use would be controlled combustion. The quantities of natural gas and NGL products would need to be tracked. Volumes and types of energy would need to be tracked. | Related |
| B9 Fuel Extraction / Processing | Each of the fuels used throughout the on-site component of the project will need to be sourced and processed. The total volumes of fuel for each of the on-site SS's are considered under this SS. Volumes and types of fuels are the important characteristics to be tracked. | Related |
| B10 Fuel Delivery | Each of the fuels used throughout the on-site component of the project will need to be transported to the site. This may include shipments by tanker or by pipeline attributing additional greenhouse gas emissions.. It is reasonable to exclude fuel sourced by taking equipment to an existing commercial fuelling station as the fuel used to take the equipment to the site is captured under other SS's and there is no other delivery. | Related |
| B11 Electricity Usage | Electricity may be produced off-site. Measurement of the quantity of electricity required by the facility would need to be tracked. | Related |
| **Upstream SS's during Baseline Operation** | | |

| | | |
|---|---|---|
| B5a Liquid Redox Process | Elemental sulphur is recovered from hydrogen sulfide through a process that employs aqueous-based solutions containing metal ions. The process requires electricity as well as heat that may be provided by the combustion of fuels including natural gas or other fuels. Greenhouse gas emissions from the combustion of fossil fuels or consumption of electricity would need to be tracked. | Controlled |
| B5b Multi-Stage Claus Unit | Elemental sulphur is recovered from hydrogen sulfide through multiple thermal and catalytic reactions. The reactions require heat that may be provided by the combustion of fuels including natural gas or other fuels. Pumps and other equipment require electricity. Greenhouse gas emissions from the combustion of fossil fuel or consumption of electricity would need to be tracked. | Controlled |
| B6 Incineration | Residual hydrogen sulphide contained in Acid Gas not recovered during the upstream sulphur recovery process (if one exists) needs to be incinerated for health and safety reasons. Alternatively at some gas processing plants with low volumes of hydrogen sulphide production an acid gas incinerator may be the only method used to control hydrogen sulphide emissions. GHG emissions would result from the combustion of natural gas in the flaring process as well as from the carbon dioxide content of the Acid Gas. Quantities of Acid Gas and natural gas as well as any pilot fuels would need to be tracked. | Controlled |
| B7 Saleable Component – On Site Handling and Storage | Liquid or solid sulphur produced through the Claus process will need to be handled on site and potentially stored before being transported to market. Equipment to handle sulphur would be fuelled by electricity, diesel, gasoline, propane or natural gas, resulting in GHG emissions. Quantities and types for each of the energy inputs may need to be tracked. | Controlled |
| **Downstream SS's during Baseline Operation** | | |
| B8 Saleable Component - Transportation | Salable elemental sulphur may require further processing and transportation to end users by rail or truck resulting in greenhouse gas emissions. The quantity of emissions would need to be tracked. | Controlled |
| **Other** | | |
| B12 Development of Site | Development of the site could include clearing, grading, building access roads as well as civil infrastructure such as access to electricity, gas, water supply and water treatment. Building and structures on the site including offices, storage facilities, storm water drainage, and structures to enclose, support and house equipment may need to be developed. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to develop the site. | Related |
| B13 Building Equipment | Equipment may need to be built either on-site or off-site. This includes all of the components of the storage, handling, processing, combustion, air quality control, system | Related |

| | | |
|---|---|---|
| | control and safety systems. These may be sourced as pre-made standard equipment or custom built to specification. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment for the extraction of the raw materials, processing, fabricating and assembly. | |
| B14 Transportation of Equipment | Equipment built off-site and the materials to build equipment on-site, will all need to be delivered to the site. Transportation may be completed by truck, barge and/or train. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels to power the equipment delivering the equipment to the site. | Related |
| B15 Construction on Site | The process of construction at the site will require a variety of heavy equipment, smaller power tools, cranes and generators. The operation of this equipment will have associated greenhouse gas emission from the use of fossil fuels and electricity | Related |
| B16 Testing of Equipment | Equipment may need to be tested to ensure that it is operational. This may result in running the equipment using fossil fuels in order to ensure that the equipment runs properly. These activities will result in greenhouse gas emissions associated with the combustion of fossil fuels and the use of electricity. | Related |
| B17 Site Decommissioning | Once the facility is no longer operational, the site may need to be decommissioned. This may involve the disassembly of the equipment, demolition of on-site structures, disposal of some materials, environmental restoration, re-grading, planting or seeding, and transportation of materials off-site. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to decommission the site. | Related |

## 2.4 Selection of Relevant Project and Baseline SS's

Each of the SS's from the project and baseline condition were compared and evaluated as to their relevancy using the guidance provided in Annex VI of the "Guide to Quantification Methodologies and Protocols: Draft", dated March 2006 (Environment Canada). The justification for the inclusion, exclusion, or conditions upon which SS's may be excluded is provided in **TABLE 2.3** below.

**TABLE 2.3: Comparison of SS's**

| 1. Identified SS | 2. Baseline (C, R, A) | 3. Project (C, R, A) | 4. Include or Exclude from Quantification | 5. Justification for Exclusion |
|---|---|---|---|---|
| **Upstream SS's** | | | | |
| P1 Raw Gas Production | N/A | Related | Exclude | Excluded as raw gas production is not impacted by the implementation of project and as such baseline and project conditions will be functionally equivalent. |
| B1 Raw Gas Production | Related | N/A | | |
| P2 Gas Sweetening | N/A | Related | Exclude | Excluded as gas sweetening process is not impacted by the implementation of project and as such baseline and project conditions will be functionally equivalent. |
| B2 Gas Sweetening | Related | N/A | | |
| P3 Gas Processing | N/A | Related | Exclude | Excluded as gas processing is not impacted by the implementation of project and as such baseline and project conditions will be functionally equivalent. |
| B3 Gas Processing | Related | N/A | | |
| P4 Sale Gas – Distribution and Usage | N/A | Related | Exclude | Excluded as emissions from the distribution and usage of upstream products are not impacted by the implementation of project and as such baseline and project conditions will be functionally equivalent. |
| B4 Sale Gas – Distribution and Usage | Related | N/A | | |
| P12 Fuel Extraction / Processing | N/A | Related | **Include** | N/A |
| B9 Fuel Extraction / Processing | Related | N/A | | |
| P13 Fuel Delivery | N/A | Related | Exclude | Excluded as emissions from fuel delivery are not impacted by the implementation of project and as such baseline and project conditions will be functionally equivalent. |
| B10 Fuel Delivery | Related | N/A | | |
| P14 Electricity Usage | N/A | Related | Exclude | Excluded as these SS's are not relevant to the project as the emissions from these practices are covered under proposed GHG regulations. |
| B11 Electricity Usage | Related | N/A | | |
| **Onsite SS's** | | | | |
| P5 Multi-Stage Claus Unit | N/A | Controlled | Exclude | Excluded as emissions from the Multi-Stage Claus Unit (if such a unit continues to operate) are not impacted by the implementation of the project and as such baseline and project conditions will be functionally equivalent. |
| P6 Acid Gas Dehydration and | N/A | Controlled | **Include** | N/A |

| | | | | |
|---|---|---|---|---|
| Compression | | | | |
| B5a Liquid Redox Process | Controlled | N/A | **Include** | N/A |
| B5b Gas Processing – Multi-Stage Claus Unit | Controlled | N/A | **Include** | N/A |
| P7 Acid Gas Transportation | N/A | Controlled | Exclude | Excluded as monitoring of transportation pipeline is highly regulated under $H_2S$ regulation and probability of leakage is extremely low. |
| B6 Incineration | Controlled | N/A | **Include** | N/A |
| P8 Upset Flaring | N/A | Controlled | **Include** | N/A |
| B7 Saleable Component – On Site Handling and Storage | Controlled | N/A | Exclude | Excluded as the emissions from on-site handling and storage of saleable component are not material and occur only under the baseline. |
| P9 Injection Unit Operation | Controlled | N/A | **Include** | N/A |
| P10 Recycled Gas | N/A | Related | **Include** | N/A |
| P11 Accidental Release | N/A | Controlled | Exclude | Excluded as monitoring of reservoir is highly regulated under $H_2S$ regulation and probability of occurrence is extremely low. |
| **Downstream SS's** | | | | |
| B8 Saleable Component – Transportation | Related | N/A | Exclude | Excluded as the emissions from transportation of saleable component are not material and occur only under the baseline. |
| **Other SS's** | | | | |
| P15 Development of Site | N/A | Related | Exclude | Emissions from site development are not material given the long project life and the minimal site development typically required. |
| B12 Development of Site | Related | N/A | | |
| P16 Building Equipment | N/A | Related | Exclude | Emissions from building equipment are not material given the long project life and the minimal equipment typically required. |
| B13 Building Equipment | Related | N/A | | |
| P17 Transportation of Equipment | N/A | Related | Exclude | Emissions from transportation of equipment are not material given the long project life and the minimal transportation of equipment typically required. |
| B14 Transportation of Equipment | Related | N/A | | |
| P18 Construction on Site | N/A | Related | Exclude | Emissions from construction on site are not material given the long project life and the minimal construction on site typically required. |
| B15 Construction on Site | Related | N/A | | |
| P19 Testing of Equipment | N/A | Related | Exclude | Emissions from testing of equipment are not material |

| | | | | |
|---|---|---|---|---|
| B16 Testing of Equipment | Related | N/A | | given the long project life and the minimal testing of equipment typically required. |
| P20 Site Decommissioning | N/A | Related | Exclude | Emissions from site decommissioning are not material given the long project life and the minimal site decommissioning typically required. |
| B17 Site Decommissioning | Related | N/A | | |

## 2.5 QUANTIFICATION OF Reductions, REMOVALS AND REVERSALS OF RELEVANT SS'S

### 2.5.1 Quantification Approaches

Quantification of the reductions, removals and reversals of relevant SS's for each of the greenhouse gases will be completed using the methodologies outlined in **TABLE 2.4**, below. A listing of relevant emission factors is provided in **APPENDIX A.** These calculation methodologies serve to complete the following three equations for calculating emission reductions from the comparison of baseline and project conditions.

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

$$\text{Emissions}_{\text{Baseline}} = \text{Emissions}_{\text{Fuel Extraction / Processing}} + \text{Emissions}_{\text{Liquid Redox Process}} + \text{Emissions}_{\text{Multi-Stage Claus Unit}} + \text{Emissions}_{\text{Incineration}}$$

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

Where:

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

- $\text{Emissions}_{\text{Fuel Extraction / Processing}}$ = emissions under SS B9 Fuel Extraction / Processing
- $\text{Emissions}_{\text{Liquid Redox Process}}$ = emissions under SS B5a Liquid Redox Process
- $\text{Emissions}_{\text{Multi-Stage Claus Unit}}$ = emissions under SS B5b Multi-Stage Claus Unit
- $\text{Emissions}_{\text{Incineration}}$ = emissions under SS B6 Incineration

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

- $\text{Emissions}_{\text{Fuel Extraction / Processing}}$ = emissions under SS P12 Fuel Extraction / Processing
- $\text{Emissions}_{\text{Gas Dehydration and Compression}}$ = emissions under SS P6 Acid Gas Dehydration and Compression
- $\text{Emissions}_{\text{Upset Flaring}}$ = emissions under SS P8 Upset Flaring
- $\text{Emissions}_{\text{Injection Unit Operation}}$ = emissions under SS P9 Injection Unit Operation
- $\text{Emissions}_{\text{Recycled Gas}}$ = emissions under SS P10 Recycled Gas

**TABLE 2.4: 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 $_{Fuel\ Extraction\ /\ Processing}$ = 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. |
| | $CO_2$ Emissions Factor for Fuel Including Production and Processing / EF Fuel $_{i\ CO2}$ | kg $CO_2$ per L / $m^3$ / other | Estimate | From Environment Canada reference documents. (Appendix A) | Annual | Reference values adjusted annually as part of Environment Canada's emissions inventory. |
| | $CH_4$ Emissions Factor for Fuel Including Production and Processing / EF Fuel $_{i\ CH4}$ | kg $CH_4$ per L / $m^3$ / other | Estimate | From Environment Canada reference documents. (Appendix A) | Annual | Reference values adjusted annually as part of Environment Canada's emissions inventory. |
| | $N_2O$ Emissions Factor for Fuel Including Production and Processing / EF Fuel $_{i\ N2O}$ | kg $N_2O$ per L / $m^3$ / other | Estimate | From Environment Canada reference documents. (Appendix A) | Annual | Reference values adjusted annually as part of Environment Canada's emissions inventory. |
| P6 Acid Gas Dehydration and Compression | 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 $_{i\ N2O}$) | | | | | |
| | 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. |

| **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 | 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 | From Environment Canada reference documents. (Appendix A) | Annual | Reference values adjusted annually as part of Environment Canada's emissions inventory. |
| | $CH_4$ 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. (Appendix A) | 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. (Appendix A) | Annual | Reference values adjusted annually as part of Environment Canada's emissions inventory. |
| P8 Upset Flaring | Emissions $_{Upset\ Flaring}$ = (Vol. AG Flared * % $CO_2$ * $\rho_{CO2}$); (Vol. AG Flared * % $CH_4$ * $\rho_{CH4}$ *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 $_{Upset\ Flaring}$ | 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. |
| | 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. |
| | $CO_2$ Composition in AG / % $CO_2$ | % | 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 $CO_2$ / $\rho_{CO2}$ | kg / $m^3$ | Constant | 1.98 kg/$m^3$ at STP | 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 |
|---|---|---|---|---|---|---|
| | $CH_4$ 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 $CH_4$ / $\rho_{CH4}$ | kg / $m^3$ | Constant | 0.717 kg/$m^3$ at STP | N/A | Accepted value |
| | 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 | From Environment Canada reference documents. (Appendix A) | Annual | Reference values adjusted annually as part of Environment Canada's emissions inventory. |
| | $CH_4$ 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 (Appendix A). | 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. (Appendix A) | Annual | Reference values adjusted annually as part of Environment Canada's emissions inventory. |
| P9 Injection Unit Operation | Emissions $_{Injection\ Unit\ Operatoin}$ = 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 $_{Injection\ Unit\ Opertiona}$ | 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. |
| | Volume of Each Type of Fuel Used / 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. |

| 1.0 Project/Baseline SS | 2. Parameter / Variable | 3. Unit | 4. Measured / Estimated | 5. Method | 6. Frequency | 7. Justify measurement or estimation and frequency |
|---|---|---|---|---|---|---|
| | $CO_2$ Emissions Factor for Each Type of Fuel / EF Fuel $_{i\ CO2}$ | kg $CO_2$ per L / $m^3$ / other | Estimate | From Environment Canada reference documents. (Appendix A) | Annual | Reference values adjusted annually as part of Environment Canada's emissions inventory. |
| | $CH_4$ 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. (Appendix A) | 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 (Appendix A). | Annual | Reference values adjusted annually as part of Environment Canada's emissions inventory. |
| P10 Recycled Gas | Emissions $_{Recycled\ Gas}$ = Σ (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 | Direct metering of volume of gas produced at wells within the same reservoir over the reporting period converted to STP conditions. | Continuous metering | Direct metering is standard practice. Frequency of metering is highest level possible. |
| | $CO_2$ Composition in Adjacent Gas / % $CO_2$ | % | Measured | Direct Measurement | Monthly sampling | Gas composition should remain relatively stable during steady-state operation. Frequency of reconciliation provides for reasonable diligence. |
| | Density of $CO_2$ / $\rho_{CO2}$ | $kg/m^3$ | Constant | 1.98 $kg/m^3$ at STP | N/A | Accepted value |
| **Baseline SS's** | | | | | | |
| B9 Fuel Extraction / Processing | Emissions $_{Fuel\ Extraction\ /\ Processing}$ = 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. |

| 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 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 Including Production and Processing / EF Fuel $_{i\ CO2}$ | kg $CO_2$ per L / $m^3$ / other | Estimate | From Environment Canada reference documents. (Appendix A) | Annual | Reference values adjusted annually as part of Environment Canada's emissions inventory. |
| | $CH_4$ Emissions Factor for Fuel Including Production and Processing / EF Fuel $_{i\ CH4}$ | kg $CH_4$ per L / $m^3$ / other | Estimate | From Environment Canada reference documents. (Appendix A) | Annual | Reference values adjusted annually as part of Environment Canada's emissions inventory. |
| | $N_2O$ Emissions Factor for Fuel Including Production and Processing / EF Fuel $_{i\ N2O}$ | kg $N_2O$ per L / $m^3$ / other | Estimate | From Environment Canada reference documents (Appendix A). | Annual | Reference values adjusted annually as part of Environment Canada's emissions inventory. |
| B5a Liquid Redox Process | Emissions $_{Liquid\ Redox\ Process}$ = 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 $_{Liquid\ Redox\ Process}$ | 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 | Estimate | Project Specific Design | Project Development | Engineering report will provide the volume of furl required for an appropriately sized Liquid Redox Process. Represents most reasonable means of estimation. |
| | $CO_2$ Emissions Factor for Each | kg $CO_2$ per L / $m^3$ / other | Estimate | From Environment Canada reference | Annual | Reference values adjusted annually as part of Environment Canada's emissions |

| **1.0 Project/Baseline SS** | **2. Parameter / Variable** | **3. Unit** | **4. Measured / Estimated** | **5. Method** | **6. Frequency** | **7. Justify measurement or estimation and frequency** |
|---|---|---|---|---|---|---|
| | Type of Fuel / EF Fuel $_{i\ CO2}$ | | | documents. (Appendix A) | | inventory. |
| | $CH_4$ 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. (Appendix A) | 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. (Appendix A) | Annual | Reference values adjusted annually as part of Environment Canada's emissions inventory. |
| B5b Multi-Stage Claus Unit | $\text{Emissions}_{\text{Multi-Stage Claus Unit}} = \Sigma\ (\text{Vol. Fuel}_{i} - ((E_{\text{Claus}} * \eta_{\text{Heat}}) / (\eta_{\text{Energy}} * \omega_{\text{Fuel } i}))) * \text{EF Fuel}_{i\ CO2})$ ; $\Sigma(\text{Vol. Fuel}_{i} - ((E_{\text{Claus}} * \eta_{\text{Heat}}) / (\eta_{\text{Energy}} * \omega_{\text{Fuel } i}))) * \text{EF Fuel}_{i\ CH4})$ ; $\Sigma\ (\text{Vol. Fuel}_{i} - ((E_{\text{Claus}} * \eta_{\text{Heat}}) / (\eta_{\text{Energy}} * \omega_{\text{Fuel } i}))) * \text{EF Fuel}_{i\ N2O})$ | | | | | |
| | Emissions $_{\text{Multi-Stage Claus Unit}}$ | 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$_i$ | L / $m^3$ / other | Estimate | Project Engineering Design | Project Definition | Engineering report will specify the volume of fuel gas required for an appropriately sized Multi-Stage Claus Unit. Represents most reasonable means of estimation. |
| | Process Energy Recovered / $E_{\text{Claus}}$ | GJ | Estimate | Project Engineering Design | Project Definition | Engineering report will specify the exothermic energy recovered by an appropriately sized Multi-Stage Claus Unit. Represents most reasonable means of estimation. |
| | Heat Transfer Efficiency / $\eta_{\text{Heat}}$ | - | 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. |
| | Fuel Energy Efficiency / | - | Estimate | Project Engineering | Project Definition | Engineering report will specify the fuel energy efficiency of the secondary |

| 1.0 Project/Baseline SS | 2. Parameter / Variable | 3. Unit | 4. Measured / Estimated | 5. Method | 6. Frequency | 7. Justify measurement or estimation and frequency |
|---|---|---|---|---|---|---|
| | $\eta_{Energy}$ | | | Design | | 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 | From Environment Canada reference documents. (Appendix A) | Annual | Reference values adjusted annually as part of Environment Canada's emissions inventory. |
| | $CH_4$ 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. (Appendix A) | 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. (Appendix A) | Annual | Reference values adjusted annually as part of Environment Canada's emissions inventory. |
| B6 Incineration | Emissions $_{Incineration}$ = (Vol. Gas Flared * % $CO_2$ * $\rho_{CO2}$ ) ; (Vol. Gas Flared * % $CH_4$ * $\rho_{CH4}$ *44/16) ; (((Vol. Gas Flared) * ($HV_{combined}$ – $HV_{AG}$)/($HV_{fuel}$ – $HV_{combined}$)) * EF Fuel $_{i\ CO2}$ ) ; (((Vol. Gas Flared) * ($HV_{combined}$ – $HV_{AG}$)/($HV_{fuel}$ – $HV_{combined}$))* EF Fuel $_{i\ CH4}$ ) ; (((Vol. Gas Flared) * ($HV_{combined}$ – $HV_{AG}$)/($HV_{fuel}$ – $HV_{combined}$)) * EF Fuel $_{i\ N2O}$ ) ; | | | | | |
| | 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 gas entering process. | 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 | Continuous metering or monthly sampling on a volumetric basis | Gas composition should remain relatively stable during steady-state operation. Frequency of reconciliation provides for reasonable diligence. |

| 1.0 Project/Baseline SS | 2. Parameter / Variable | 3. Unit | 4. Measured / Estimated | 5. Method | 6. Frequency | 7. Justify measurement or estimation and frequency |
|---|---|---|---|---|---|---|
| | Density of $CO_2$ / $\rho_{CO2}$ | kg / $m^3$ | Constant | 1.98 kg/$m^3$ at STP | 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 $CH_4$ / $\rho_{CH4}$ | kg / $m^3$ | Constant | 0.717 kg/$m^3$ at STP | N/A | Accepted value |
| | Heat Value of Acid Gas / $HV_{AG}$ | MJ / $m^3$ | Estimated | Project Engineering Design or independent laboratory gas analyses | Project Definition or Monthly Sampling | The acid gas that is being incinerated may be acid gas routed directly from the gas processing plant or may be the tail (exit) gas stream from a sulphur recovery unit.<br><br>Gas composition should remain relatively stable during steady-state operation. In cases where a pre-existing sulphur treatment process exists, an engineering report will specify the expected acid gas heat value for an appropriately sized multi-stage Claus unit. In other configurations where there is no pre-existing sulphur treatment process, only an incinerator, the heat value of the acid gas will be measured monthly by an independent laboratory. |
| | Heat Value of Fuel Gas used to Supplement Flare / $HV_{fuel}$ | MJ / $m^3$ | Measured | Direct Measurement | Monthly sampling | The term fuel gas refers to the natural gas or sales gas that is added to the acid gas stream to be flared.<br><br>Gas composition should remain relatively stable during steady-state |

| 1.0 Project/Baseline SS | 2. Parameter / Variable | 3. Unit | 4. Measured / Estimated | 5. Method | 6. Frequency | 7. Justify measurement or estimation and frequency |
|---|---|---|---|---|---|---|
| | | | | | | operation. Frequency of reconciliation provides for reasonable diligence. |
| | Heat Value of Combined Acid Gas and Fuel Gas / $HV_{combined}$ | MJ / $m^3$ | Estimated | 20 MJ / $m^3$ | N/A | This value represents the combined heat value of the acid gas stream to be incinerated and the natural gas used to supplement the flare.<br><br>Minimum value required by 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 | From Environment Canada reference documents. (Appendix A) | Annual | Reference values adjusted annually as part of Environment Canada's emissions inventory. |
| | $CH_4$ Emissions Factor for Each Type of Fuel $_{i\ CH4}$ | kg $CH_4$ per L / $m^3$ / other | Estimate | From Environment Canada reference documents. (Appendix A) | Annual | Reference values adjusted annually as part of Environment Canada's emissions inventory. |
| | $N_2O$ Emissions Factor for Each Type of Fuel $_{i\ N2O}$ | kg $N_2O$ per L / $m^3$ / other | Estimate | From Environment Canada reference documents. (Appendix A) | Annual | Reference values adjusted annually as part of Environment Canada's emissions inventory. |

### 2.5.2 Contingent Data Approaches

Contingent means for calculating or estimating the required data for the equations outlined in section 2.5.1 are summarized in **TABLE 2.5**, below.

## 2.6 Management of Data Quality

In general, data quality management must include sufficient data capture such that the mass and energy balances may be easily performed with the need for minimal assumptions and use of contingency procedures. The data should be of sufficient quality to fulfill the quantification requirements and be substantiated by company records for the purpose of verification.

The project proponent shall establish and apply quality management procedures to manage data and information. Written procedures should be established for each measurement task outlining responsibility, timing and record location requirements. The greater the rigor of the management system for the data, the more easily an audit will be to conduct for the project.

### 2.6.1 Record Keeping

Record keeping practises should include:

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

### 2.6.2 Quality Assurance/Quality Control (QA/QC)

QA/QC can also be applied to add confidence that all measurements and calculations have been made correctly. These include, but are not limited to:

a. Protecting monitoring equipment (sealed meters and data loggers);
b. Protecting records of monitored data (hard copy and electronic storage);
c. Checking data integrity on a regular and periodic basis (manual assessment, comparing redundant metered data, and detection of outstanding data/records);
d. Comparing current estimates with previous estimates as a ‘reality check’;
e. Provide sufficient training to operators to perform maintenance and calibration of monitoring devices;
f. Establish minimum experience and requirements for operators in charge of project and monitoring; and

g. Performing recalculations to make sure no mathematical errors have been made.

**Table 2.5: Contingent Data Collection 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 | Volume of Each Type of Fuel Combusted for P5 to P8 / Vol. Fuel $_i$ | L / $m^3$ / other | Estimate | Reconciliation of volume of fuel purchased within a given time period. | Monthly | Provides reasonable estimate of the parameter, when more accurate and precise method cannot be used. |
| P6 Acid Gas Dehydration and Compression | Volume of Each Type of Fuel Used / Vol. Fuel $_i$ | L / $m^3$ / other | Estimate | Reconciliation of volume of fuel purchased within a given time period. | Monthly | Provides reasonable estimate of the parameter, when more accurate and precise method cannot be used. |
| P8 Upset Flaring | Volume of Acid Gas Flared / Vol. AG Flared | $m^3$ | Estimated | Reconciliation of volume of fuel consumed within given time period based on equipment efficiency specifications and average flow rates. | Monthly | Provides reasonable estimate of the parameter, when more accurate and precise method cannot be used. |
| | Carbon Dioxide Composition in AG / % $CO_2$ | % | Estimated | Interpolation of previous and following measurements taken. | Monthly | Acid gas composition should remain relatively stable during steady-state operation. Interpolating gas composition provides a reasonable estimate when the more accurate and precise method cannot be used. |
| | $CH_4$ Composition in AG / % $CH_4$ | % | Estimated | Interpolation of previous and following measurements taken. | Monthly | Acid gas composition should remain relatively stable during steady-state operation. Interpolating gas composition provides a reasonable estimate when the more accurate and precise method cannot be used. |
| | Volume of Each Type of Fuel used to | L / $m^3$ / other | Estimated | Reconciliation of volume of fuel purchased within a | Monthly | Provides reasonable estimate of the parameter, when more accurate and precise method cannot be used. |

| | | | | | | |
|---|---|---|---|---|---|---|
| | Supplement Flare / Vol Fuel $_i$ | | | given time period.<br><br>Alternatively, the methodology used to calculate the volume of fuel used to supplement incineration in the baseline (SS B6 Incineration) may be applied. This would involve calculation of the volume of fuel used based on the heat values of the acid gas, fuel gas and combined gas streams and the volume of acid gas flared in the project condition. | | |
| P9 Injection Unit Operation | Volume of Each Type of Fuel Used / Vol Fuel $_i$ | L / $m^3$ / other | Estimated | Reconciliation of volume of fuel purchased within a given time period. | Monthly | Provides reasonable estimate of the parameter, when more accurate and precise method cannot be used. |
| P10 Recycled Gas | $CO_2$ Composition in Adjacent Gas / % $CO_2$ | % | Estimated | Interpolation of previous and following measurements taken. | Monthly | Raw gas composition should remain relatively stable during steady-state operation. Interpolating gas composition provides a reasonable estimate when the more accurate and precise method cannot be used. |
| **Baseline SS's** | | | | | | |
| B9 Fuel Extraction / Processing | Volume of Each Type of Fuel Combusted for B5 / Vol. Fuel $_i$ | L / $m^3$ / other | Estimate | Reconciliation of volume of fuel purchased within a given time period. | Monthly | Provides reasonable estimate of the parameter, when more accurate and precise method cannot be used. |

| | | | | | | |
|---|---|---|---|---|---|---|
| B6 Incineration | Volume of Gas Flared / Vol. Gas Flared | $m^3$ | Estimated | Reconciliation of volume of fuel consumed within given time period based on equipment efficiency specifications and average flow rates. | Monthly | Provides reasonable estimate of the parameter, when more accurate and precise method cannot be used. |
| | $CO_2$ Composition in AG / % $CO_2$ | % | Estimated | Interpolation of previous and following measurements taken. | Monthly | Acid gas composition should remain relatively stable during steady-state operation. Interpolating gas composition provides a reasonable estimate when the more accurate and precise method cannot be used. |
| | $CH_4$ Composition in Gas / % $CH_4$ | % | Estimated | Interpolation of previous and following measurements taken. | Monthly | Acid gas composition should remain relatively stable during steady-state operation. Interpolating gas composition provides a reasonable estimate when the more accurate and precise method cannot be used. |
| | Heat Value of Fuel Gas used to Supplement Flare / $HV_{fuel}$ | MJ / $m^3$ | Estimated | From Environment Canada reference documents. (Appendix A) | Annual | Reference values adjusted annually as part of Environment Canada's emissions inventory. |

# APPENDIX A:

**Relevant Emission Factors**

## Table A1: Emission Intensity of Fuel Extraction and Production (Diesel, Natural Gas, and Gasoline)

| | | |
|---|---|---|
| **Diesel** | | |
| **Production** | | |
| Emissions Factor ($CO_2$) | 0.138 | kg $CO_2$ per Litre |
| Emissions Factor ($CH_4$) | 0.0109 | kg $CH_4$ per Litre |
| Emissions Factor ($N_2O$) | 0.000004 | kg $N_2O$ per Litre |
| **Natural Gas** | | |
| **Extraction** | | |
| Emissions Factor ($CO_2$) | 0.043 | kg $CO_2$ per $m^3$ |
| Emissions Factor ($CH_4$) | 0.0023 | kg $CH_4$ per $m^3$ |
| Emissions Factor ($N_2O$) | 0.000004 | kg $N_2O$ per $m^3$ |
| **Processing** | | |
| Emissions Factor ($CO_2$) | 0.090 | kg $CO_2$ per $m^3$ |
| Emissions Factor ($CH_4$) | 0.0003 | kg $CH_4$ per $m^3$ |
| Emissions Factor ($N_2O$) | 0.000003 | kg $N_2O$ per $m^3$ |
| **Gasoline** | | |
| **Production** | | |
| Emissions Factor ($CO_2$) | 0.138 | kg $CO_2$ per Litre |
| Emissions Factor ($CH_4$) | 0.0109 | kg $CH_4$ per Litre |
| Emissions Factor ($N_2O$) | 0.000004 | kg $N_2O$ per Litre |

## Table A2: Emission Factors for Natural Gas and NGL's

| Source | Emission Factors | | |
|---|---|---|---|
| | **$CO_2$** | **$CH_4$** | **$N_2O$** |
| | **$g/m^3$** | **$g/m^3$** | **$g/m^3$** |
| **Natural Gas** | | | |
| Electric Utilities | 1891 | 0.49 | 0.049 |
| Industrial | 1891 | 0.037 | 0.033 |
| Producer Consumption | 2389 | 6.5 | 0.06 |
| Pipelines | 1891 | 1.9 | 0.05 |
| Cement | 1891 | 0.037 | 0.034 |
| Manufacturing Industries | 1891 | 0.037 | 0.033 |
| Residential, Construction, Commercial/Institutional, Agriculture | 1891 | 0.037 | 0.035 |
| | **g/L** | **g/L** | **g/L** |
| **Propane** | | | |
| Residential | 1510 | 0.027 | 0.108 |
| All Other Uses | 1510 | 0.024 | 0.108 |
| **Ethane** | 976 | N/A | N/A |
| **Butane** | 1730 | 0.024 | 0.108 |

### Table A3: Emission Factors for Refined Petroleum Products

| Source | Emission Factors (g/L) | | |
|---|---|---|---|
| | $CO_2$ | $CH_4$ | $N_2O$ |
| **Light Fuel Oil** | | | |
| Electric Utilities | 2830 | 0.18 | 0.031 |
| Industrial | 2830 | 0.006 | 0.031 |
| Producer Consumption | 2830 | 0.006 | 0.031 |
| Residential | 2830 | 0.026 | 0.006 |
| Forestry, Construction, Public Administration, and Commercial/Institutional | 2830 | 0.026 | 0.031 |
| **Heavy Fuel Oil** | | | |
| Electric Utilities | 3080 | 0.034 | 0.064 |
| Industrial | 3080 | 0.12 | 0.064 |
| Producer Consumption | 3080 | 0.12 | 0.064 |
| Residential, Forestry, Construction, Public Administration, and Commercial/Institutional | 3080 | 0.057 | 0.064 |
| **Kerosene** | | | |
| Electric Utilities | 2550 | 0.006 | 0.031 |
| Industrial | 2550 | 0.006 | 0.031 |
| Producer Consumption | 2550 | 0.006 | 0.031 |
| Residential | 2550 | 0.026 | 0.006 |
| Forestry, Construction, Public Administration, and Commercial/ Institutional | 2550 | 0.026 | 0.031 |
| **Diesel** | 2730 | 0.133 | 0.4 |