Technical Guidance for Completing Specified Gas Baseline Emission Intensity Applications

Version 4.0 July 2012

Specified Gas Emitters Regulation

Alberta Government

Authority:
The information provided in this document is intended as guidance to support implementation of the *Specified Gas Emitters Regulation* as provided for under section 61 of the Climate Change and Emissions Management Act (Adoption by reference).

Any comments or suggestions regarding the content of this document may be directed to:

Alberta Environment and Sustainable Resource Development
Climate Change Secretariat
12th Floor, Baker Centre
10025 106 Street
Edmonton, Alberta
T5J 1G4
E-mail: aenv.ghg@gov.ab.ca

Additional copies of this document may be obtained by contacting:

Alberta Environment and Sustainable Resource Development Information Centre
Fourth Floor, Twin Atria Building
4999 - 98 Avenue
Edmonton, Alberta T5K 2J6
Phone: (780) 427-2700 (Toll free by first dialling 310-000)
Fax: (780) 422-4086
E-mail: env.infocent@gov.ab.ca

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Abbreviations

AESRD	Alberta Environment and Sustainable Resource Development
BEI	Baseline Emissions Intensity
CCEMA	Climate Change and Emissions Management Act
CCEMF	Climate Change and Emissions Management Fund
CH_4	Methane
CICA	Canadian Institute of Chartered Accountants
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
DUNS	Data Universal Numbering System
EI	Emissions Intensity
EPC	Emission Performance Credit
EPEA	*Environmental Protection and Enhancement Act*
EUB	Energy and Utilities Board
ERCB	Energy Resources Conservation Board
FC	Fund Credit
GJ	Gigajoule
GWP	Global Warming Potential
h	Hour
HFC	Hydrofluorocarbon
HHV	Higher Heating Value
IP	Industrial Process
IPCC	Intergovernmental Panel on Climate Change
ISAE	International Standard on Assurance Engagements
ISO	International Organization for Standardization
kg	Kilogram
kJ	Kilojoule
kt	Kilotonne
LHV	Lower Heating Value
MWh	Megawatt-hour
N_2O	Nitrous Oxide
N/A	Not Applicable
NAICS	North American Industry Classification System
NEI	Net Emissions Intensity
NEIL	Net Emissions Intensity Limit
NGCC	Natural Gas Combined Cycle

NPRI	National Pollutant Release Inventory
P	Production
PFC	Perfluorocarbon
RT	Reduction Target
SF_6	Sulphur Hexafluoride
SGER	Specified Gas Emitters Regulation
SoC	Statement of Certification
SoQ	Statement of Qualification
SoV	Statement of Verification
TDE	Total Direct Emissions
TAE	Total Annual Emissions
t	Tonnes

Related AESRD Publications

- *Climate Change and Emissions Management Act*
- *Specified Gas Emitters Regulation*
- *Specified Gas Reporting Regulation*

- *Alberta's 2008 Climate Change Strategy*

- *Technical Guidance for Completing Annual Compliance Reports*
- *Additional Guidance for Cogeneration Facilities*
- *Technical Guidance for Landfill Operators*

- *Technical Guidance for Offset Project Developers*
- *Technical Guidance for Offset Protocol Developers*
- *Offset Quantification Protocols* (http://environment.alberta.ca/02275.html)

SGER Forms

- *SGER Consolidated Reporting Form*

- Landfill with partial gas collection workbook

1.0 Purpose of this document

The purpose of this document is to assist regulated facilities under the *Specified Gas Emitters Regulation* with the completion of Baseline Emissions Intensity Applications.

A facility's stated baseline emissions intensity (BEI) value must be representative of the facility's normal operating conditions. If the baseline period is not representative of that facility's standard operating conditions, the Certifying Official must contact Alberta Environment and Sustainable Resource Development to discuss an adjusted baseline period. More information on alternate baseline periods is available in section 3.2 of this guidance document.

Alberta Environment and Sustainable Resource Development recognizes that changes in operation at a facility may require the facility to restate its baseline emission intensity. Examples include, but are not limited to, detection of errors, improvements in reporting methodology, significant changes in emissions or production, changes in production technology, expansions, and decommissioning. Procedures for re-establishing a baseline are discussed in section 4.0.

Facilities that do not meet the regulatory reporting threshold, but that still wish to report their greenhouse gas emissions may do so under the *Specified Gas Reporting Program*. More information on this program is available on the Alberta Environment and Sustainable Resource Development Greenhouse Gas Reporting website at: http://environment.alberta.ca/02166.html. These facilities are also eligible to generate Emissions Offset Credits. More information on Alberta's Offset system is available at: http://environment.alberta.ca/0923.html.

1.1 Overview of Changes

The following key changes have been implemented in this version:

- Added definition of commercial operation (see section 2.2 and section 5.9.2).
- Adoption of a rolling three year baseline for new facilities (see sections 2.2 and 5.9.2).
- Added a description of negligible emissions (see section 5.1).
- Clearer definition of industrial process emissions (see section 5.2.2).
- Added a description of required reporting for CO2 entering or leaving the site (see section 5.3)
- Added description of treatment of in situ phased expansion treatment (see section 5.9.3).
- A standardized format has been established for the quantification methodology document (see sections 5.5.1 and 5.5.2).
- A partial re-write of section 6.0 on establishing baselines for sites with cogeneration.

- A number of updates have been made to and elaboration of sections 8.1 and 8.2 related to verification and the verification process including a standardized format has been established for verification reports (see section 8.2.6).
- Rewrite of section 9.0 relating to audits performed by Alberta Environment and Sustainable Resource Development.

2.0 Specified Gas Emitters Program

In 2002, Alberta passed the *Climate Change and Emissions Management Act* (the *Act*), signalling its commitment to manage the impacts of climate change and greenhouse gas emissions in the province. In 2003, Alberta passed the *Specified Gas Reporting Regulation* requiring all facilities emitting over 100,000 tonnes of carbon dioxide equivalent (CO_2e) annually to report their greenhouse gas emissions.

In 2007, Alberta passed the *Specified Gas Emitters Regulation*, reinforcing its commitment to regulate greenhouse gas emissions from large facilities. This regulation requires all facilities in Alberta emitting over 100,000 tonnes of CO_2e per year to reduce their annual emissions intensity (total annual emissions per unit of production) by 12 per cent from their 2003-2005 baseline emissions intensity. New facilities have been given a graduated reduction obligation of 2 per cent per year starting in their 4th year of commercial operations up to a reduction obligation of 12 per cent below their baseline emissions intensity. New facilities are facilities that began operation on or after January 1, 2000 and have completed less than 8 years of commercial operation.

Greenhouse gas emissions intensity is regulated on a facility-by-facility basis. Targets are set at each facility and the facility's performance over time is compared against its approved baseline emissions intensity. Alberta Environment and Sustainable Resource Development supports and encourages consistency in reporting methodologies across individual sectors. Where appropriate, sectors are encouraged to develop sector-specific reporting methodologies that improve accuracy and consistency in reporting of greenhouse gas emissions for that sector.

The *Regulation* also encourages facilities to improve emissions performance relative to production. This can be achieved through a number of initiatives, including, without limitation, incremental improvements in on-site energy use, development of emissions offset projects, and supporting development and implementation of new emissions reduction technologies.

2.1 Thresholds

The threshold for determining if a facility is subject to the *Specified Gas Emitters Regulation* has been set at 100,000 tonnes of CO_2e per year of total direct emissions. A facility's total direct emissions must include all greenhouse gas emissions sources on site, including CO_2 emissions from the combustion and decomposition of biomass and industrial process emissions. Facilities that exceed the emissions threshold in any single calendar year on or after 2003 are considered **regulated facilities**. All regulated facilities are required to establish a baseline emission intensity and submit annual compliance reports. The *Regulation* currently includes facilities in the following industrial sectors:

- Chemical Manufacturing

- Coal Mining
- Conventional Oil and Gas Extraction
- Fertilizer Manufacturing
- Mineral Product Manufacturing
- Oil Sands In Situ Extraction
- Oil Sands Mining and Upgrading
- Petroleum and Coal Products
- Pipeline Transportation
- Primary Metal Manufacturing
- Utilities
- Waste Treatment and Disposal
- Wood Product Manufacturing

Facilities which supply district energy may submit an exemption request as outlined in Section 3.3 to have emissions related to the production of district energy exempted from the requirements of the *Specified Gas Emitters Regulation*, but are still subject to the *Specified Gas Reporters Regulation* in its entirety.

2.1.1 Specified Gas Reporting Program

The Specified Gas Reporting Program is a complementary program that requires all large, industrial emitters to report their greenhouse gas emissions. More information on the Specified Gas Reporting Program is available in the Specified Gas Reporting Standard available at http://environment.alberta.ca/02168.html.

2.2 Reduction Obligations

The *Specified Gas Emitters Regulation* will require all regulated facilities to reduce their annual emissions intensity by 12 per cent below their approved baseline emissions intensity. This value is known as the net emissions intensity limit for the facility.

Established facilities are facilities that completed their first year of commercial operation on or before January 1, 2000, or that have completed eight or more years of commercial operation. Established facilities have a 12 per cent reduction obligation relative to their baseline emissions intensity.

New facilities are those facilities that completed their first year of commercial operation on or after December 31, 2000 and have completed less than eight years of commercial operation. Commercial operation is defined as operation in which a saleable end product is produced. Emissions intensity reduction obligations for these facilities are phased in over a 6-year period at rate of 2 per cent per year beginning in the fourth year of commercial operations, as depicted in Table 1 : Reduction obligation and baseline for new facilities.

The first partial year, first calendar year and second year are assumed to allow commissioning and start up of the facility. The third year forms the start of the baseline period. In the fourth year of commercial operations, the baseline emissions intensity is calculated using the facility's third year of commercial operations. In the fifth year, the baseline is calculated based on the third and fourth years. In the sixth year and beyond, the baseline is calculated based on the third, fourth and fifth years. All averaging of multi year baselines will be on a production basis rather than a time basis. Calculation of multi year baselines will automatically be completed by Alberta Environment and Sustainable Resource Development using the information submitted in compliance reports. Further guidance on calculating baseline emission intensities for new facilities is provided in Sections 5.9.2 of this document.

Reduction Target and Baseline Period for New Facilities			
Year	**Description**	**Reduction Target**	**BEI**
Start-up	Partial calendar year of initial operations	No target	No baseline
Year 1	First calendar year of commercial operation	No target	No baseline
Year 2	Second year of commercial operation	No target	No baseline
Year 3	Establish baseline	No target	No baseline
Year 4	First year reduction obligation	2% target	Year 3
Year 5	Second year reduction obligation	4 % target	Years 3,4
Year 6	Third year reduction obligation	6 % target	Years 3-5
Year 7	Fourth year reduction obligation	8 % target	Years 3-5
Year 8	Fifth year reduction obligation	10 % target	Years 3-5
Year 9	Considered an established facility	12 % target	Years 3-5

Table 1 : Reduction obligation and baseline for new facilities.

New facility treatment recognizes that newly built facilities are typically built to higher design standards than older facilities. New facility treatment under the *Regulation* recognizes these improvements by assigning a graduated compliance target for new builds. This category only applies to newly built facilities, and does not apply to facilities undergoing major modifications.

Where newly built facilities do not include a significant advancement in technology, with respect to emissions intensity, relative to older facilities in the sector, sector performance standards may be used to determine baseline emissions intensities. Sector performance standards would be developed in consultation with industry.

Options to meet emissions intensity reduction targets

Facilities that are not able to meet their reduction obligation through performance improvements (e.g. technology improvements, changes in maintenance and/or operations, etc.) may use one or more of the following compliance options:

1) Emission performance credits;
2) Offset credits; or
3) Fund credits.

More information on these compliance options is available in Section 4.0 of the Technical Guidance for Completing Specified Gas Compliance Reports.

Facilities must submit sufficient credits such that their net emissions intensity is equal to the facility's net emissions intensity limit. Net emissions intensity is calculated as total annual emissions minus the credits being submitted, all divided by annual production. Credits from each of the three true-up options listed above are counted equally at one tonne of CO_2e per credit.

Facilities that reduce their annual emissions intensity below their net emissions intensity limit are eligible to request emission performance credits, which can be banked for future use at the same facility or traded/sold to other Alberta facilities that have not met their reduction targets. Emission performance credits must be serialized by Alberta Environment and Sustainable Resource Development before they can be used as a compliance option.

3.0 Baseline Application Process

The baseline emissions intensity for a facility is established to represent **normal** historic operating conditions at the facility. This baseline emissions intensity is used to calculate the facility's Net Emission Intensity Limit. The facility's annual emissions intensity will be compared against its Net Emission Intensity Limit to assess compliance.

3.1 Normal Process

The following guide is provided to help determine whether a facility is covered by the *Specified Gas Emitters Regulation.*

1. Determine if the facility's total direct emissions, including biomass and industrial process emissions, were equal to or greater than 100,000 tonnes CO_2e in any single calendar year 2003 or later.
    - If the facility's emissions are below the 100,000 CO_2e threshold in all years since 2003, the facility is not subject to the *Regulation*. Facilities not subject to the *Regulation* are eligible to participate in the Emissions Offset program. Facilities must also determine if they are subject to the *Specified Gas Reporters Regulation*, which has a threshold of 50,000 tonnes CO2e
    - If the facility exceeded 100,000 tonnes CO_2e in any single year on or after 2003, the facility is subject to the *Regulation* and must submit a Baseline Emissions Intensity Application. The facility should contact Alberta Environment and Sustainable Resource Development as soon as possible to ensure that they are in compliance with the *Regulation*.

2. Determine the facility's baseline emissions intensity:
    - If the facility completed its first year of commercial operation before January 1, 2000, or has completed eight or more years of operation, it is considered an established facility. The facility must establish a baseline based on the years 2003-2005, or the 3rd-5th years of commercial operation, respectively.
    - If the facility completed its first year of commercial operation on or after December 31, 2000 and has completed less than eight years of commercial operation, or if the facility is designated as a new facility under subsection (2) of the *Regulation*, it is considered a new facility. New facilities should establish their baseline starting in the third year of commercial operation.
    - New facilities should refer to Table 1 to determine their baseline period.

3. Document the quantification methodology used to determine emissions in a Quantification Methodology Document, please consult Section 5.5 for more information.
4. Complete the Baseline Emissions Intensity Application form available on Alberta Environment and Sustainable Resource Development's website (http://environment.alberta.ca/01086.html).

5. Facilities that first exceed the threshold after their third year of commercial operation must submit a Baseline Emissions Intensity Application by June 1 of the year following the year they exceeded the regulatory threshold.
    - For example, if a facility exceeds the 100,000 tonne threshold in 2011, it must submit the appropriate baseline emissions intensity application by June 1, 2012. The facility must then submit annual compliance reports starting in compliance year 2012 (due March 31, 2013).

    Facilities needing to re-establish a Baseline Emissions Intensity, please consult Section 4.0 below for more information.

6. The following documents **must** be included in the facility's baseline application and should be submitted electronically:
    - Third party verified Baseline Emissions Intensity Application form,
    - Third party verifier's report ,
    - Simplified process flow diagram,
    - Identification and justification of negligible sources
    - Quantification Methodology Document
    - The signed Conflict-of-Interest Checklist,
    - The signed Statement of Certification form,
    - The signed Statement of Qualification form,
    - The signed Statement of Verification form, and
    - If required, a signed Confidentiality Request and supporting documentation.

    Alberta Environment and Sustainable Resource Development encourages the Reporter to include additional supporting documents including detailed emissions calculations, supporting data, emissions calculation methodologies references, etc. with their application. Sufficient information should be supplied to allow Alberta Environment and Sustainable Resource Development to fully understand the facility's application. Alberta Environment and Sustainable Resource Development may request additional information if needed to determine completeness and accuracy of the application. Providing sufficient supporting materials and details initially can reduce processing time required to review the facility's submission.

    All baseline applications must be third party verified to ensure accuracy of the submission. More information on verification is available in Section 8.0 of this guidance document.

    The *Electronic Transactions Act* allows for the use of electronic signatures in place of written signatures. The electronic signature must be sufficient to identify the person signing and be consistent with the purpose of the document or record being signed. Alberta Environment and Sustainable Resource Development will accept electronic signatures for the purposes of compliance under the *Specified Gas Emitters Regulation*; however, Alberta Environment and Sustainable Resource Development reserves the right to request signed originals where the electronic signature is ambiguous or cannot be verified.

E-mail submissions may be submitted electronically to **AENV.GHG@gov.ab.ca.** For administrative purposes, separate email submissions must be made for each facility.

An e-mail confirming receipt of the baseline application will be sent to the Reporter upon receipt of the application package.

If a facility is requesting confidentiality for part of its baseline application, the request, along with justification and supporting documentation, must be submitted along with the baseline application.

7. Once Alberta Environment and Sustainable Resource Development has received the Baseline Application and supporting documentation, the Director will review the application and inform the Person Responsible in writing that:
   - The baseline emissions intensity for the facility has been accepted, **or**
   - The Director has prescribed a baseline emissions intensity for the facility.

   If a request for confidentiality has been submitted, the facility will receive notification of the Director's decision within 150 days of the receipt of the confidentiality request letter. Confidentiality is discussed in more detail in Section 7.0.

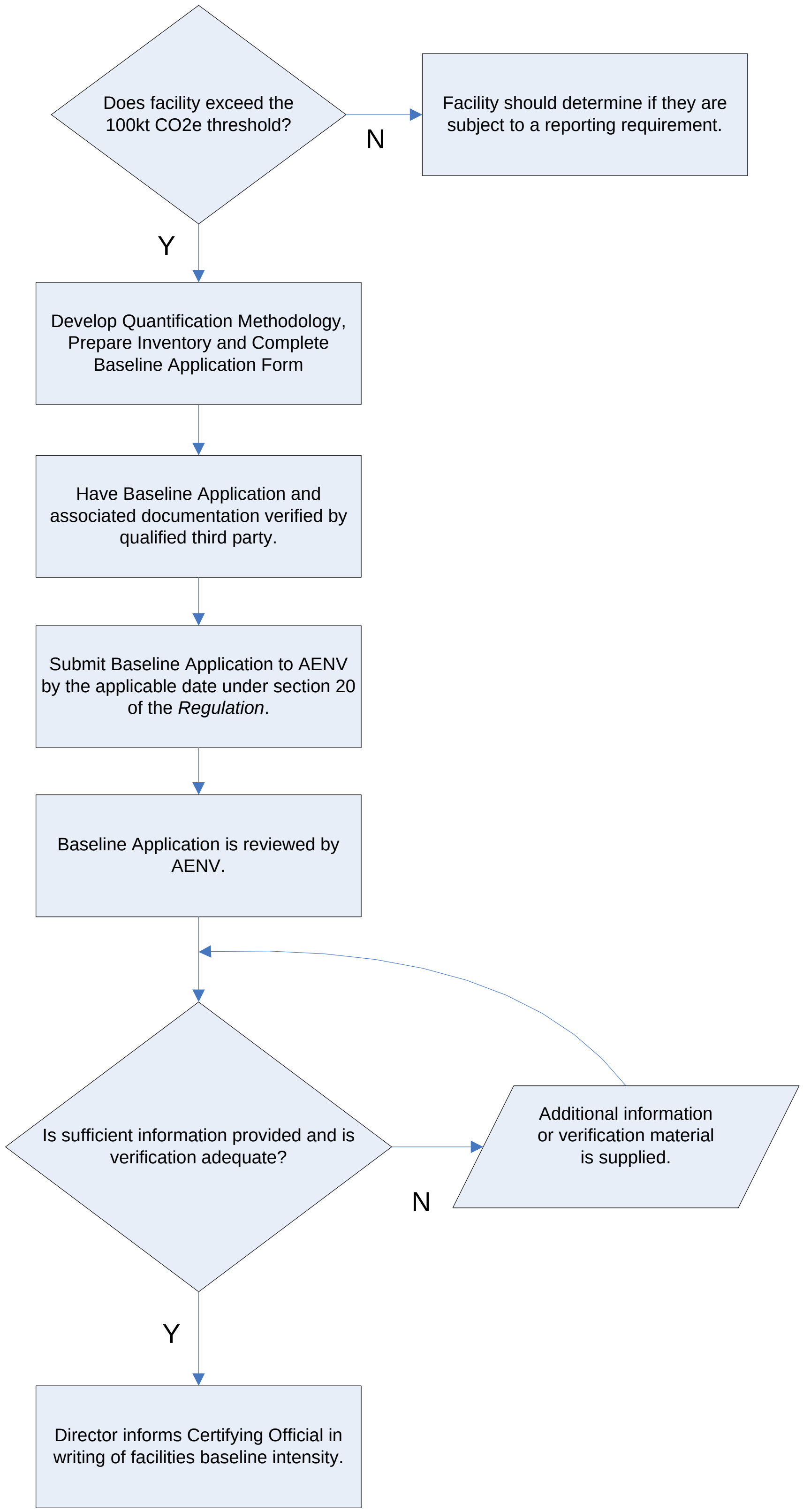

Figure 1: Baseline application process.

3.2 Alternate Baseline Applications

A facility's baseline must be representative of its normal operating conditions; however, events may occur that cause the default baseline period to be inappropriate for some facilities. Examples include:

- Where the market is depressed and the facility is operating significantly below capacity;
- Major interruption in production occurs resulting in the facility being shutdown for an extended period of time during the baseline period;
- The facility undergoes expansion resulting in changes in operation during the baseline period.

If the current baseline period is not representative of normal operating conditions or is not appropriate for a facility, the Certifying Official should contact Alberta Environment and Sustainable Resource Development to discuss the most representative and appropriate baseline period. If the facility is currently on a single year baseline a shift to a three year baseline will be considered. If both parties agree that an alternate baseline period is more appropriate for that facility, Alberta Environment and Sustainable Resource Development will prescribe a timeline for submission of a new baseline emissions intensity application using that period.

3.3 District Energy Exemption

If a facility supplies district energy, the Certifying Official may apply for an exemption of those emissions from the *Specified Gas Emitters Regulation*. If granted, the emissions related to district energy may be omitted when determining if the facility triggers the emission threshold.

Facilities involved in district energy should ask for an exemption request template from Alberta Environment and Sustainable Resource Development. It will require the facility to justify how its activity satisfies the following definition:

"District energy is the direct provision of non-industrial heating or cooling to multiple buildings from a central plant(s) through a distribution network. Multiple heating or cooling sources will be considered part of the same district energy system if they serve a common distribution network."

Facilities will also be asked to provide some data related to district energy output and emissions as part of their exemption request. In the future, Alberta Environment and Sustainable Resource Development may additionally apply a performance standard when deciding to exempt or continue to exempt emissions related to district energy.

Facilities must still comply with any and all greenhouse gas reporting requirements including the *Specified Gas Reporting Regulation*.

4.0 Re-establishing a Facility Baseline

Baselines are used as a reference point to gauge facility performance year to year. From time to time, situations may arise that make a previously stated baseline invalid. Situations may include changes in methodology, changes in operations such as the addition of new technology, expansion, or decommissioning. Facilities wishing to re-establish a baseline should consult with Alberta Environment and Sustainable Resource Development prior to submitting a revised baseline emissions intensity application. Requests for baseline re-establishment must be received by no later than June 1 of the first compliance year for which the new Baseline Emissions Intensity will apply. For example, if a facility wished to re-establish its baseline for use in comparison to the 2012 Specified Gas Compliance Report, a request must be made on or before June 1, 2012.

4.1 Methodology Change

Quantification methodology must be consistent between baseline and compliance cycles. If new methodologies become available, or if the facility implements changes that require updating its methodology, the facility should contact Alberta Environment and Sustainable Resource Development to discuss the impacts of the methodology on the approved baseline. Changes in methodology must be approved and the baseline must be restated before the methodology can be used in compliance reports.

4.2 Major Modifications

A major modification is deemed to have occurred when an existing facility that has previously reported under the *Specified Gas Emitters Regulation* undergoes a significant retrofit and change at the facility. This can include replacing pieces of equipment or installing new equipment to broaden the capacity and suite of products produced at the facility. In cases where major modifications have been made, facilities should contact Alberta Environment and Sustainable Resource Development to discuss the most appropriate path forward.

4.3 Phased Expansion

Phased expansion occurs when a facility is initially built to accommodate a series of expansion operations that have been included in its approval conditions. These facilities often exhibit a significant change in intensity over the course of the expansions. Facilities that undergo phased expansions should contact Alberta Environment and Sustainable Resource Development to discuss the most appropriate treatment. Specific guidance on phased expansion of in situ oil sands extraction facilities has been developed in consultation with the sector. More details are provided in Section 5.9.3 below.

4.4 Decommissioning

Alberta Environment and Sustainable Resource Development recognizes that production may decline more rapidly than emissions as some facilities reach the end of their operating life, causing an increase in emissions intensity. Facilities with emissions below the threshold where both production and total annual emissions are in decline, can apply for a special declining production baseline on a case by case basis by contacting Alberta Environment and Sustainable Resource Development. Facilities should propose their preferred alternative baseline according to the standard process described in Section 3.2 of this document.

Facilities whose approval status under the *Environmental Protection and Enhancement Act* (EPEA) has been amended to "decommissioned" should notify Alberta Environment and Sustainable Resource Development in order to be released from the requirements of the *Specified Gas Emitters Regulation*.

Facilities that do not have an EPEA approval must demonstrate to Alberta Environment and Sustainable Resource Development that no production or direct emissions are occurring or are planned to occur at the facility and that the facility is being decommissioned in order to be released from the requirements of the *Regulation.*

4.5 Performance Improvement

Alberta Environment and Sustainable Resource Development encourages facilities to make changes which improve emissions performance at the facility. Alberta Environment and Sustainable Resource Development will work with facilities to determine appropriate recognition of facility improvements during baseline restatements.

5.0 Estimation and Reporting of Specified Gases

The *Specified Gas Emitters Regulation* applies to any facility that has released 100,000 tonnes or more of CO_2e based on the sum of direct emissions of carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFC), perfluorocarbons (PFC), and sulphur hexafluoride (SF_6) in any year since 2003. Table 2 provides a list of the specified gases (greenhouse gases) subject to the *Regulation* including their 100-year global warming potential used to calculate CO_2e emissions.

Specified Gas	Formula	100-year GWP
Carbon dioxide	CO_2	1
Methane	CH_4	21
Nitrous Oxide	N_2O	310
Sulphur Hexafluoride	SF_6	23900
Perfluorocarbons (PFC)		
Perfluoromethane	CF_4	6500
Perfluoroethane	C_2F_6	9200
Perfluoropropane	C_3F_8	7000
Perfluorobutane	C_4F_{10}	7000
Perfluorocyclobutane	$c\text{-}C_4F_8$	8700
Perfluoropentane	C_5F_{12}	7500
Perfluorohexane	C_6F_{14}	7400
Hydrofluorocarbons (HFC)		
HFC-23	CHF_3	11700
HFC-32	CH_2F_2	650
HFC-41	CH_3F	150
HFC-43-10mee	$C_5H_2F_{10}$ (structure: $CF_3CHFCHFCF_2CF_3$)	1300
HFC-125	C_2HF_5	2800
HFC-134	$C_2H_2F_4$ (structure: CHF_2CHF_2)	1000
HFC-134a	$C_2H_2F_4$ (structure: CH_2FCF_3)	1300
HFC-143	$C_2H_3F_3$ (structure: CHF_2CH_2F)	300
HFC-143a	$C_2H_3F_3$ (structure: CF_3CH_3)	3800
HFC-152a	$C_2H_4F_2$ (structure: CH_3CHF_2)	140
HFC-227ea	C_3HF_7 (structure: CF_3CHFCF_3)	2900
HFC-236fa	$C_3H_2F_6$ (structure: $CF_3CH_2CF_3$)	6300
HFC-245ca	$C_3H_3F_5$ (structure: $CH_2FCF_2CHF_2$)	560

Table 2 : Specified Gases and Gas Species Subject to the Regulation.

5.1 Negligible Emissions

Negligible emissions are direct emissions from on-site sources that are very small in magnitude and are not expected to exceed the negligibility threshold due to variability on an annual basis. The negligibility threshold has been set at the **lesser** of 1,000 tonnes CO_2e or 1 per cent of a facility's total annual emissions, on an aggregate basis.

If the aggregate emissions total from all sources deemed to be negligible falls below the negligibility threshold, these emissions may be excluded from the total direct and total annual emissions calculation. Facilities should be aware of any changes to negligible sources that may increase emissions beyond the negligibility threshold and should notify Alberta Environment and Sustainable Resource Development of any such changes as part of their annual compliance reporting. If emissions from existing negligible sources are greater than allowed some sources should be reported as part of the total annual emissions for that period. Alberta Environment and Sustainable Resource Development may periodically request re-evaluation of a facility's negligible sources to ensure that they remain below the negligibility threshold.

If negligible emission sources exist at a facility, the following information should be provided:

In the baseline emissions intensity application:

- A conservative estimate of the magnitude and annual variation of each emission source to be treated as negligible.

In each annual compliance report:

- A list of on-site sources that existed in the compliance period that are deemed to be negligible and confirmation that these sources have not changed significantly from the baseline period; and
- A conservative estimate, as above, for any sources present in the compliance period that were not present in the baseline period.

5.2 Emissions Source Categories

Source categories have been established to facilitate reporting of specified gas emissions in all categories and the treatment of excluded emissions from certain categories. Details on the treatment of emissions from each category are provided in Sections 5.2.1 through 5.3 below.

Emissions of CO_2, CH_4, N_2O, HFC, PFC, and SF_6 must be disaggregated and reported according to the following source categories:

- Stationary Fuel Combustion
- Industrial Process
- Venting
- Flaring
- Other/Fugitive
- On-site Transportation

- Waste and Wastewater
- Formation CO_2
- CO_2 Emissions from the Combustion and decomposition of Biomass
- CO_2 geologically injected on site, received from offsite, or sent off site

Table 3 provides a general overview of relevant emissions per source category and their treatment in determining whether the facility has triggered the regulatory threshold. Industrial process emissions and CO_2 emissions from biomass are included in calculating the facility's threshold emissions, but are not included in the facility's baseline emissions calculations as described below.

Source Category	Specified Gas	Reported	Threshold (TDE)	Baseline (TAE)
Stationary Fuel Combustion (Includes CH_4 and N_2O emissions from the combustion of biomass)	CO_2, CH_4, N_2O	✓	✓	✓
Industrial Process	All	✓	✓	✗
Venting (Does not include Formation CO_2)	CO_2, CH_4, N_2O	✓	✓	✓
Flaring (Does not include flaring of landfill gas)	CO_2, CH_4, N_2O	✓	✓	✓
Other Fugitive	CO_2, CH_4, N_2O	✓	✓	✓
Formation CO_2	CO_2	✓	✓	✓
Waste and Wastewater (Includes emissions from incineration of non-biomass waste and CH_4 & N_2O emissions from decomposition of waste and CH_4 & N_2O emissions from flaring of landfill gas)	CO_2, CH_4, N_2O	✓	✓	✓
On-site Transportation	CO_2, CH_4, N_2O	✓	✓	✓
CO_2 Emissions from the Combustion of Biomass (Includes CO_2 emissions from combustion of biomass, incineration of waste biomass and flaring of landfill gas)	CO_2	✓	✓	✗
CO_2 Emissions from the Decomposition of Biomass	CO_2	✓	✓	✗
CO_2 related to capture and storage activities	CO_2	✓	✗	✗

Table 3 : Summary of Reporting Requirements by Source Category and Specified Gas.

5.2.1 Stationary Fuel Combustion

Stationary fuel combustion emissions are direct emissions resulting from non-vehicular combustion of fossil or biomass fuel (CO_2 emissions from biomass combustion are exempt but N_2O and CH_4 emissions must be reported) at the facility for the purpose of energy production (i.e. to generate electricity, heat or steam). These emissions are a common source of greenhouse gas emissions and are produced in most industrial sectors. The stationary fuel combustion source category includes on-site waste incineration if the waste is combusted for the purpose of energy production. Emissions from waste incineration when used as a disposal method must be included in the Waste and Wastewater source category.

CO_2 emissions from the combustion of biomass must be reported in a separate source category (CO_2 Emissions from the Combustion of Biomass) and included in the calculation of the emissions threshold [Total Direct Emissions (TDE)], but are not included in the calculation of total annual emissions (TAE) for the facility or the facility's compliance obligation. N_2O and CH_4 emissions from biomass combustion must be reported in the Stationary Fuel Combustion source category if their main purpose is energy production or under the Waste and Wastewater category if their main purpose is waste disposal and must be included in the total annual emissions.

5.2.2 Industrial Process

Industrial process emissions are direct emissions from an industrial process involving chemical or physical reactions, other than combustion, and where the primary purpose of the industrial process is not energy production. This includes emissions from processes in mineral, metal and chemical production. This source category is not found in all industrial sectors.

Where an industrial process involves multiple emissions sources that can be quantified separately, only the emissions meeting the definition of industrial process can be included in this category. This source category is intended to apply to industrial processes that are integral to facility production where the only option for reducing the emissions would be to scale back production. If the product of an industrial process is combusted or vented (e.g. hydrogen being used as a fuel or flared or vented rather than as a process feed stock) the emissions associated with that product are not considered industrial process emissions and must be quantified and reported under the most appropriate emissions category.

Industrial process emissions are included in the threshold emissions calculation, but are excluded from the total annual emissions calculation.

The following list contains examples of Industrial Process emissions that have been approved by Alberta Environment and Sustainable Resource Development:

- CO_2 from steam methane reforming for various uses including ammonia production
  - $CH_4 + 2H_2O \longrightarrow 4H_2 + CO_2$
- CO_2 calcination of lime stone for clinker production and quick lime production
  - $CaCO_3 \longrightarrow CaO + CO_2$
- CO_2 liberated from phosphate bearing rock exposed to acids during phosphoric acid production
- N_2O from nitric acid combustor

Facilities that are unclear on whether an emissions source meets the definition of industrial process emissions should discuss with Alberta Environment and Sustainable Resource Development before submitting their baseline application.

5.2.3 Venting

Venting emissions are direct emissions from intentional releases to the atmosphere of a waste gas or liquid stream including, but not limited to: emissions of casing gas, treater, stabilizer, dehydrator off-gas, blanket gas and emissions from pneumatic devices, which use natural gas as a driver, compressor start-up, pipeline and other blow downs and metering and regulation station control loops. Formation CO_2 emissions are not included in this source category.

5.2.4 Flaring

Flaring emissions are direct emissions from the controlled combustion of a gas or liquid stream produced on site, but not for the purpose of energy production and include, without limitation, emissions arising from waste petroleum incineration, hazardous emissions prevention systems (whether in pilot or active mode), well testing, natural gas gathering systems, processing plant operations, crude oil production, pipeline operations, petroleum refining, chemical fertilizer production, and steel production. The flaring category does not include emissions from combustion of biomass or landfill gas.

5.2.5 Other/Fugitive

Fugitive/other emissions are direct emissions that do not fit into the stationary fuel combustion, industrial process, venting, flaring, on-site transportation, waste and wastewater, formation CO_2, CO_2 from combustion of biomass, or CO_2 from decomposition of biomass categories, and include, without limitation, intentional or unintentional releases of gases arising from the production, processing, transmission, storage and use of solid, liquid or gaseous fuels.

In general, fugitive/other emissions result from the handling or processing of various types of fuel in the fossil fuel industry. Fugitive/other sources include leaks from natural gas transmission lines and processing plants, accidental releases from oil and gas wells, and releases from the mining and handling of coal.

5.2.6 Formation CO_2

Formation CO_2 emissions are direct emissions of CO_2 that are recovered or are recoverable from an underground reservoir and are gaseous at conditions under which its volume is measured or estimated. This source category includes, without limitation, CO_2 venting from gas sweetening.

5.2.7 Waste and Wastewater

Waste and wastewater emissions are direct emissions from on-site waste disposal and waste/wastewater treatment, and include emissions from landfilling of solid waste, flaring of landfill gas, treatment of liquid waste, and waste incineration, but exclude emissions from waste-to-energy operations and CO_2 emissions from decomposition and combustion of biomass.

Note that CH_4 and N_2O emissions from combustion of biomass and landfill gas are included in the Waste and Wastewater category if the combustion is not for energy production.

5.2.8 On-site Transportation

On-site transportation emissions are direct emissions resulting from fuel combustion in machinery used for the on-site transportation of products and materials integral to the production process. Examples of on-site transportation include:

- Transportation of raw or intermediate products and materials within the production process such as equipment used at an oil sands operation to mine and/or move materials to subsequent on-site processing;
- Equipment used at above or below ground mining operations to mine and/or move mined materials;
- Equipment used to transport intermediate products or materials to different on-site production processes;
- Equipment used to handle or load final product for transport; and
- Transportation of bi-products or wastes, such as mining overburden or tailings.

On-site vehicle emissions associated with emergency vehicles, staff transportation, and maintenance may optionally be excluded from the total direct emissions and total annual emissions calculations (i.e. are not required to be reported), but must be excluded or included consistently between the approved baseline emissions intensity application and associated compliance reports for each facility.

5.2.9 CO_2 Emissions from Biomass Combustion

Carbon dioxide emissions from combustion of biomass are included in this category. Biomass includes wood and wood products, charcoal, agricultural residues, trees, crops, grasses, tree litter, roots, municipal and industrial wastes where the organic material is biological in origin, landfill gas, bio-alcohols, black liquor, sludge gas, and animal or plant-derived oils. Emissions from this source category are included in the total direct emissions calculations, but not in the total annual emissions calculation.

Note that CH_4 and N_2O emissions from combustion of biomass are included in either the stationary fuel combustion category or the waste and wastewater category.

5.2.10 CO_2 Emissions from Decomposition of Biomass

Carbon dioxide emissions resulting from decomposition of biomass are included in the threshold determination and total direct emissions calculations, but not in the total annual emissions calculation.

Note that CH_4 and N_2O emissions from waste decomposition are included in the waste and wastewater category.

5.3 CO_2 related to capture and/or storage activities at the facility

Alberta Environment and Sustainable Resource Development is collecting CO_2 data for activities related to carbon capture. The following data must be reported as part of each SGER compliance report:

1) CO_2 geologically injected on site – carbon dioxide that has been injected into a geological formation from an injection point within the facility boundaries including without limitation CO_2 injected for enhanced oil or gas recovery, acid gas disposal, or CO_2 storage;

2) CO_2 received on site – carbon dioxide that has been received at the facility from an off-site location. This includes CO_2 used as a process feedstock, but does not include trace CO_2 in fuels, feedstock or products; and

3) CO_2 sent off site – carbon dioxide that has not been emitted to the atmosphere and has been sent from the facility to an off-site location. CO_2 sent off-site as waste, or sold as a product should be included.

Note: The above data fields are not included in the calculation of total annual emissions, total production, or annual emissions intensity. However, all CO_2 generated on site, including CO_2 that is sent off site, must be reported in the appropriate source category, and is included in the total annual emissions calculation based on that source category.

5.4 Reporting of Hydrofluorocarbons (HFC), Perfluorocarbons (PFC) and Sulphur hexafluoride (SF_6)

Hydrofluorocarbon (HFCs), perfluorocarbon (PFCs), and sulphur hexafluoride (SF_6) emissions occur in small volumes relative to the principle specified gases—carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O)—but have high global warming potentials. Consequently, Alberta Environment and Sustainable Resource Development requires all emissions of HFCs, PFCs, and SF_6 associated with facility production to be calculated and reported according to the following source categories:

1) **Industrial Process**: The same description of industrial process emissions as in Section 5.2.2 above applies for emissions of HFCs, PFCs, and SF_6. As with CO_2, CH_4, and N_2O, industrial process emissions of HFCs, PFCs, and SF_6 are not included in the total annual emissions calculation.

2) **Industrial Product Use**: Industrial product use emissions are all emissions of HFCs, PFCs, and SF_6 associated with production that do not meet the definition of industrial process.

Note that HFC, PFC, and SF_6 emissions associated with emergency equipment, office refrigerators, office air conditioning, and other sources not related to production are excluded from threshold and baseline emissions calculations. In cases where it is unclear which category emissions of HFC, PFC, and SF_6 belong to, Alberta Environment and Sustainable Resource Development should be contacted to discuss the matter.

5.4.1 Hydrofluorocarbons (HFC)

Hydrofluorocarbons are a family of synthetic gases that contain carbon, hydrogen and fluorine. Although emissions of hydrofluorocarbons are usually very small, species of HFCs often have large global warming potentials, ranging from 140 to 11,700 (see Table 2).

Examples of HFC sources from industrial product use include emissions from foam blowing and use of HFC as a cover gas in metal production.

5.4.2 Perfluorocarbons (PFC)

Perfluorocarbons are a family of industrial gases. Although emissions of PFC are usually very small, species of PFC have significant global warming potentials ranging from 6,500 to 9,200 times that of carbon dioxide (see Table 2).

Examples of PFC sources from industrial product use include, without limitation, emissions from aluminum production and foam blowing.

5.4.3 Sulphur Hexafluoride (SF_6)

Sulphur hexafluoride is a synthetic gas that is relatively inert due to its specific chemical properties. Emissions of SF_6 are usually small, but have a significant global warming potential of 23,900 times that of carbon dioxide (see Table 2).

Examples of SF_6 emissions from industrial product use include emissions of SF_6 used as a cover gas in magnesium smelting and casting, as foundry products in the aluminum industry, and as an insulating gas in electrical equipment such as circuit breakers and on-site power stations.

5.5 Emission Estimation Methodologies

There are several measurement and calculation options available for the different categories of emission sources. Each has an associated level of accuracy depending on the measured parameter data (e.g., fuel consumption) and the calculation method (e.g., mole balance). Where possible, Alberta Environment and Sustainable Resource Development requires the use of data and calculation methods of highest accuracy available (see Table 4 below) and should not fall below either extrapolation from historical data, or generic emissions factors respectively. Emphasis should be placed on the largest sources of greenhouse gas emissions.

For example if fuel composition data is available at a facility in both the baseline and compliance periods a site specific CO_2 emissions factor should be used rather than a generic emissions factor.

Measured Data	Accuracy*	Calculation
Monitoring or direct measurement	Most	Mole balance with efficiency factors
Intermittent (periodic) direct measurement		Equipment-specific emission factors
Calculated based on measured surrogate parameters		Manufacturer's emission factors
Extrapolated from historical data		Models based on surrogate parameters
Estimated from design requirements		Generic emission factors
Estimated from agreements	Least	Top-down emission factors

Table 4: Relative Accuracy of Emission Estimation Methodologies

* Alberta Environment and Sustainable Resource Development does not support measured data or emissions calculations that fall below the black line for the respective categories unless it is clearly demonstrated that this level of accuracy will not materially affect the facility's submission.

The following is a description of the six measured data categories in decreasing order of accuracy:

- Monitoring or direct measurement uses Continuous Emissions Monitoring Systems (CEMS). Where greenhouse gases are directly measured, a calculation methodology should speak to how data gaps are handled.
- Intermittent (periodic) direct measurements use source (stack) testing, which is a "snapshot measurement in time". Several measurements are taken periodically over the year, and each measurement is extrapolated over a period of time to determine emission values for that period of time. Intermittent (periodic) direct measurement is only considered acceptable if the frequency of measurement is sufficient to quantify all emissions sources in the category and reflect variability in the emission source better than alternative methods.
- Calculations based on surrogate measures use correlations developed between measured emission rates and related parameters. This is the most common form of measurement (e.g., fuel consumption).
- Extrapolation from historic data uses past information to determine current operating conditions (e.g., runtime and loads).
- Estimates from design requirements uses design information and facility configuration to determine likely values (e.g., power requirements for equipment determine fuel consumption).
- Estimates from agreements use contractual arrangements to provide a product or service to determine likely values (e.g. power supplied, fuel delivered).

The following is a description of the six calculation categories in decreasing order of accuracy:

- Mole balance with efficiency factors determines an emission factor based on the mole balance of carbon between the input and the output of a source, with some assumed efficiency factor.
- Equipment-specific emission factors are determined based on the measurement of the input and output of the equipment at an operating condition similar to normal operations.
- Manufacturer's emission factors are determined based on manufacturer testing.
- Models based on surrogate parameters can derive emission factors based on scientific models that do not have a parameter directly related to the emission (e.g. soil surface temperature and methane emissions from a coal pile).
- Generic emission factors based on a sample of equipment.
- Top-down emission factors based on the aggregate numbers averaged over a large population.

Alberta Environment and Sustainable Resource Development has reviewed the calculation methods listed in Table 5: Emission Calculation Methods Acceptable to and deemed them acceptable for calculating specified gases under the *Specified Gas Emitters Regulation* where they are the most accurate methods available. These calculation methods may not cover all regulated industries in Alberta. Facilities may propose facility or sector-specific calculation methodologies if it can be demonstrated the alternate calculations will result in higher accuracy and a better reflection of the facility's emissions profile. Alberta Environment and Sustainable Resource Development encourages the development of sector-specific calculation methodologies and further refinement of the approved calculation methods; however, the use of alternate calculation methodologies must be approved by Alberta Environment and Sustainable Resource Development.

Facilities using alternate calculation methodologies must include an explanation of the methodology in the Baseline Application, including a statement regarding the uncertainty associated with the calculation method. The calculation methods used **must** be consistent across all baseline years for the facility. This is to ensure that changes in the quantities of greenhouse gas emissions between years are actual changes in the quantities of greenhouse gases released and not the result of changes in methods used to calculate/estimate the facility's emissions.

Facilities must use the same calculation methods for the Baseline Application and Annual Compliance Reports. If a better, more accurate methodology is determined for a facility's annual compliance report, the facility must check with Alberta Environment and Sustainable Resource Development before using the new

methodology. As per Section 4.1 of this guidance document, changes in methodology will likely require the facility to restate its baseline emissions intensity.

Reference	Method	Stationary Fuel Combustion	Industrial Process	Fugitive	Biomass Combustion	Other (incl. Flaring and Venting, Mobile)
1	EC Sector-Specific Guidance	✓	✓			✓
2	CAPP 2005	✓	✓	✓		✓
3	CAPP 2003	✓	✓	✓		
4	CAPP 1999	✓	✓			
5	SGA 2000	✓				
6	CSA 2007	✓		✓	✓	✓
7	NCASI 3.2a	✓	✓		✓	✓
8	NCASI 3.2b	✓	✓		✓	✓
9	US EPA AP 42	✓				
10	API 2004	✓	✓	✓		✓
11	GRI-GLYCalc			✓		
12	GHG Protocol	✓	✓		✓	✓

Table 5: Emission Calculation Methods Acceptable to Alberta Environment and Sustainable Resource Development

1. Environment Canada, 2003, 2004, *Sector-Specific Guidance Manuals and Protocols (Aluminium Production, Base Metals Smelting/Refining, Cement Production, Primary Iron and Steel Production, Lime Production, Primary Magnesium Production and Casting, Metal Mining),* http://www.ec.gc.ca/default.asp?lang=En&n=95FB1C3C-1&parent=EAAE6300-7E82-407F-BCB9-43A0D5F23067, accessed June 26, 2012.

2. Canadian Association of Petroleum Producers (CAPP) and Clearstone Engineering, 2005, *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry, Volume 3 Methodology for Greenhouse Gases [2005-0013]* and *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry, Volume 5, Compendium of Terminology, Information Sources, etc. [2005-0015]*, http://www.capp.ca/library/publications/climateChange/Pages/default.aspx#6euP10EnVHyT, accessed June 26, 2012.

3. Canadian Association of Petroleum Producers (CAPP) and Altus Environmental Engineering Ltd, 2003, *Calculating Greenhouse Gas Emissions [2003-0003],* http://www.capp.ca/getdoc.aspx?DocId=55904&DT=NTV, accessed June 26, 2011.

4. Canadian Association of Petroleum Producers (CAPP) and Altus Engineering Ltd., 1999, *CH_4 and VOC Emissions from the Canadian Upstream Oil and Gas Industry – Volume 3 [1999-0011],* http://www.capp.ca/getdoc.aspx?DocId=84182&DT=NTV, accessed June 26, 2011.

5. SGA Energy Limited, 2000, *Emission Factors and Uncertainties for CH_4 and N_2O from Fuel Combustion,* www.sgaenergy.com/Experience/PE23.htm, accessed June 26, 2012.

6. Canadian Standards Association, 2007, *Canadian GHG Challenge Registry Guide to Entity & Facility-Based Reporting,* www.ghgregistries.ca/assets/pdf/Challenge_Guide_E.pdf, accessed June 26, 2012.

7. National Council for Air and Stream Improvement, Inc (NCASI), 2010, *Calculation Tools for Estimating Greenhouse Gas Emissions from Wood Product Facilities,* http://www.ncasi.org/Login.aspx?ReturnUrl=/programs/areas/climate/ghgtools/woodproducts31.aspx, accessed June 26, 2012.

8. National Council for Air and Stream Improvement, Inc. (NCASI) 2010, *GHG Calculation Tools for Pulp and Paper Mills,,* http://www.ncasi.org/programs/areas/climate/ghgtools/pulp_Canada.aspx, accessed June 26, 2012.

9. United States Environmental Protection Agency (US EPA), 1995 - 2007, *Compilation of Air Pollutant Emission Factors (AP 42) and supplements and updates*, www.epa.gov/ttn/chief/ap42/, accessed June 26, 2012.

10. American Petroleum Institute (API), 2009, *Compendium of Greenhouse Gas Emissions Estimations Methodologies for the Oil and Gas Industry,* http://www.api.org/environment-health-and-safety/climate-change/whats-new/compendium-ghg-methodologies-oil-and-gas-industry.aspx, accessed June 26, 2012.

11. Gas Technology Institute (GTI), 2000, *GRI-GLYCalc Glycol Dehydrator Emission Estimation Software,* http://www.gastechnology.org/webroot/app/xn/xd9317.html?it=enweb&xd=10AbstractPage/12352.xml, accessed June 26, 2012.

12. World Business Council for Sustainable Development (WBCSD)/World Resources Institute (WRI), 2006 - 2012, *Calculation Tools,* http://www.ghgprotocol.org/calculation-tools, accessed June 26, 2012.

5.5.1 Quantification Methodology Document

Facilities must provide a quantification methodology document using a standardized format as part of the baseline application. The document provides a brief explanation of the facilities operations and processes, boundaries, greenhouse gas sources, and the methods and assumptions used to quantify the specified gas emissions as reported.

The Facility Methodology Document MUST include:

- A description of emission estimation/calculation methodologies,
- A list of major emission sources (including the unit name and number that is used in the data management system)
- Description of the data sources which contribute to the overall quantification,
- Emission factors,
- Equations,
- Citation of reference materials (where applicable), and
- Justification for using different methodology (where applicable).

5.5.2 Format for Standardized Quantification Methodology Document

Facilities must use this format, with any additional sections included at the end of the document. The purpose of the methodology document is to provide an accurate, transparent and relatively complete overview of the facility's greenhouse gas emission sources, the greenhouse gas data and how it is used to determine the reported emissions. A standardized format improves the efficiency for verification, review and audit.

1) Facility Overview

    a. Facility Name: As it will appear in section A1 of the SGER Report.

    b. Facility Baseline Emission Intensity: (units, tonnes CO_2e/ production unit) and date of baseline assignment (once available).

    c. Facility Boundary Description: Include EPEA Approval Number(s), ERCB Number(s) and a description of which operations are included in the *SGER* Report and list any operations that are excluded with an explanation of why they are excluded. Any significant changes to the facility, the operations or the production can be listed here but must be reported in the SGER Report's section A3.

    d. Description of site processes

    e. Changes from baseline: Changes in production, emissions or emissions intensity by 10% or more or changes in operating processes, production mixes, or fuel switching (particularly when switching to grid electricity) must be reported to AESRD prior to the end of the compliance year and in section A3 of the compliance report. A baseline restatement may be required. Please provide new estimated quantification calculations and justification if changes were required. (Not applicable with baseline submission.)

2) Simplified Process Flow Diagram(s) (PFD) - the diagram(s) must provide a simple overview of the general operation and show the major material flows and emission sources labelled by source category.

3) Emission Source Categories - For each fuel/energy source, provide;
    a. List of equipment that are major sources of GHG emissions (including the unit name and number that is used in the data management system). An explanation of how the fuel/energy is received at site, where it is used and how the final use is determined (i.e. directly measured, allocated, invoiced). Provide any general supporting information such as the frequency of compositional sampling and analysis where emissions are estimated from a measured stream rate and its composition.

b. List any activity data or variables used to calculate the emissions and how the activity data are collected and translated into the reported emissions quantity (ie. the measured data /information type used and calculation category that was used for each of the calculations)

c. Show the emission calculation equation, an example calculation and list the approved reference source (See Table 5) for the calculation.

d. Show any emission factors used or calculated and list the complete reference source or method of development.

e. State any assumptions (i.e. combustion efficiency, control efficiency, thermal efficiency, etc.) with an explanation.

4) Data Management System – Include a brief explanation of how raw data moves through the data processing system and ultimately yield reported GHG emissions estimates, and the associated data quality assurance and quality control steps. Additionally, provide a brief description of how a fuel/energy source (purchased or produced) is tracked and allocated to the final emission source and rolled up to the source category (for example, onsite transportation, stationary fuel combustion, etc.) and if these volumes are reconciled back or checked against the invoice and production meters.

   a. Important Meter Tag IDs (instrument numbers) - Include a brief description of the instrument principles of measurement (type), accuracy and calibration schedule.

   b. Virtual Tag Expressions (Automated calculations that are embedded within the Information Management System) - Need to be included as part of the description of the data management system and emissions calculation equations.

5) Production - List what the various products are and how they are summed together to get a single unit (e.g. m3 Oil Equivalent) or show an example.

6) Cogeneration – Provide an explanation of the system in place, the system boundary, its inputs and the use of the steam and power. Include a simple conceptual / logic diagram, a summary of the energy balance and an explanation of how heat calculations were done, including annualized enthalpy rates. For each of the various thermal streams provide annualized flow averages, temperature averages and pressure averages for reference. If fuel factors were used to calculate the greenhouse gas emissions from cogeneration, provide the factors used including references. If fuel analysis was used to calculate greenhouse gas emissions from cogeneration, provide a synopsis of the fuel analysis. Fuel compositions, and a summary of the relevant data

used in the greenhouse gas determination are optional here if it is well covered and clearly separated under stationary fuel combustion.

7) Negligible Emission Sources - Include the calculation used for each source when estimating greenhouse gas emissions, along with a demonstration that the sources meet all requirements for negligible emissions.

8) Conversions Page - Must show any repeated calculations or conversions that are not covered elsewhere.

9) Other – Any further information that assists in explaining the greenhouse gas calculations for the facility.

Calculating a facility's Emissions Intensity

The following section provides support for calculating a facility's emissions, production and the emissions intensity. Many of the fields in the baseline emissions intensity application form are calculated automatically based on data input by the facility; however, the calculations below can assist the Reporter in checking the calculated information.

5.6 Threshold Calculation (Total Direct Emissions)

The purpose of an emissions threshold is to determine whether a facility is subject to the *Specified Gas Emitters Regulation*. All facilities in Alberta whose annual total direct emissions have exceeded 100,000 tonnes of carbon dioxide equivalent in 2003 or later are required to reduce their emissions intensity below their established baseline emissions intensity.

The total direct emissions value is the sum total of all non-negligible direct greenhouse gas emissions at a facility expressed in carbon dioxide equivalent tonnes (tonnes CO_2e). The total direct emissions value is calculated by summing the CO_2e emissions value for each greenhouse gas type reported in each source category.

5.7 Total Annual Emissions

All emissions reported in the Specified Gas Compliance Report must be calculated using an appropriate and approved methodology, as discussed in Section 5.5. All emissions must be reported in the appropriate source categories described in Section 5.2. The total annual emissions, which excludes industrial process emissions and carbon dioxide emissions from the combustion and decomposition of biomass, is automatically calculated in the reporting form.

5.8 Total Production

The total production value is the total annual quantity of saleable output, except where an output is not produced. Each facility must establish an appropriate production metric that accurately reflects the primary greenhouse gas activities and operations of the facility. In cases where multiple products are produced, all major production items associated with the release of greenhouse gases must be included and each product should be expressed in a common unit. Where possible, production should be expressed in the *International System of Units* (SI units).

The production metric should result in a stable denominator if facility operations remain unchanged. By having a stable denominator metric, facilities will be able to demonstrate real reductions in greenhouse gases as a change in emissions per unit production.

The *Specified Gas Emitters Regulation* describes production, in section 1(1), as the quantity, expressed in the applicable units of production, of

(i) end product produced by a facility, or
(ii) any input, output or other thing specified under subsection (4) of the *Regulation*.

Subsection (4) of section 1 of the *Regulation* states that:

> *If a facility* **does not** *produce an end product, the Director may specify an input, output or other thing as the standard of measurement of production of the facility for the purposes of this Regulation.*

Facilities that do not have an end product (e.g. landfills) may use an alternate production denominator, but should contact Alberta Environment and Sustainable Resource Development to discuss the most appropriate metric as part of the baseline emission intensity application process.

Facilities **must** use the same production metric for their annual compliance reports as was used in the approved baseline emissions intensity application. Alberta Environment and Sustainable Resource Development may require use of a different production metric if it is determined that the current metric does not align with the criteria described above.

Note: *Alberta Environment and Sustainable Resource Development has accepted some facility compliance submissions using alternate production metrics to calculate production. These include refinery activity index (RAI) and inlet gas. Use of these alternates is being reviewed to better understand their relevance, appropriateness, and applicability to reduction targets. Facilities using these alternate denominator metrics must also submit actual production data with their annual compliance reports.*

5.9 Calculating the Baseline Emissions Intensity

A facility's baseline emissions intensity is used as a reference point to calculate greenhouse gas emissions reductions at the facility. The baseline emissions intensity should be reflective of the facility's normal operating conditions. If the baseline period does not accurately reflect the facility's operating conditions, the Reporter should review Section 3.2 and contact the Director to discuss a more appropriate baseline period for their facility.

The baseline emissions intensity for a facility subject to the *Regulation* is calculated by dividing total annual greenhouse gas emissions by the total annual production for the facility where the total annual emissions excludes industrial process emissions, CO_2 Emissions from Combustion of Biomass, and CO_2 Emissions from the Decomposition of Biomass.

5.9.1 Established Facility

The baseline emissions intensity (BEI) for an **established facility** is determined by calculating the mean of the ratios of total annual emissions (TAE) to Production (P) for the years 2003 through 2005, as expressed in the following formula:

$$\mathbf{BEI} = \frac{\left(\frac{\mathbf{TAE_{2003}}}{\mathbf{P_{2003}}} + \frac{\mathbf{TAE_{2004}}}{\mathbf{P_{2004}}} + \frac{\mathbf{TAE_{2005}}}{\mathbf{P_{2005}}} \right)}{\mathbf{3}}$$

Where:

BEI is baseline emissions intensity;

TAE is total annual emissions for the year indicated;

P is production for the year indicated

5.9.2 New Facilities and Established *In Situ* Facilities

The baseline emissions intensity (BEI) for an **established *in situ* facility** is determined by calculating the ratio of the sum of the total annual emissions to the sum of the total annual Production (P), for the years 2003-2005, as expressed in the formula below. The baseline emissions intensity for a **new facility** is determined by calculating the ratio of the sum of the total annual emissions to the sum of the Production (P), for the appropriate years (described previously in Table 1 and shown below in Figure 2:), as expressed in the following formula:

$$\mathrm{BEI} = \frac{\sum_{i} (\mathrm{TAE} - \mathrm{Gt} + \mathrm{Dh})_i}{\sum_{i} \mathrm{P_i}}$$

Where:

BEI is baseline emissions intensity;

TAE is total annual emissions year i of commercial operation;

P is production for the year i of commercial operation;

Gt is cogeneration emissions for year i;

Dh is deemed heat emissions from cogeneration for year i;

i is the year of operation from the third full year to the fifth for new facilities, or 2003-2005 for established facilities as described in Table 1;

To minimize the reporting burden on facilities a Baseline Emissions Intensity Application will only be required after the third full year of commercial operation (the first year of the baseline period). Subsequent baselines will be calculated by Alberta Environment and Sustainable Resource Development using the existing verified baseline and compliance report submissions.

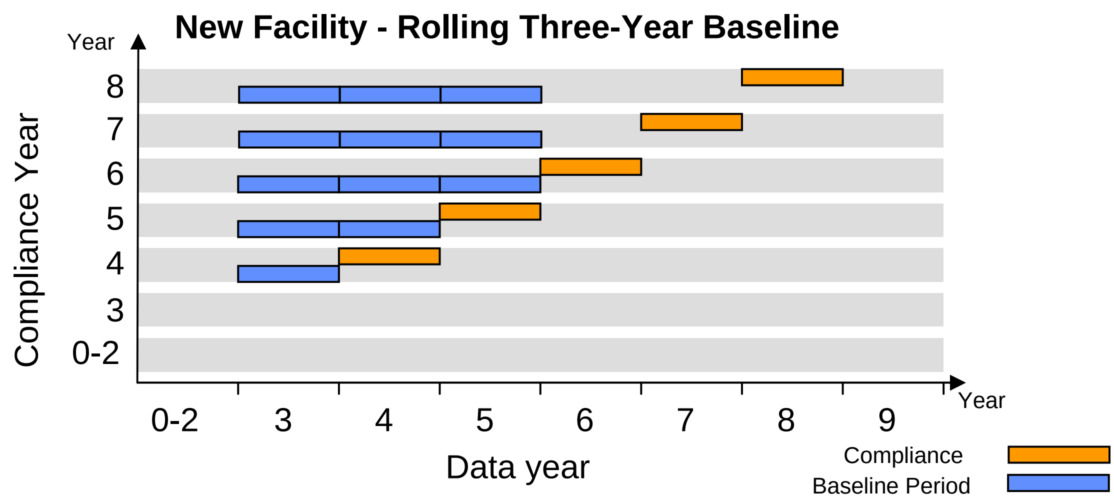

Figure 2: Rolling three year baseline for new facilities

5.9.3 *In Situ Oil Sands Extraction* Sector: Phased Facility Expansions

During expansion start up in the *in situ* oil sands extraction sector there is a period of up to a year of virtually full emissions with little to no production, which creates high emissions intensity. This occurs in all new wells, but for facilities operating at constant steam capacity, the effects are typically diluted by numerous operating wells with small numbers of wells coming online and offline simultaneously. However, when a large portion of new steam capacity (causing a significant increase in emissions as referenced below) is added to a facility there will be a large number of wells in this high intensity start-up phase at the same time, potentially swinging the facility's aggregate emissions intensity significantly relative to ongoing operation. The following policy treatment for expansions in the *in situ* extraction sector has been developed in consultation with the sector to address this situation.

To be eligible to request expansion treatment, facilities must demonstrate:

a) A significant step change in emissions (25 per cent increase or greater) associated with the addition of physical steam generation and production infrastructure **AND**;
b) The facility's emissions intensity has been affected by the expansion by more than 10% compared to the baseline emissions intensity.

To qualify, facilities must also have a clear, accurate basis for separating both the emissions and production between the expansion phase and the existing facility (i.e. separation between existing and expansion portions of the facility must be able to pass verification). Where it is not possible to separate out the emissions and production associated with the expansion, the whole facility will report against the existing baseline emissions intensity.

The emissions and production from the expansion portion of the facility associated with new equipment **AND** new areas of the reservoir (areas not impacted by previous facility operation) are submitted separately for the first partial year and the first full year of expansion operation to isolate the impact of the initial intensity spike. For the first partial year and first full year the baseline period for the expansion portion of the facility is the same as the compliance period (as shown in Figure 3: below).

If, after the first full year of operation, the original facility's baseline intensity is still a valid reference (i.e. the expansion uses similar technology and has similar reservoir characteristics) the facility may submit a single compliance report for the whole site.

If, after the first full year of operation, it is determined that the original baseline is not still a valid reference a new baseline will be assigned. This baseline will be a combined representative baseline for the entire facility which can roll into a three year production weighted average as shown in Figure 3:, similar to the establishment of baseline emission intensities for new in situ facilities. As an example, for expansion year 2 in Figure 3:, the baseline intensity would be calculated as total emissions for the existing facility baseline plus total emissions for the expansion phase in year 2 divided by total production in existing facility baseline plus total production for the expansion phase in year 2. Facilities will submit separate compliance reports for their expansion(s) and the remainder of their facility until year 6 in Figure 3:. In year 6 the facility will again submit a combined compliance report for the entire site.

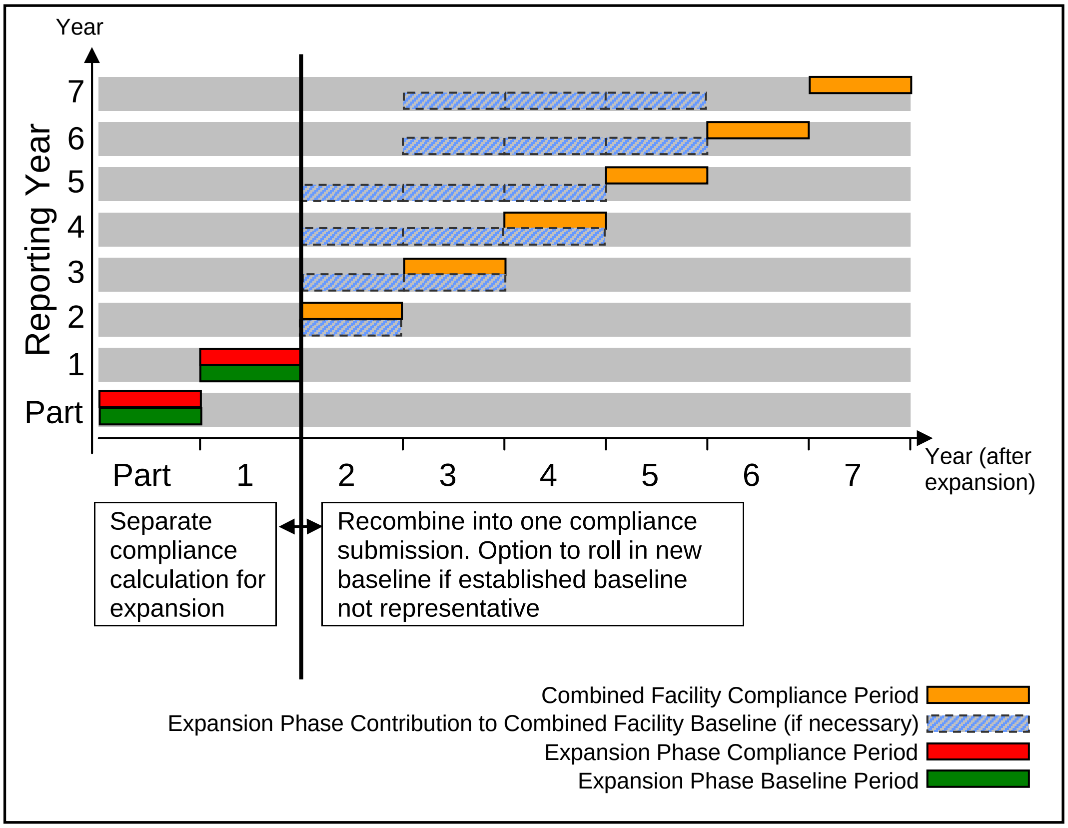

Figure 3: Baseline for phased expansion of in situ oil sands extraction facilities

Baseline Period example for expansions at *In Situ Oil Sands Extraction* facilities				
Year	**Description**	**Reduction Target**	**New Facility BEI**	**Expansion BEI**
2005 (Start-up)	Partial calendar year of initial operations	No target	No baseline	n/a
2006	First full calendar year of commercial operation	No target	No baseline	n/a
2007	Second year of commercial operation	No target	No baseline	n/a
2008	Establish baseline	No target	No baseline	n/a
2009	First year reduction obligation	2% target	2008	n/a
2010	Second year reduction obligation	4 % target	2008, 2009	n/a
2011 (expansion start up)	Third year reduction obligation, first partial year of expansion operation	6 % target	2008 - 2010	2011
2012	Fourth year reduction obligation, first full year expansion operation	8 % target	2008 - 2010	2012
2013	Fifth year reduction obligation, second full year expansion operation	10 % target	2008 – 2010 main facility, 2013 expansion phase	
2014	Considered an established facility, third full year expansion operation	12 % target	2008 – 2010 main facility 2013-2014 expansion	
2015	fourth full year expansion operation	12 % target	2008 – 2010 main facility, 2013-2015 expansion	

2016	fifth full year expansion operation	12 % target	2008 – 2010 main facility, 2013-2015 expansion
2017	Blended BEI may become fixed at this point Facility can again file a single compliance report.	12 % target	2008 – 2010 main facility, 2014-2016 expansion
2018	Facility files single compliance report.	12 % target	2008 – 2010 main facility, 2014-2016 expansion

Table 6 : Example Reduction obligation and baseline for *In Situ Oil Sands Extraction* facilities.

6.0 Cogeneration

The following section provides guidance on submitting baseline applications for facilities that include integrated cogeneration or provide stand alone cogeneration.

Cogeneration is the combined production of heat for use in industrial facilities and electricity. Electricity not used within the plant may be offered to the competitive electricity market. Combined use of heat in production and to generate electricity improves the overall efficiency of the plant and can displace higher emitting coal-generated electricity. Treatment of cogeneration under the *Specified Gas Emitters Regulation* recognizes the environmental benefit associated with the higher energy efficiencies generally afforded by cogeneration operations and also the low intensity production of electricity.

For facilities with cogeneration, baseline intensities are established by including only cogeneration emissions that are deemed to have been necessary for heat generation. Calculations in the compliance period differ from those in the baseline period in order to credit cogeneration for emissions savings versus stand alone alternatives represented by an 80 per cent efficient boiler and a natural gas combined cycle electricity generator running at 0.418 tCO_2e/MWh.

6.1 Definitions

Standalone cogeneration facilities are those units that derive all their energy outputs from on-site fuel combustion. These units do not have any other external energy inputs. All the thermal and electrical output should be traced down to a single source. All emission from a standalone facility should be from cogeneration related equipment. The production from standalone cogeneration facilities is Heat (H), as described in 6.4.1.

Integrated cogeneration facilities are those units that, in addition to their own fuel source, also have other sources contributing to generating thermal or electrical output. This source could be combustion at the host site, any exothermic reaction or in some cases import or export of steam from a second heat source depending upon demand.

6.2 Cogeneration Reporting Requirements

Reporting requirements for cogeneration facilities differ from reporting requirements for regular facilities. Additional reporting is required to recognize the environmental benefits of the combined generation of heat and electricity at a facility. Facilities file as having cogeneration must provide the following information in the Baseline Emissions Intensity Application Form:

- Total greenhouse gas emissions (G_T) in tonnes CO_2e from the cogeneration facility in the baseline year(s);
- Actual fuel used by the cogeneration in the baseline year(s);
- Total net heat production (H) in GJ produced by the cogeneration facility in the baseline year(s);
- Mass/volume of fuel deemed used to produce heat in the baseline year(s);

- Deemed greenhouse gas emissions from heat production (D_H) in tonnes CO_2e in the baseline year(s);
- Total net electricity production (E) in MWh by the cogeneration facility in the baseline year(s);
- Deemed greenhouse gas emissions from electricity generation (D_E) in tonnes CO_2e in the baseline year(s); and

The reporter must also provide the following information in their quantification methodology document:

- A simple conceptual/logic diagram of the cogeneration layout including the boundary and control volume used for heat calculations;
- A description of the cogeneration boundary and control volume used for calculations;
- An explanation of how heat calculations were done, including how the enthalpies were averaged;
- Listing of the various thermal streams and annualized flow averages, temperature averages and pressure averages for each stream;
- Hours of operation of the cogeneration facility in the baseline year(s).

6.3 Cogeneration Greenhouse Gas Emissions

Greenhouse gas emissions from cogeneration are calculated like other stationary fuel combustion sources. Fuel used for cogeneration needs to be clearly separated from other fuel use at the facility.

Note that carbon dioxide (CO_2) emissions from biomass are not included in the cogeneration emissions calculations. Treatment of CO_2 emissions from biomass is discussed in Section 5.2.9.

6.4 Deemed Greenhouse Gas Emissions from Heat Generation

Deemed greenhouse gas emissions are calculated according to the methodology outlined below.

6.4.1 Standard Calculation Methodology for Determining Heat Production from the Facility

The mass energy balance principle is an acceptable calculation methodology for calculating net heat production from a cogeneration facility. Mass energy balance can capture all the components of the heat and steam exchange and quantify the heat transfer at large facilities where the host facility and cogeneration unit are interconnected through various thermal streams that help with the exchange of different types of steam.

The net heat produced by the cogeneration facility is calculated based on the difference between:

- The total energy content of the thermal streams leaving the cogeneration boundary; and
- The total energy content of the thermal streams entering the cogeneration boundary.

These values would be aggregated over the reporting period to calculate a total net heat.

The calculation is carried out as follows:

$$\mathbf{H} = \sum_{i=1}^{n} \{\mathbf{h(out)_i} \times \mathbf{M(out)_i}\} - \sum_{i=1}^{m} \{\mathbf{h(in)_i} \times \mathbf{M(in)_i}\}$$

Where:

H	=	Heat produced by the cogeneration facility	[kJ]
$h(out)_i$	=	Enthalpy of i stream of steam to the steam host	[kJ/kg]
$h(in)_i$	=	Enthalpy of i stream of condensate returned to the cogeneration unit	[kJ/kg]
$M(out)_I$	=	Mass flow of i stream of steam	[kg]
$M(in)_i$	=	Mass flow of i streams of condensate	[kg]
n	=	Total number output steam streams	
m	=	Total number of input condensate streams	

Enthalpies and mass flows should be calculated using data of the finest time scale available then summed over the year.

Where the cogeneration facility has a more complex heat transfer profile, these sites should calculate their net heat production based on their actual heat balance.

6.4.2 Calculate the Deemed Greenhouse Gas Emissions for Heat Production

Deemed emissions from heat production are determined from the input energy attributed to heat production based on a boiler thermal efficiency of 80 per cent on a higher heating value basis. This input energy is the energy derived from fuel combustion that is attributable to useable heat production.

$$E_H = \frac{H}{0.8}$$

Where:

E_H	=	Deemed input energy attributed to heat production	[GJ]
H	=	Total heat produced within the cogeneration boundary during the baseline year(s)	[GJ]

Next, calculate the fuel required to generate the deemed input energy.

$$M_H = \frac{E_H}{V}$$

Where:

M_H	=	Mass/volume of fuel deemed to be used to produce heat	[units of fuel used]
V	=	Fuel Higher Heating Value	[GJ/units of fuel used]

Where multiple fuel sources are used each source should be apportioned a fraction of deemed input heat equal to the fraction of total fuel heat provided by the fuel source on a higher heating value basis.

The deemed greenhouse gas emissions allocated to heat production are calculated according to:

$$\mathbf{D_H = F \times M_H}$$

Where:

D_H	=	Deemed greenhouse gas emissions from heat production	[tonnes CO_2e]
F	=	Emission factor for the fuel used in the stand-alone boiler facility.	[tonnes CO_2e/units of fuel used]

Emissions factors for calculating deemed greenhouse gas emissions from heat should be developed using the most accurate method available for the fuel used consistent with section 5.5.

6.4.3 Measure the Total Electricity Generated by the Cogeneration Facility

Deemed emissions associated with electricity generation are calculated based on electrical generation. That is, the calculation should account for the net electricity that crosses the cogeneration boundary (exported to the host facility and the electricity grid). This calculation of electrical generation should be net of station loads (i.e. loads integral to the function of the cogeneration unit).

6.4.4 Calculate the Deemed Greenhouse Gas Emissions for Electricity Generation

Deemed greenhouse gas emissions for a cogeneration facility are based on a Natural Gas Combined Cycle turbine with a deemed greenhouse gas emissions intensity of 0.418 tonnes CO_2e/MWh. These emissions are calculated according to the following formula:

$$\mathbf{D_E = 0.418 \times E}$$

Where:

D_E	=	Deemed greenhouse gas emissions from electricity generation	[tonnes CO_2e]
E	=	Total electricity generation by the cogeneration facility during the baseline year(s).	[MWh]

6.5 Baseline Intensity

A facility with cogeneration will be assigned an adjusted intensity which reflects the intensity that would have occurred if a reference boiler had been installed instead of cogeneration.

$$BEI = \frac{(TAE - G_T) + D_H}{P}$$

For stand alone cogeneration operations heat will be taken as the facility product and TAE will be equal to Gt in the above equation.

If there are multiple baseline years, the emissions and production for all years are averaged to determine the baseline intensities.

7.0 Data Confidentiality and Access to Information

7.1 Request for Confidentiality

In accordance with section 16 of the *Regulation*, facilities may request certain information in the specified gas baseline application be kept confidential for a period of up to five years on the basis that the information is commercial, financial, scientific or technical information that would reveal proprietary business, competitive or trade secret information about a specific facility, technology or corporate initiative. Confidentiality can be granted to specific information contained in portions of the baseline application, but cannot be granted for the entire baseline application.

To request confidentiality, **a written request must be included with the baseline application that clearly states the specific information to be kept confidential, including justification for each piece of information**. If additional information is requested from the facility by Alberta Environment and Sustainable Resource Development as part of the baseline application review, the facility may also submit a written request for confidentiality of this information at that time, with appropriate justification for the request.

Each confidentiality request will be reviewed by Alberta Environment and Sustainable Resource Development and a decision will be rendered by the Director within 150 days from the letter of submission date. During this time, the portions of the information for which confidentiality has been requested will be considered prescribed information under the *Freedom of Information and Protection of Privacy Act*. The confidentiality request and evaluation process is illustrated in Figure 4: below.

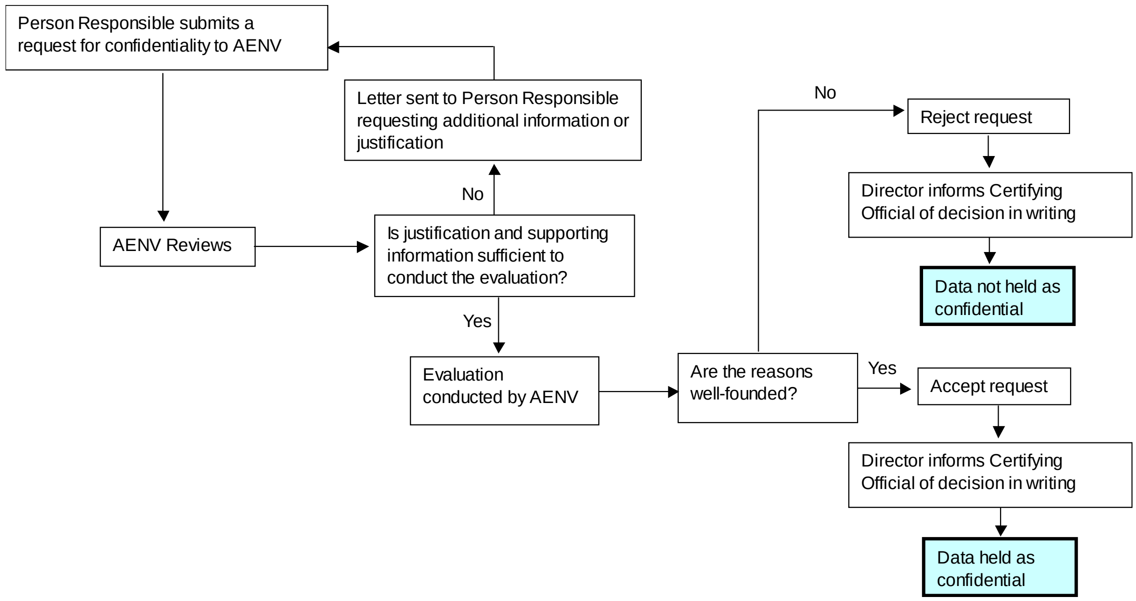

Figure 4: Confidentiality process for the Specified Gas Emitters program

In accordance with section 17 of the *Regulation*, the Director must submit an annual confidentiality report to the Information and Privacy Commissioner. This report must include the number of confidentiality requests received, number of confidentiality requests approved, and the period of time prescribed for each approved request.

Note: *Alberta Environment and Sustainable Resource Development cannot guarantee confidentiality regarding information for which confidentiality has not been requested.*

7.2 Use of Baseline Application Information

Alberta Environment and Sustainable Resource Development will publish information that is collected through the *Regulation* on a regular basis. Such publications will include facility-level data reported in the baseline application, including, without limitation, total annual emissions and annual emissions intensity. Prescribed (confidential) information may be published in aggregate form such that individual facility information cannot be identified.

Non-confidential information contained in the baseline application or compliance report may be published in any form or manner the Director considers appropriate.

7.3 Access to Baseline Application Information

Accordance to section 13 of the *Specified Gas Emitters Regulation,* persons wishing to access baseline or compliance information that has not been deemed confidential may submit written requests for information directly to the facility. The facility must respond in writing within 30 days of receiving the request. If the facility does not release the requested information, the persons seeking the information may submit a request, including a copy of the correspondence with the facility, to the Director. Alberta

Environment and Sustainable Resource Development will review all requests for information and release information *that has not been granted confidentiality*. Figure 5: shows the process for requesting access to information reported under the *Regulation*.

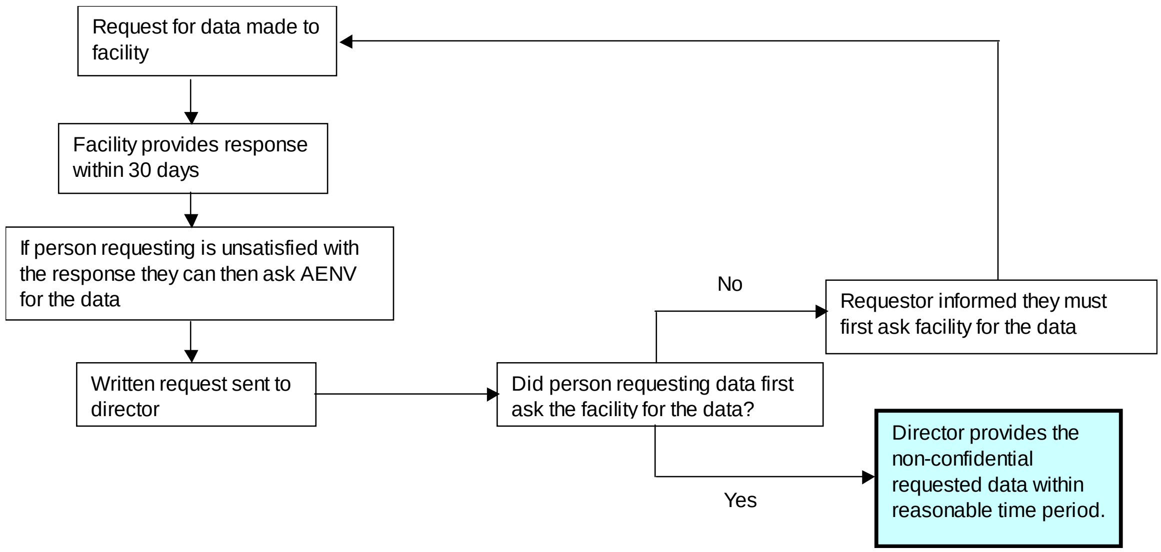

Figure 5: Process for requesting non-confidential information reported under the Specified Gas Emitters Regulation

8.0 Verification by Third Party Verifier

Third party verification is intended to provide an independent review of each facility's baseline application before it is submitted to Alberta Environment and Sustainable Resource Development. This review provides additional assurance that the baseline applications received are reliable and of sufficient quality to determine the facility's baseline emissions intensity.

The requirement for third party verification is consistent with international standards requiring independent, third party verification for greenhouse gas inventories. The Third Party Verifier's report is used for information purposes to assist Alberta Environment and Sustainable Resource Development in reviewing and understanding the facility's submission. Third Party review should flag discrepancies in reported data, identify areas where the interpretation in the reported data differs from the guidance provided by Alberta Environment and Sustainable Resource Development, and quantify material and immaterial discrepancies encountered. Facilities are encouraged to review the verification findings, and where possible, make corrections to their submission prior to submitting their baseline application. This ensures greater accuracy and correctness in the final submission. However, the audience for the Third Party Verifier's Report is Alberta Environment and Sustainable Resource Development. As such, this report must meet the requirements outlined in this section. Third Party Verifier's reports that do not meet these requirements may be deemed incomplete. Incomplete reports will not be accepted by Alberta Environment and Sustainable Resource Development and could result in the facility's baseline application being considered incomplete and the facility being deemed out of compliance with the *Specified Gas Emitters Regulation*.

Alberta Environment and Sustainable Resource Development will conduct an annual audit on up to 10 per cent of the baseline applications received. Alberta Environment and Sustainable Resource Development's audit process is described in more detail in Section 9.0.

8.1 Verification Fundamentals

8.1.1 Terminology

Assurance refers to the confidence level that a third party verifier uses to express a written conclusion concerning a facility's compliance assertion.

Compilation refers to completion of a facility's baseline application submission, which may be done internally by the reporting company or by a qualified external body contracted by the reporting company. Third party verifiers cannot provide compilation or consulting and third party verification services for the same compliance assertion.

Compliance Assertion refers to the information being verified. In the case of baseline application submissions, the compliance assertion is the greenhouse gas emissions, production quantities, cogeneration data, and emissions intensity value reported in the Specified Gas Baseline application.

Designated signing authority refers to an individual who has binding authority for the verification company. This person must meet the requirements of section 18 of the *Specified Gas Emitters Regulation.* This person's signature is provided on behalf of the verification team on the statement of qualifications, statement of verification, and conflict of interest checklist.

Lead verifier is the individual leading the verification team. This person is responsible for coordinating the verification and ensuring that appropriate expertise is available to review all aspects of a facility's baseline application.

Limited assurance (or negative assurance) is a moderate level of assurance. Limited assurance is based on identifying anomalies rather than confirming an assertion.

Materiality refers to a threshold measure for the cumulative magnitude of errors, omissions, discrepancies, and misrepresentation that affect an assertion. Materiality is discussed further in Section 8.1.8.

Peer reviewer is an independent qualified professional who reviews the third party verification. This person cannot be the lead verifier.

Reasonable assurance (or positive assurance) is a high level of assurance. Reasonable assurance is a direct factual statement expressing the opinion of the verifier.

Third party verifier describes the person or persons conducting the independent, third party verification of the facility's submission.

Verification describes the process used by a third party verifier to comment on a conclusion regarding a facility's compliance assertion.

8.1.2 Qualifications of the Third Party Verifier

The Third Party Verifier (lead verifier and verification team) is defined as a qualified person or persons that make up a verification team that verifies and provides assurance on a facility's baseline application.

The designated signing authority is an individual capable of binding the verification company. This person must be an accountant registered under the *Alberta Regulated Accounting Profession Act* (or equivalent) or a professional engineer registered under the *Engineering, Geological and Geophysical Professions Act* (or equivalent), and must be in good standing with the associated professional organization. The designated signing authority must sign and submit the statement of qualification, statement of verification, and conflict of interest checklist provided in the baseline application form.

The lead verifier must be able to demonstrate training in one of the three acceptable verification standards discussed in Section 8.1.5. The lead verifier may also be the designated signing authority, but cannot be the peer reviewer.

The verification team must have technical expertise and competency in the following areas:

- Data audit practices and data verification standards
- The *Specified Gas Emitters Regulation* and associated requirements
- Verification criteria and their appropriate application within the defined scope of the verification
- Sector-specific areas, including:
  - Knowledge of specific greenhouse gas activities and technologies
  - Identification and selection of greenhouse gas sources, sinks, and reservoirs
  - Quantification, monitoring and reporting, including relevant technical and sector issues
  - Situations that may affect the emissions intensity value during typical and atypical operating conditions

The designated signing authority must be an individual capable of binding the verification company, must be either an accountant registered under the *Alberta Regulated Accounting Profession Act* (or equivalent) or a professional engineer registered under the *Engineering and Geoscience Professions Act* (or equivalent), and must be in good standing with the associated professional organization.

The *Electronic Transactions Act* allows for the use of electronic signatures in place of written signatures. The electronic signature must be sufficient to identify the person signing and be consistent with the purpose of the document or record being signed. Alberta Environment and Sustainable Resource Development will accept electronic signatures for the purposes of compliance under the *Specified Gas Emitters Regulation*; however, Alberta Environment and Sustainable Resource Development reserves the right to request signed originals where the electronic signature is ambiguous or cannot be verified.

Note: Signatures on behalf of a corporation are not acceptable under the *Specified Gas Emitters Regulation*, which requires the third party verifier to be an individual. If a verifier wishes to sign on behalf of a corporation, sign-off maybe completed as follows:

Company Name
Per [name and signature of Corporate Binding Official]

8.1.3 Accreditation of verifiers

Alberta has commissioned a joint task force to review different audit standards and the implications of third party verifier accreditation in order to support the change to requiring reasonable assurance verification. The results of this work will be available in 2012.

8.1.4 Independence

Independence is a surrogate measure for the objectivity of the verifier and is a key qualification of a Third Party Verifier. The Third Party Verifier must be able to demonstrate independence and have the appropriate systems in place to document this independence in order to be qualified for third party verification.

The following threats to independence should be assessed by both the facility and third party verifier before the third party verification is commenced:

1. **Self-interest threat**: This occurs when the verifier or a member of the verification team or a person in the chain of command for the verification could directly benefit from a financial interest in the verification client, or when there is any other self-interest conflict with respect to the verification client. For example:

    - Owning shares of the verification client;
    - Having a close business relationship with the client;
    - Contingent fees relating to the results of the engagement;
    - Potential employment with the verification client; or
    - Undue concern about the possibility of losing the verification or other fees from the client.

2. **Self-review threat**: This occurs when a member of the verification team could be in a position of reviewing his or her own work. For example:
    - Involvement of the verification organization in the compilation of the data contained in the assertion, including documentation.
    - A verification organization member performing non-verification services that directly impinge on the client's assertion, such as implementing the greenhouse gas or production data management systems; and
    - A member of the verification engagement team having previously been a greenhouse gas or production data compiler of the verification client or who was employed by the verification client in a position to exert direct and significant influence over the client's assertion being reviewed.

3. **Advocacy threat:** This occurs when a verifying organization or a member of the verification team or a person in the chain of command for the verification promotes, or may be perceived to promote, a verification client's position or opinion to the point that objectivity may, or may be perceived to be, compromised. For example:
    - Dealing in, or being a promoter of, emission performance credits on behalf of a verification client; and
    - Acting as an advocate on behalf of the verification client in litigation or in resolving disputes with third parties.

4. **Familiarity threat:** This occurs when, by virtue of a close relationship with a verification client, its directors, officer or employees, the firm or a member of a verification engagement team becomes too sympathetic to the client's interests. For example:

- A person on the verification team has a close personal relationship with a person who is in a critical greenhouse gas or production compilation role at the verification client; and
- Acceptance of significant gifts or hospitality from the verification client.

5. **Intimidation or economic dependence threat**: This occurs when a member of the verification team or a person in the chain of command is deterred from acting objectively and exercising professional skepticism by threats, actual or perceived, from the directors, officers or employees of the verification client. For example:
   - The threat of being replaced as third party verifier due to a disagreement with the application of greenhouse gas quantification methodology;
   - Fees from the verification client represent a large percentage of the overall revenues of the third party verifier.
   - The application of pressure to inappropriately reduce the extent of work performed in order to reduce or limit fees; and
   - Threats arising from litigation with a verification client.

If it is determined that there is a real or potential conflict of interest, and both parties wish to pursue the engagement, written evidence must be provided to Alberta Environment and Sustainable Resource Development prior to the verification describing the actions that will be taken to manage the potential conflict in order to preserve actual and perceived independence. Alberta Environment and Sustainable Resource Development will assess all potential conflict of interest cases. In cases where it determined that a potential conflict of interest cannot be effectively managed, facilities will be required to select an alternate third party verifier.

Impartiality must be monitored throughout the verification process. If an actual or perceived conflict of interest is identified, the facility must notify Alberta Environment and Sustainable Resource Development and work with the third party verifier to manage the conflict.

Alberta Environment and Sustainable Resource Development recognizes that some familiarity with a facility and its processes is helpful in reviewing a facility's compliance report or baseline emissions intensity application; however, Alberta Environment and Sustainable Resource Development also recognizes that a close relationship between facilities and verifiers can compromise a third party verifier's impartiality over the long term. Consequently, Alberta Environment and Sustainable Resource Development has implemented a limitation whereby facilities must not acquire verification services from the same lead verifier or verification company for more than five compliance cycles without an interval of two consecutive compliance cycles. Note that a facility's initial baseline emissions intensity application is considered a compliance cycle, but resubmission of a previous compliance report or baseline emissions intensity application is not considered an additional compliance cycle.

Note: *In certain situations, Alberta Environment and Sustainable Resource Development may require the use of a new or a different third party verifier prior to the five year limit. Examples of when this may be required include, but are not limited to, adverse audit conclusions or multiple restatements of compliance and/or baseline submissions.*

8.1.5 Verification Standards

Third Party Verifiers must use one of the following verification standards and must be able to demonstrate how they meet the qualifications for the standard being used:

- ISO 14064 Part 3 – Greenhouse Gases: Specification with guidance for the validation and verification of greenhouse gas assertions
- Standards for Assurance Engagements, Canadian Institute of Chartered Accountants (CICA) Handbook – Assurance Section 5025
- International Standard on Assurance Engagements (ISAE) 3000 - Assurance Engagements Other Than Audits or Reviews of Historical Financial Information

These standards ensure a consistent level of rigour in the verification process such that a peer verifier or auditor would come to the same conclusion as the original verifier.

The following documents provide guidance to assist the verifier in completing the third party verification:

- *Climate Change and Emissions Management Act*
- *Specified Gas Emitters Regulation*
- *Technical Guidance for Completing Specified Gas Compliance Reports*
- *Technical Guidance for Completing Specified Gas Baseline Emissions Intensity Applications*
- *Additional Guidance on Cogeneration Facilities*
- *Technical Guidance for Offset Project Developers*

8.1.6 Verification Criteria

Verification criteria will be established by the third party verifier prior to the site visit. Criteria must be set to test that the facility's baseline application adheres to the regulatory requirements in the *Regulation,* and that emissions and production were correctly calculated in a transparent and replicable manner. As such, verification criteria will vary between facilities. An overview of the verification criteria and sampling plan should be appended to the verification report.

8.1.7 Peer Review Process

Peer review is a required part of verification under the *Regulation*. The peer review process requires that persons different from those who undertook the verification work (i.e. assessed the greenhouse gas information system and its controls, the greenhouse gas data and information, and conducted the assessment against the verification criteria) perform a final evaluation of the evidence and conclusions of the verification team.

The name and qualifications of the peer reviewer must be provided in the verification report along with the members of the verification team. Note that the peer reviewer may also be the designated signing authority, but cannot be the lead verifier or have been involved in the verification work.

8.1.8 Materiality

Materiality refers to a threshold for errors, omissions, and misrepresentations (discrepancies) in a facility's compliance assertion. Materiality affects a third party verifier's ability to issue a statement of verification. The materiality threshold for compliance with the *Regulation* has been set at two different levels, depending on the facility's total annual emissions in the verification period, as shown in Table 7.

Total Annual Emissions	Materiality Threshold
< 500 kt CO_2e	5 per cent
≥ 500 kt CO_2e	2 per cent

Table 7: Materiality threshold levels for baseline application submissions.

Materiality is assessed on the total magnitude of the errors, omissions or misrepresentations, regardless of the combined effect of overstatements and understatements. For example, a 3 per cent overstatement combined with a 3 per cent understatement in emissions would result in a 6 per cent combined discrepancy in the facility's submission. This is considered a 6 per cent material discrepancy despite having a net zero impact on the compliance submission.

Third party verifiers cannot issue a statement of verification for a compliance assertion that contains unresolved material discrepancies. Material discrepancies must be resolved before a verification statement may be issued.

Discrepancies under the materiality threshold are deemed **immaterial**. These discrepancies are assessed on a case-by-case basis to determine appropriate corrective action. A third party verifier may issue a statement of verification for a compliance submission that has unresolved immaterial discrepancies; however, unresolved immaterial errors must be identified and detailed in the verification report.

Discrepancies can be further categorized as either quantitative or qualitative. **Quantitative discrepancies** are those of a numerical nature, where the magnitude of the discrepancy can be estimated or calculated to a reasonable degree of accuracy. Examples include input data inaccuracies, omission of sources, and inappropriate application of calculation methodology.

Quantitative discrepancies are assessed against the materiality threshold on an aggregate of magnitudes basis, regardless of the combined effect of overstatements and understatements, in the following way:

1. Each individual discrepancy is calculated on a percentage basis. Emissions discrepancies are calculated as percent of total annual emissions, and production discrepancies as a percent of total production:

$$\% \ Discrepancy = \frac{|TAE_{reported} - TAE_{corrected}|}{TAE_{corrected}} \times 100\%$$

OR

$$\% \ Discrepancy = \frac{|P_{reported} - P_{corrected}|}{P_{corrected}} \times 100\%$$

Where:

$TAE_{reported}$	=	The reported total annual emissions value.
$TAE_{corrected}$	=	The total annual emissions value, corrected for only the individual discrepancy in question.
$P_{reported}$	=	The reported production value.
$P_{corrected}$	=	The total production value, corrected for only the individual discrepancy in question.

2. All discrepancies are then aggregated on a magnitude basis:

$$Total \ Discrepancy = \sum |Each \ Discrepancy|$$

Example:

Three discrepancies are identified in a facility's compliance assertion:

1) 1% overstatement of total annual emissions due to a discrepancy in stationary fuel combustion emissions;
2) 2% understatement of total annual emissions due to a discrepancy of venting emissions; and
3) 3% overstatement of production due to a discrepancy of one production item.

Total Discrepancy = 1% + 2% + 3% = **6%**

In this example, the compliance assertion contains a **material** discrepancy.

Qualitative materiality refers to errors or mistakes that are non-numerical in nature or are difficult to quantify, and may include inconsistent methods or facility boundaries, misleading presentation of circumstances, poor data handling or record keeping, and lack of transparency. These errors can erode a third party verifier's ability to reach a necessary level of comfort with the compliance assertion and may result in a qualified or adverse assurance statement. Determining whether a material qualitative discrepancy has occurred is at the professional judgment of the third party verifier.

Alberta Environment and Sustainable Resource Development also considers materiality on an aggregate basis across the program. Small errors on a large emission source may be below a quantitative material threshold for a facility, but may result in a large financial cost relative to total program compliance costs. As such, all identified immaterial errors will be assessed to understand both facility materiality and program impact, and corrections will be determined accordingly.

Where facilities have deviated from published guidance, the third party verifier should check facility records to confirm that the facility has received approval in writing from Alberta Environment and Sustainable Resource Development, and should disclose any deviations in the verification report. If the facility has not received written approval, such deviations must be disclosed as discrepancies in the verification report, and should be quantified where possible

8.1.9 Level of Assurance

Alberta Environment and Sustainable Resource Development requires all baseline applications be verified to a **limited** level of assurance. This requires the verifier to obtain and check information through enquiry, analytical procedures, and discussion. Greenhouse gas verification completed to a limited level of assurance is more stringent than financial verification at a negative level of assurance, but is not sufficient to reach a positive conclusion regarding the compliance assertion.

Alberta Environment and Sustainable Resource Development will be adopting **reasonable assurance** for third party verification of baseline applications submitted in 2013 or beyond.

8.2 Verification Process

8.2.1 Engaging a Third Party Verifier

Each regulated facility is responsible for completing a baseline application and engaging a third party verifier to conduct verification of the baseline application assertion. Facilities must ensure that the third party verifier engaged to complete the verification meets the qualification requirements identified in Section 8.1.2 above and the independence requirements described in Section 8.1.4 above.

Once a third party verifier has been selected, the facility and the verifier should work together to determine an appropriate timeframe and schedule for the verification. This will include identifying key contacts for the facility, setting dates for site visits, and estimating a completion date for the verification. This allows both parties to set up an appropriate verification schedule to complete the verification as efficiently as possible.

8.2.2 Verification Plan and Sampling Plan

Third party verifiers should design a verification plan and a sampling plan to support a limited level of assurance for each baseline application review.

The **verification plan** documents the terms of the engagement and the planned verification procedures. The final verification activities are determined based on preliminary testing and risk identification. It is expected that the verification plan, in part or full, will be shared with the facility prior to the site visit in order to assist in preparation for both the site visit and document requests. This is particularly important when facilities need to make arrangements for appropriate staff to be present to support the review.

The verification plan should:

1. State the objectives of the verification.
2. State the level of assurance to be provided in the verification.
3. Assess the potential risks in the data management system by
   a. Assessing the inherent, control, and detection risk associated with greenhouse gas data and data management system to determine areas for further investigation.
   b. Performing analytical testing on the draft baseline assertion to determine areas for further investigation.
4. Assess the potential magnitude of any errors, omissions and misreporting by conducting a magnitude and sensitivity analysis on the reported data to determine parameters that significantly effect the baseline assertion.
5. Set an initial quantitative materiality level for any errors, omissions or misreporting.
6. Show the connections between the verification objectives, risks, magnitude of errors, anomalies, materiality, and procedures, and take into account the greenhouse gas data management systems as this determines the control risk for the next verification process. For example, one objective should be to determine whether the greenhouse gas emissions inventory is complete. The verification procedures for this objective could include:
   - A site visit to inspect and visually confirm the greenhouse gas inventory.
   - Enquiring how the client ensured completeness of the greenhouse gas inventory.

The **sampling plan** is a supporting document that is finalized once the verifiers have done an initial assessment of the robustness of the facility's greenhouse gas emissions data and emission management systems. The sampling plan typically identifies the sampling areas and sample sizes required to achieve a level of comfort with the reported data to support a limited level assurance review.

Third party verifiers are encouraged to use a risk-based approach to develop the sampling plan. More emphasis should be placed on sources with a higher likelihood for error and/or a greater ability to materially affect the compliance submission. Where errors or weaknesses are determined, the verifier may request additional supporting information to understand the error and its overall impact on the submission.

A summary of the final verification plan and sampling plan, including any deviations or changes that were made during the verification, must be included in or appended to the final verification report submitted to Alberta Environment and Sustainable Resource Development.

8.2.3 Site Visits

Site visits are required as part of the verification process. Site visits are used to confirm information contained in baseline application submissions, including the completeness and accuracy of emissions sources, products, measurement/estimation methods, data tracking systems, and boundary conditions.

In some circumstances, a site visit may be determined not to be feasible (e.g. for a remote cogeneration facility) or not necessary. A site visit should only be considered unnecessary in cases where a previous site visit from the same third party verifier was conducted within the previous July 1 – March 31 period. Whenever a site visit is omitted, the third party verifier should confirm that this is acceptable with Alberta Environment and Sustainable Resource Development prior to completing the verification and must provide clear and adequate justification regarding why the site visit was not conducted and what proxy data will be used as a substitute for the site visit.

8.2.4 Access to Information and Supporting Materials

Facilities must provide sufficient information to allow third party verifiers to evaluate completeness of the baseline application and render an assurance statement. Documents and information required to complete the verification will be facility specific and may include, but are not limited to:

- The baseline emissions intensity application containing the assertion to be verified and supporting documents;
- A description of the site processes;
- Assessment of boundary conditions;
- A simplified process flow diagram;
- Data flow sheets;
- An inventory of greenhouse gas sources;
- A brief description of the greenhouse gas data management system and quantification protocol used to calculate the greenhouse gas emissions;
- Sample calculations, including justification for negligible emission sources;
- Key supporting documents used to compile the baseline application; and
- Access to the facility to conduct a site visit.

Facilities can assist the verification process by having all relevant documents and records collated and available for the third party verifier prior to commencement of the verification. Facilities should also ensure that appropriate staff members are available to answer questions and provide information throughout the entire process.

It is important that key personnel are made available during the site visit, as this greatly improves the verifier’s ability to check data in a timely and efficient manner. Facilities should be prepared for the verifier to trace data and methodologies back to the raw data sources.

8.2.5 Closing meeting

The verification process typically concludes with a close-out meeting between the facility and the third party verifier to review the verification findings and attempt to resolve outstanding issues prior to submitting the baseline application. Third party verifiers are encouraged to provide a copy of the draft report to the facility in advance of the close-out meeting.

8.2.6 Verification Report

The verification report is a summary and discussion of the third party verifier's verification procedures and results. This report is submitted to Alberta Environment and Sustainable Resource Development as part of the facility's baseline application package. It should be sufficiently complete to provide Alberta Environment and Sustainable Resource Development assurance that the values reported in the baseline application are accurate and correct based on the information available.

The verification report must contain the following:

- The verification objective;
- The criteria against which the compliance assertion and supporting evidence was evaluated;
- A summary of the final verification plan;
- A summary of the final sampling plan;
- A complete verification schedule;
- The names, roles, and qualifications of verification team members and the peer reviewer;
- A risk assessment;
- All findings identifying any material and immaterial discrepancies found; and
- A limited level assurance statement for the baseline application.

Table 8 contains a sample table of contents for a verification report that meets the requirements identified above.

Section	Content
1. Verification Summary	Summary table containing: Facility identification information Facility contact information Verification objective Verification summary Audit team members Report and audit dates
2. Introduction	Provide an introduction to the facility and the verification. This should include a description of the facility.
3. Objective	Discuss the objective of the verification
4. Scope	Discuss the scope of the verification
5. Verification	List the verification criteria used and any relevant, supporting

Criteria	documentation used
6. Final Verification Plan and Sampling Plan	Provide a detailed discussion of the final verification plan including: • Methodologies • Key emissions sources • Final sampling plan • Other relevant information
7. Verification Schedule	Provide a list of verification activities and dates
8. Verification Procedures	Identify steps taken during the verification including: • Methodologies used to assess/verify emissions data • Comparison with approved baseline emissions intensity • Details of site visit • Other relevant information
9. Verification Findings	Discuss findings and results: • Material and immaterial discrepancies identified • Data management system and controls • Emissions sources • Production • Process flow diagram for the facility • Facility boundary compared with the facility definition under the *Regulation* • Statement of findings
10. Statement of Verification	This must be the Statement of Verification from the baseline application form
11. Verification Team	Clearly identify all team members (including the peer reviewer), and their respective duties.
12. Appendix	Any relevant documentation such as methodologies, and calculations that provide clarity and assist Alberta Environment and Sustainable Resource Development in assessing the completeness of the review.

Table 8**:** Third party verification report format**.**

Working papers do not need to be included in the verification report, but should be retained by the verifier for at least five years. If Alberta Environment and Sustainable Resource Development requires access to the verifier's working papers, Alberta Environment and Sustainable Resource Development will contact the facility to obtain access.

8.2.7 Statement of Verification

There are three verification statement types that can be issued for a limited level of assurance verification:

1. A limited level assurance statement;
2. A qualified limited level assurance statement; and
3. An adverse assurance statement.

A **limited level assurance statement** is issued by the third party verifier if the verifier is satisfied that they have undertaken sufficient procedures and there has been sufficient and appropriate evidence supplied to determine that nothing has come to their attention that causes them to believe that the assertion provided in the baseline application is not fairly stated in accordance with the appropriate criteria. This report may be issued despite outstanding, unresolved immaterial discrepancies.

The following is an example of a limited level assurance statement:

> "Based on our work, nothing has come to our attention that causes us to believe that the assertion provided in the 20XX baseline application for the YYYY facility is not, in all material respects, presented fairly and in accordance with the relevant criteria."

A **qualified assurance statement** is issued if the verifier is unable to form an opinion on certain aspects of the baseline application due to circumstances beyond the control of the third party verifier or facility personnel. Examples include the disposal of records in a manner compliant with regulations and the destruction of records in a natural disaster. Limitations on the scope of the assurance should be clear in the statement of verification and the reasons for the limitation should be disclosed in the verification report. Further guidance is provided in ISO 14064-3, Annex A.2.9.2.

The following is an example of a qualified assurance statement:

> "Based on our work, there was not sufficient and appropriate evidence to support a conclusion regarding the assertion provided in the 20XX baseline application for the YYYY facility. Readers are cautioned that the assertion for this period may not be appropriate for their purposes. Therefore, we are issuing a qualified statement of assurance that based on our work, nothing has come to our attention that causes us to believe that the compliance assertion provided in the 20XX baseline application for the YYYY facility is not, in all material respects, presented fairly and in accordance with the relevant criteria."

An **adverse assurance statement** is issued in rare cases where there are outstanding, unresolved material discrepancies. Adverse assurance statements may be issued, for example, if the verifier cannot access sufficient information to assess the validity of the baseline application.

The following is an example of an adverse assurance statement:

> "Based on our work, the 20XX baseline application for the YYYY facility does not contain all the disclosures required by Alberta Environment and Sustainable Resource Development. Readers are cautioned that these statements may not be appropriate for their purposes."

For regulated facilities to be in compliance with the *Regulation*, baseline application submissions must be accompanied by a limited level of assurance statement. In cases where a limited level of assurance statement cannot be provided by the submission deadline, facilities **must** inform Alberta Environment and Sustainable Resource Development as soon as possible to discuss the most appropriate path forward.

8.2.7.1 Content of the Statement of Verification

The statement of verification (form SoV in the baseline application) must be completed, signed and submitted to Alberta Environment and Sustainable Resource Development and is the final assurance statement for the third party verification. The statement of verification must:

- Identify the associated baseline application for which verification was provided, including the applicable time period;
- Include the compliance assertion that was verified;
- Describe the responsibilities of the third party verifier and the reporting company;
- Identify the verification standard used to conduct the verification;
- Provide a conclusion that conveys the level of assurance being provided and/or any reservation the verifier may have; and
- Include the signature of the designated signing authority.

8.3 Verification for Resubmissions

In situations where facilities re-submit previously submitted baseline applications with corrections, updates, or changes, verification will be required on either the changes only or the entire report, depending on the nature and the extent of the changes.

Minor changes and clarifications will typically require a signed letter from the verifier stating what was changed, the rational for the change, and that no other changes were made to the baseline application. When changes are significant or affect multiple portions of the baseline application, a complete verification may be required. In some cases Alberta Environment and Sustainable Resource Development may require that a new third party verifier be used.

8.4 Subsequent Events

Third party verifiers are not required to actively monitor the validity of their reports after issuance; however, where it is brought to the attention of the third party verifier that a previous statement is no longer accurate, they must notify the facility. The facility must notify Alberta Environment and Sustainable Resource Development to discuss further follow-up actions that may be required.

9.0 Alberta Environment and water Audit

Each year, Alberta Environment and Sustainable Resource Development commissions third party teams to conduct re-verifications (audits) of approximately 10 per cent of the annually submitted baseline applications. These audits are conducted on behalf of Alberta Environment and Sustainable Resource Development, and the results of which are reported directly to Alberta Environment and Sustainable Resource Development. The audits are conducted to further check the accuracy of reported information and to help identify anomalies. Information from the audits is used to ensure transparency in the specified gas emitters program and to support annual program reviews.

9.1 Audit Process

Alberta Environment and Sustainable Resource Development audits are similar to third party verifications described in Section 8.0 above, but are conducted on behalf of Alberta Environment and Sustainable Resource Development, are independent of the third party verification and undergo a different process, which is illustrated in Figure 66 below.

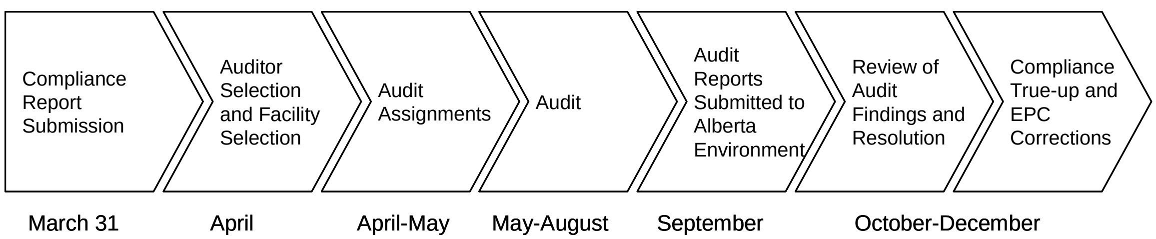

Figure 6: Alberta Environment and Sustainable Resource Development's compliance report audit process highlights.

Alberta Environment and Sustainable Resource Development issues a request for proposal to solicit bids from qualified audit teams. Auditors are hired based on whether they meet the requirements for a third party auditor (as described in section 18 of the *Regulation*), their audit experience, and their sector specific expertise. Auditors hired by Alberta Environment and Sustainable Resource Development must meet the same independence requirements as third party verifiers.

After audit teams have been selected, Alberta Environment and Sustainable Resource Development conducts an internal review process, based on the criteria described in Section 9.2 below, to determine which reports will be audited. Auditors are then assigned to the selected baseline applications based on budget, scheduling, and auditor expertise. An audit team will not be assigned to complete a facility audit if there is an actual or perceived conflict of interest, unless sufficient action can be taken to ensure independence.

Once auditors have been assigned, Alberta Environment and Sustainable Resource Development issues written notice to the facilities indicating they have been selected for a supplemental audit. Auditors work directly with the facilities to set up an appropriate audit schedule and to request supplemental information required to complete the audit.

Auditors are required to perform a site visit. Details of the site visit and audit are included in the verification plan, which is shared with the facility before the site visit.

Auditors may schedule a close-out meeting with the facility to discuss key findings; however, the audit report is submitted directly to Alberta Environment and Sustainable Resource Development. Alberta Environment and Sustainable Resource Development reviews the final audit findings and concludes the audit by meeting with the facility to determine what, if any, follow-up action is needed. Alberta Environment and Sustainable Resource Development works with individual facilities to address any outstanding issues. Once all outstanding concerns have been addressed, facilities receive written notice confirming completion of the audit. If corrective action is required, Alberta Environment and Sustainable Resource Development will work with the facilities to determine an appropriate path forward.

9.2 Facility Selection

Alberta Environment and Sustainable Resource Development uses a risk-based approach to select facilities for auditing, the criteria used to select facilities for audit include:

- Coverage across facilities and sectors;
- Facility size (annual emissions and production);
- Product and process complexity;
- The number of previous audits a facility has undergone;
- The results from previous audits;
- Familiarity of sectors/facilities within Alberta Environment and Sustainable Resource Development's Climate Change Secretariat;
- Issues related to the applicability of baseline emissions intensities (e.g. if Alberta Environment and Sustainable Resource Development is concerned that the BEI may not represent ongoing facility operations).
- Anomalies or issues encountered during the desktop review; and
- The number and extent of previous restatements that have been made.

Note: *Some facilities may be audited more than once or be audited several times in succession.*

9.3 Materiality for Alberta Environment and Sustainable Resource Development Audits

Alberta Environment and Sustainable Resource Development uses the same materiality threshold for audits as for third party verification (see Section 8.1.8). Auditors assess both quantitative and qualitative errors associated with a compliance report to reach a limited level of assurance regarding the compliance assertion. Auditors are required to identify all material and immaterial errors discovered during the audit in the final audit report.

9.4 Audit Standards

Auditors must use one of the following three verification standards, consistent with third party verification requirements:

- ISO 14064-3 (Greenhouse Gases – Part 3): Specification with guidance for the validation and verification of greenhouse gas assertions
- Standards for Assurance Engagements, Canadian Institute of Chartered Accountants (CICA) Handbook – Assurance Section 5025
- International Standard on Assurance Engagements (ISAE) 3000 – Assurance Engagements Other Than Audits or Reviews of Historical Financial Information

Auditors will select the methodology appropriate to their audit. The methodology used by the auditors may be different from the methodology used by the third party verifier; however, the original compliance submission and third party verification should be sufficiently robust such that an independent party can reach same conclusion as the original verification regardless of the verification standard.

9.5 Level of Assurance

Alberta Environment and Sustainable Resource Development requires all audits be performed to at least a limited level of assurance, consistent with the requirements for third party verification; however, Alberta Environment and Sustainable Resource Development may request some audits be performed at a reasonable level of assurance.

9.6 Audit Report

Auditors produce an audit report for each audited facility. This report meets the same requirements identified for verification reports in Section 8.2.6**Error! Reference source not found.**, and is submitted directly to Alberta Environment and Sustainable Resource Development. Alberta Environment and Sustainable Resource Development will share a copy of the audit report with the facility after it has been finalized.

9.7 Continuous Improvement

Alberta Environment and Sustainable Resource Development is committed to continuous improvement. Alberta Environment and Sustainable Resource Development will undertake an annual review of the specified gas emitters program, particularly during the initial years of the program. Results from the audit process will be used to provide input into what areas are working and what areas need adjustments. As such, Alberta Environment and Sustainable Resource Development has asked its auditors to identify any issues encountered during the audit, which serves as part of an independent review of the specified gas emitters program.

9.8 Confidentiality Considerations

Auditors are commissioned by Alberta Environment and Sustainable Resource Development. Acting on behalf of Alberta Environment and Sustainable Resource Development, auditors are bound by the Government of Alberta confidentiality requirements, and must comply with all appropriate confidentiality regulations. Further, the contracts between Alberta Environment and Sustainable Resource Development and the audit teams explicitly reference confidentiality requirements under the *Freedom of Information and Protection of Privacy Act*, which mandates how information submitted to the Alberta Environment and Sustainable Resource Development is to be handled for confidentiality purposes.

Information collected through the audit process is subject to section 16 of the *Specified Gas Emitters Regulation*, and may be requested to be kept confidential by submitting a written request to the Director, which identifies confidential material and provides justification for the request. More information about confidentiality can be found in Section 7.0.

Glossary of Terms

Baseline Assertion emissions, production and baseline emissions intensity submitted as part of the baseline application.

Baseline Emissions Intensity (BEI) for established facilities is the average of that facility's annual emissions intensity for 2003, 2004 and 2005. For new facilities, the BEI is based on the third, fourth and fifth year of commercial operation.

Biomass refers to material derived from living or recently dead organisms. Examples include, but are not limited to: wood and wood products, charcoal, agricultural residue, landfill gas and bio-alcohols. A more complete list is available in Section 5.2.9 of this document.

Biomass emissions are direct emissions resulting from the decomposition and/or combustion of biomass from plant materials and animal waste

Certifying Official is the person designated by the facility with signing authority for that facility.

Climate Change and Emissions Management Act is the enabling legislation passed in 2002 allowing Alberta Environment and Sustainable Resource Development to manage greenhouse gas emissions in the province.

Climate Change and Emissions Management Fund is the fund set up under the Climate Change and Emissions Management Act that will be used to support research, development and deployment of transformative technologies to reduce greenhouse gas emissions in Alberta.

CO_2e is the 100-year global warming potential of a unit of greenhouse gas (e.g. methane) in units of carbon dioxide (reference gas).

Direct emissions means the release of greenhouse gases expressed as tonnes CO_2e from all sources located at a facility.

Director is Alberta Environment and Sustainable Resource Development's representative appointed under the *Specified Gas Emitters Regulation* and who is charged with implementing the *Regulation*.

Emission offset is a reduction in one or more specified gases (regulated greenhouse gas emissions) occurring at sites not covered by the *Specified Gas Emitters Regulation.* Additional information on Offsets is available at: http://environment.alberta.ca/3313.html.

Emission Performance Credits (EPCs) are generated when a facility reduces its Emissions Intensity below its Net Emissions Intensity Limit. EPCs are awarded on a tonne CO_2e reduction basis

Established facility is a facility that completed its first year of commercial operation on or before January 1, 2000, or that has completed eight consecutive years of commercial operation.

Facility is any plant, structure or thing that sits on one or more contiguous or adjacent sites that are operated and function in an integrated fashion and includes all buildings, equipment, structures, machinery and vehicles that are an integral part of the activity.

Flaring emissions are direct emissions from the controlled combustion of a gas or liquid stream produced on site for purposes other than producing energy. This includes but is not limited to the incineration of waste petroleum and other hazardous materials, safety flares, and test wells.

Formation CO_2 emissions are direct, gaseous emissions of carbon dioxide recovered or recoverable at a well from an underground reservoir including, but not limited to, CO_2 emissions vented from gas sweetening and formation gas.

Fund Payment is a compliance payment made into the Climate Change and Emissions Management Fund.

Global Warming Potential (GWP) measures a greenhouse gas's relative warming effect on the earth's atmosphere compared with carbon dioxide and is expressed as a 100-year average. Alberta accepts the Intergovernmental Panel on Climate Change's warming potentials for the gases regulated under the *Specified Gas Emitters Regulation*.

Greenhouse gases are the atmospheric gases responsible for the greenhouse gas effects. The most common greenhouse gases are carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O). Less prevalent, but very powerful, greenhouse gases include hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulphur hexafluoride (SF_6).

HFC Species are hydroflurocarbon gases and include: CHF_3, CH_2F_2, CH_3F, $C_5H_2F_{10}$ (structure: $CF_3CHFCHFCF_2CF_3$), C_2HF_5, $C_2H_2F_4$ (structure: CHF_2CHF_2), $C_2H_2F_4$ (structure: CH_2FCF_3), $C_2H_3F_3$ (structure: CHF_2CH_2F), $C_2H_3F_3$ (structure: CF_3CH_3), $C_2H_4F_2$ (structure: CH_3CHF_2), C_3HF_7 (structure: CF_3CHFCF_3), $C_3H_2F_6$ (structure: $CF_3CH_2CF_3$) and $C_3H_3F_5$ (structure: $CH_2FCF_2CHF_2$). These gases are regulated under the *Specified Gas Emitters Regulation*.

Industrial process emissions are direct emissions from sources directly associated with production that involve chemical or physical reactions, other than combustion, and where the primary purpose of the process is not energy production.

Industrial product use emissions are all direct emissions from the use of HFCs, PFCs or SF_6 associated with production that does not meet the definition of Industrial Process Emissions. Examples include SF_6 and HFC use as a cover gas and SF_6 in on-site electrical equipment.

Materiality refers to a measure of the magnitude of an error omission or misrepresentation that would affect the compliance assertion stated in the baseline emissions intensity application or compliance statement.

Net Emissions Intensity (NEI) is the facility's Total Annual Emissions minus true-up options used (Offsets, EPCs, or Fund Contributions) divided by the facility's total annual production expressed in appropriate units.

Net Emissions Intensity Limit (NEIL) is the facility's maximum net emissions intensity permitted under section 4 of the *Specified Gas Emitters Regulation.* This limit is set at 88 per cent of the baseline emissions intensity for existing facilities. New facilities are phased in at a rate of 2 per cent per year starting in their fourth year of commercial operation.

New facility is a facility that completed its first year of commercial operation on or after December 31, 2000 and has completed less than eight years of commercial operation.

On-site transportation emissions are direct emissions resulting from fuel combustion in machinery used for the on-site transportation of products and material including raw, intermediate and end products.

Other/Fugitive emissions are direct emissions that do not fall under the other emissions categories and includes, without limitation, intentional or unintentional releases of gases arising from the production, processing, transmission, storage and use of solid, liquid or gaseous fuels.

Person Responsible is the person legally responsible for the operations of the facility. This person is the approval or registration holder for a facility regulated under the *Environmental Protection and Enhancement Act* or the legal owner for facilities not subject to EPEA approval.

PFC species are perflurocarbon gases and include: CF_4, C_2F_6, C_3F_8, C_4F_{10}, c-C_4F_8, C_5F_{12}, and C_6F_{14}. These gases are subject to the *Specified Gas Emitters Regulation*.

Production is the total quantity of end product(s) produced by a facility. If a facility does not have an end product, the Director under the *Specified Gas Emitters Regulation* may specify an input, throughput or other thing as a production metric.

Regulation means the *Specified Gas Emitters Regulation*.

Reporter is the person designated by the facility responsible for completing the facility's Baseline Emissions Intensity Application form.

Specified gases are the six greenhouse gas species—carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), PFCs, HFCs, and sulphur hexafluoride (SF_6)—regulated under the *Climate Change and Emissions Management Act* and the *Specified Gas Emitters Regulation*.

Stationary fuel combustion emissions are direct emissions from the combustion of fossil or biomass fuel for the purpose of producing energy excluding CO_2 emissions from the combustion of biomass.

Total Annual Emissions (TAE) are the total direct emissions not including industrial process emissions, CO_2 emissions from combustion of biomass and CO_2 emissions from decomposition of biomass waste emitted by a facility in a calendar year.

Total Direct Emissions (TDE) is the release of all specified gases expressed in tonnes CO_2e from all sources located at a facility.

Third Party Verifier is a professional engineer or chartered accountant qualified to conduct an independent, third party review of the facility's baseline application before it is submitted to Alberta Environment and Sustainable Resource Development.

Unit of production is an appropriate common production metric for all end products of a facility consistent with the industry accepted norms for the sector to which the facility belongs.

Venting emissions are direct emissions from the intentional release to the atmosphere of waste gas or liquid streams.

Waste and wastewater emissions means direct emissions from disposal or treatment of waste or wastewater, but does not include CO_2 emissions from decomposition of biomass waste.

Year is calendar year.

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