

**Comments to 3rd Posting of Quantification Methodologies**

This table summarizes the questions and comments received by April 25, 2018 for the 3rd posting of the quantification methodologies.

#	Page #	Line	Clause/ Section	Intro Section	Table	Equation	Comment/Question	Responses
1			1.3.2 (3)				What does internal combustion engine encompass? (turbines and recipis or just recipis)	Yes, it should include both turbines and reciprocating engines. Table 1-2 is modified to indicate that turbines are considered to be internal combustion engines.
2			17.2.1(a)				What does 'where potentially material' mean in the sentence "Facilities may determine fuel consumption on the basis of direct measurement, fuel purchase records, or sales invoices measuring any stock change where potentially material, ..."	Updated to reflect additional requirements to quantify liquid fuel usage based on volume of storage tank on site.
3			17.2.1(b)(iii)				What does "quantified" mean in the sentence "...total fuel can be measured or quantified..."? Does this include engineering calculations or mass balance?	Facilities must use the methodologies that are prescribed under the tier classification that applies to their facility. Acceptable methodologies under the various tiers may include actual measurements and/or other methods to quantify emissions such as engineering estimates and/or mass balances.
4			C.10				Our methodology up to this point was to measure carbon going into the process in coal and carbon coming out of the process in the ash. We then did a true mass balance calculation assuming that all carbon that did not come out of the process as ash was 100% oxidized. Both <Redacted> and <Redacted> had commented on this in the previous draft and the response comments by the ACCO stated that the policy was to assume 100% oxidation carbon to carbon dioxide but that you would continue to evaluate whether subtraction of un-oxidized ash should be accepted. We understand that the above clause was put into place to address some old methodologies that assumed 98% oxidation from flares and incinerators, however, we would like to also point out that the IPCC Guidelines (volume 2, Chapter 2, Section 2.1) states the following: The default oxidation factor is assumed to be 1, unless better information is available.	ACCO is adapting an oxidation factor of 99.48% for coal combustion used for electricity generation. This value is derived from a study conducted by ECCC on oxidation factors for coal combustion.
5	11		Definitions- Negligible emission Definitions- Negligible emission sources				We recommend that the definition be amended as follows: "Negligible emissions sources" are sources that represent less than 1% of a facility's total direct CO2 equivalent emissions (CO2e) and are not to exceed a limit of 1,000 tonnes of CO2e." This is to avoid investments that do not improve the accuracy of the quantification of the facility's total CO2e emissions.	Definition of "negligible emissions sources" have been updated. ACCO is allowing facilities to use alternative methods to assess negligibility of these emissions as these emissions are considered to be low risk.
6	16		1.2.4 Tier 3 - CO2 emissions from variable fuels based on the measured fuel carbon content				The Standard for Completing GHG Compliance and Forecasting Reports specifies to follow Tier 3 procedure for Refining combustion sources, ref: table 2 (pg. 27 of 37). Since Tier 3 is specific to variable fuels, to avoid misinterpretations and confusion between QMD and the above Standard, a clarifying comment should be added under the Tier 3 section of QMD to direct readers to Tier 1 for non-variable fuels.  The current text in QMD reads as follows: "For FCC processes, the emissions are considered to be stationary fuel combustion; however, there are no quantification methodologies currently prescribed. Facilities performing these processes may develop their own quantification methodologies until such methodologies are provided in this chapter." Please clarify that for the FCC process sites can continue to follow their existing practices around sampling, measurement and data management (vs. Chapter 17) until such methodologies are available in the QMD. For example: Applying existing QMD procedures (in Ch-17) to backfill data concerning FCC (coke burn, flue gas composition, etc.) would not be an accurate approach.	Language updated to allow Tier 3 facilities to apply Tier 1 methodologies to calculate CO <sub>2</sub> from the combustion of non-variable fuels. Language added to allow facilities to use existing quantification methodologies for FCC processes.
7	21		Table 1-2 Default CH4 & N2O EFs for NG				Per ACCO's Summary of Stakeholder Questions and Comments to the Draft Quantification Methodologies (Postings 1 and 2) - comment #142, unit conversion calculations were performed based on US EPA AP-42. However, in the below example, following the same standard outputs yields slightly different result: NOx controlled/uncontrolled CH4 EF in table 1.4-2 of AP-42 is: 2.3 lb/mmcf or $(2.3/1020 * 1/1055 * 1/2.205) = 9.693E-07$ tonnes/GJ vs. $9.702E-07$ tonnes/GJ in table 1-2 of the quantification document [1020 in the above equation is a factor to convert lb/mmcf of NG to lb/mmbtu; from AP-42]. We recommend: To list all EFs in the same engineering units as available in the original source (AP-42)	Updated per comment.

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8	48		Section 13.12 Refining- Introduction and CCIR Schedule 2 Established Benchmarks for Products, Definitions, 1(1)(g)"refining" (p. 40-42)				<p>The current definition reads as follows: "refining" means any manufacturing or industrial process that occurs at a refinery at which crude oil or bitumen is processed or refined into a transportation fuel."</p> <p>We recommend:</p> <ul style="list-style-type: none"> <li>• To add to the refining definition a minimum percentage of liquid petroleum finished product manufactured at a facility. Alberta should consider aligning with ECCC's definition, ref: OBPS Petroleum Refining Sector Working group meeting Mar 1, 2018 - slide 9-10.</li> <li>• When the upgrading benchmark will be added to Schedule 2 (CCIR Established Benchmarks for Products), the upgrading definition should include a maximum percentage of finished liquid petroleum product produced at a facility.</li> </ul> <p>The above recommendation is to provide a quantifiable distinction between upgraders and refiners and avoid overlapping definitions.</p>	ACCO will address policy comments related to the SGRR and CCIR separately.
9	61		17.0 Measurement, Sampling, Analysis and Data Management requirements				In ACCO's Summary of Stakeholder Questions and Comments to the Draft Quantification Methodologies (Postings 1 and 2) - comment # 316, the response is "Intend to require all chapters (such as flaring and venting) to follow methodologies prescribed in Chapter 17 and Appendix C..." Please confirm that the requirement to follow Ch-17 will become effective only after the publication of the prescribed methodologies associated to venting, flaring etc.	Chapter 17 is mandatory for 2018. Additional requirements for flaring and venting will be added to Chapter 17 when these chapters become available.
10			CWB Factor POX Unit				The Solomon methodology includes a factor for Gasifiers (or POX) units of 7.1 CWB per 1000 SCFD while the Quantification Methodology caps all H2 production sources at the SMR factor of 5.7. <Redacted> configuration includes a gasification unit that converts a high carbon by-product (cracked vacuum residue) into useful products including H2 for the refinery and pure liquid CO2 for Enhanced Oil Recovery purposes. With the recent modifications to the Quantification Methodology, this is now essentially the only exception to the Solomon CWB method in the refining sector OBA and hence <Redacted> is uniquely disadvantaged versus others in the sector as we will have the only gasification unit once operating. <Redacted> suggests removing the exception found in Section 13.12.3 Process CWB of the Quantification Methodologies (v4).	ACCO will address policy comments related to the SGRR and CCIR separately.
11			H2 Methodology Biases				In addition to the specific factor applied to the gasifier, the combination of the low allowance factor (high stringency) for the refining sector combined with the CWB factor may result in an un-level playing field in the H2 supply choices amongst the various refiners. As the stringency targets for the Hydrogen or Upgrader industries are not transparent at this point (even at a common CWB factor per unit of H2 production), the allowance for an inside the fence refinery unit could be much lower than for an over-the-fence supply choice. The total exclusion of the indirect emissions for over the fence H2 supply is a contributing factor to this issue unless a common stringency is applied.	ACCO will address policy comments related to the SGRR and CCIR separately.
12	39-41		8.7.3 Tier 1 Method 2: N2O emission factor method for direct stack test; 8.7.4 Tier 2 - CEMS Method				'Table 2: Tier assignment for regulated facilities' of the 'Standard for Completing Greenhouse Gas Compliance and Forecasting Reports' specifies N2O IP emissions must be reported using Tier 2 methodology. The only permitted Tier 2 quantification method for N2O from nitric acid production is the CEMS method (Section 8.7.4). Section 8.7.3 outlines a Tier 1 methodology for developing a site specific emission factor using an annual stack test and associated measured production. Why is the quantification methodology outlined in Section 8.7.3 not considered at least Tier 2 when a similar site specific stack test based emission factor methodology is deemed Tier 4 (8.4.5 Measured CO2 emission factor method for CO2 from use of carbonates), and CEMS monitoring in other sections is considered Tier 4 (Sections 1.2.5, 1.3.3)? More generally, what is the specific criteria for assigning Tiers?	The assignment of tiers reflect the requirements of the respective regulations (CCIR and SGRR). Under SGRR, the methodologies are at minimum aligned with ECCC's requirements (lowest tier); while the methodologies prescribed for large final emitters under the CCIR tend to be more stringent (higher tiers). ACCO recommends that the facility submit a deviation request for requirements that the facility cannot currently meet. ACCO will continue to evaluate and consider future modifications to the prescribed quantification methodologies.
13	33		8.4.4 Tier 3 - Carbonate mass balance method				Section 8.4.4 Tier 3 - Carbonate Mass Balance method for CO2 from use of carbonates requires carbonate in input material reacted and carbonate in output material produced to be measured. If the process is known to have minimal carbonate in the output material, the carbonate fraction reacted would effectively be 1.0 and there would be no added benefit or improved accuracy to analyzing the output material as all carbonate is emitted as CO2. This is the Tier 1 - Carbonate consumption method. Wouldn't Tier 3 requirements be met in this case without the added output material analysis if the process reaction fraction is effectively 1.0?	We currently do not have adequate data to suggest that the carbon content in the output material is insignificant. If the facility is able to demonstrate based on facility data that the oxidation factor is 1, the facility may submit a deviation request with this information to ACCO for consideration.

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14	60		CO <sub>2</sub> Emission Factors for Biomass				<p>Environment and Climate Change Canada (ECCC) prepares national GHG inventories for the country, and therefore GHG emission factors from this source are frequently referred to as ECCC emission factors. Emission factors for biomass combustion for Canada’s GHG reporting program can be found in Book 2 of Canada’s National Inventory Report[1]. It should be noted that wood fuel/wood waste and spent pulping liquor emission factors are normalized to 50% moisture content and are reported on a fuel basis (dry solids and moisture). The wood fuel/wood waste emission factors on an energy basis are taken from EPA AP-42[2] and converted to a mass basis by assuming a higher heating value of 10.47 MJ/kg (fuel), i.e. 20.94 MJ/kg dry solids. The higher heating value for wood fuel/wood waste was “developed from an internal review of available moisture content and heating value data”. The spent liquor CO<sub>2</sub> emission factor on an energy basis is taken from the NCASI GHG Calculation Tool[3] and converted to a mass basis by assuming, incorrectly, the “same HHV vs. moisture content relationship used to convert wood waste.” The CH<sub>4</sub> and N<sub>2</sub>O emission factors for spent pulping liquor are taken from 2006 IPCC Guidelines. Biomass emission factors used in Canada’s GHG reporting program are given in Table 1.</p> <div style="text-align: center;"> <p><b>Table 1. Reproduction of Table A6-32, pg. 250. Emission Factors for Canada’s GHG Reporting Program</b></p> <table border="1"> <thead> <tr> <th rowspan="2">Source</th> <th colspan="3">Emission Factor (g/kg fuel)</th> </tr> <tr> <th>CO<sub>2</sub></th> <th>CH<sub>4</sub></th> <th>N<sub>2</sub>O</th> </tr> </thead> <tbody> <tr> <td>Wood Fuel/Wood Waste</td> <td>840</td> <td>0.09</td> <td>0.06</td> </tr> <tr> <td>Spent Pulping Liquor</td> <td>891</td> <td>0.02</td> <td>0.02</td> </tr> </tbody> </table> </div> <p>It is, however, incorrect to assume that spent pulping liquor has the same HHV vs. moisture content relationship as wood fuel/wood waste. There is extensive literature on the heating values for biomass (Chandrasekaran et al. 2012; Parr and Davidson 1922; White 1987; Baker 1983; and McBurney 1993 for example). Heating values are strongly positively correlated to the carbon content of the fuel. Hardwood species usually have a carbon content in the range of 47-50%, while softwood species have a carbon content in the range of 50-53% (Baker 1983). Because of the higher carbon content of softwood species, heating values of softwood are typically higher than hardwoods; a typical HHV for softwoods is 9,000 BTU/lb or 20.9 GJ/dry tonne and a typical HHV for hardwoods is 8,600 BTU/lb or 20.0 GJ/dry tonne (Baker 1983). Heating values vary (±5% from these typical values) depending upon specific wood species (Baker 1983). The carbon content of spent liquor is lower than solid wood residuals because of the contribution of inorganic cooking chemicals (primarily sodium and sulfur) to the liquor. A typical carbon content of North American softwood spent liquor solids is 35% and may range from 32-37.5% and a typical carbon content of North American hardwood spent liquor solids is 34% and may range from 31-36.5% (Gullichsen, J., Paulapuro, H. 1999). Because of the lower carbon contents of spent liquor solids compared to solid biomass, a typical North American softwood spent liquor solids HHV is 6,100 BTU/lb (14.2 GJ/dry tonne) and ranges from 5700-6450 BTU/lb, and a typical North American hardwood spent liquor solids HHV is 5,975 BTU/lb (13.9 GJ/dry tonne) and ranges from 5500-6350 BTU/lb (Gullichsen, J., Paulapuro, H. 1999). The Canadian emission factors for spent liquor solids can be corrected by assuming an average heating value for spent liquor solids is the average of a typical North American softwood and hardwood kraft liquor, 14.0 GJ/dry tonne (average of 14.2 and 13.9 GJ/dry tonne), and applying the ratio of the average spent liquor solids heating value and the wood fuel/wood waste heating value used in Canada’s national inventory reporting (14.0 GJ/dry tonne / 20.94 GJ/dry tonne or 0.67) to the spent liquor emission factors. The corrected factors then become, Table 2.</p> <p>Table 2. Spent liquor emission factors for Canada’s GHG Reporting Program corrected for the erroneous assumption on spent liquor heating value</p> <div style="text-align: center;"> <p><b>Table 2. Spent liquor emission factors for Canada’s GHG Reporting Program corrected for the erroneous assumption on spent liquor heating value</b></p> <table border="1"> <thead> <tr> <th rowspan="2">Source</th> <th colspan="3">Emission Factor (g/kg fuel)</th> </tr> <tr> <th>CO<sub>2</sub></th> <th>CH<sub>4</sub></th> <th>N<sub>2</sub>O</th> </tr> </thead> <tbody> <tr> <td>Spent Pulping Liquor</td> <td>598</td> <td>0.013</td> <td>0.013</td> </tr> </tbody> </table> </div>	Source	Emission Factor (g/kg fuel)			CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O	Wood Fuel/Wood Waste	840	0.09	0.06	Spent Pulping Liquor	891	0.02	0.02	Source	Emission Factor (g/kg fuel)			CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O	Spent Pulping Liquor	598	0.013	0.013	<p>ACCO intends to align with ECCC on emission factors used for quantifying biomass combustion emissions and will consult with ECCC on a decision to update emissions factors related to spent pulping liquor. It is noted that Chapter 14 Quantification Methods for Carbon Dioxide from Combustion of Biomass is not mandatory for 2018 under CCIR.</p>
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15	23		CH <sub>4</sub> and N <sub>2</sub> O Emission Factors for Biomass				<p>It is, however, incorrect to assume that spent pulping liquor has the same HHV vs. moisture content relationship as wood fuel/wood waste. There is extensive literature on the heating values for biomass (Chandrasekaran et al. 2012; Parr and Davidson 1922; White 1987; Baker 1983; and McBurney 1993 for example). Heating values are strongly positively correlated to the carbon content of the fuel. Hardwood species usually have a carbon content in the range of 47-50%, while softwood species have a carbon content in the range of 50-53% (Baker 1983). Because of the higher carbon content of softwood species, heating values of softwood are typically higher than hardwoods; a typical HHV for softwoods is 9,000 BTU/lb or 20.9 GJ/dry tonne and a typical HHV for hardwoods is 8,600 BTU/lb or 20.0 GJ/dry tonne (Baker 1983). Heating values vary (±5% from these typical values) depending upon specific wood species (Baker 1983). The carbon content of spent liquor is lower than solid wood residuals because of the contribution of inorganic cooking chemicals (primarily sodium and sulfur) to the liquor. A typical carbon content of North American softwood spent liquor solids is 35% and may range from 32-37.5% and a typical carbon content of North American hardwood spent liquor solids is 34% and may range from 31-36.5% (Gullichsen, J., Paulapuro, H. 1999). Because of the lower carbon contents of spent liquor solids compared to solid biomass, a typical North American softwood spent liquor solids HHV is 6,100 BTU/lb (14.2 GJ/dry tonne) and ranges from 5700-6450 BTU/lb, and a typical North American hardwood spent liquor solids HHV is 5,975 BTU/lb (13.9 GJ/dry tonne) and ranges from 5500-6350 BTU/lb (Gullichsen, J., Paulapuro, H. 1999). The Canadian emission factors for spent liquor solids can be corrected by assuming an average heating value for spent liquor solids is the average of a typical North American softwood and hardwood kraft liquor, 14.0 GJ/dry tonne (average of 14.2 and 13.9 GJ/dry tonne), and applying the ratio of the average spent liquor solids heating value and the wood fuel/wood waste heating value used in Canada’s national inventory reporting (14.0 GJ/dry tonne / 20.94 GJ/dry tonne or 0.67) to the spent liquor emission factors. The corrected factors then become, Table 2.</p> <p>Table 2. Spent liquor emission factors for Canada’s GHG Reporting Program corrected for the erroneous assumption on spent liquor heating value</p> <div style="text-align: center;"> <p><b>Table 2. Spent liquor emission factors for Canada’s GHG Reporting Program corrected for the erroneous assumption on spent liquor heating value</b></p> <table border="1"> <thead> <tr> <th rowspan="2">Source</th> <th colspan="3">Emission Factor (g/kg fuel)</th> </tr> <tr> <th>CO<sub>2</sub></th> <th>CH<sub>4</sub></th> <th>N<sub>2</sub>O</th> </tr> </thead> <tbody> <tr> <td>Spent Pulping Liquor</td> <td>598</td> <td>0.013</td> <td>0.013</td> </tr> </tbody> </table> </div>	Source	Emission Factor (g/kg fuel)			CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O	Spent Pulping Liquor	598	0.013	0.013																
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16	29				Table 1-3		No emission factors are provided for landfill gas or biogas. How should CH <sub>4</sub> and N <sub>2</sub> O emissions from these fuels be calculated?	Methodologies related to the flaring of landfill gas or biogas are prescribed in Chapter 2 Flaring, which will be published at a later date for stakeholder comment. Methodologies related to the combustion of landfill gas or biogas for useful energy will be addressed at a later date in Chapter 1 Stationary Fuel Combustion or Chapter 6 Waste and Digestion. Facilities currently reporting these emissions may use facility specific methodologies. For facilities reporting under CCIR, these methodologies must be documented in the facility's Quantification Methodology Documents.
17	34		Section 14.4				Equation provided in this section essentially categorizes all CO <sub>2</sub> emissions from a fuel under Combustion of Biomass. For the case of biogas from a wastewater treatment plant, the biogas will be comprised of CO <sub>2</sub> (from decomposition of biomass) as well as CH <sub>4</sub> that is burned for energy and converted to CO <sub>2</sub> . The former CO <sub>2</sub> (from decomposition of biomass) would be categorized under Combustion of Biomass as opposed to Biomass Decomposition. Please clarify if this is the intent.	Yes, CO <sub>2</sub> from combustion of biogas is considered a biomass emission.
18	36					Equation 14-3e	EF is defined as measured emission factor for biomass solid fuel. What about gaseous fuels (eg. Using biogas in a cogeneration turbine to produce steam).	For gaseous biofuels, Equation 14-3a or 14-3b should be applied.
19	39				Table 14-1		Table does not include emission factors for landfill gas or biogas. Are these fuels required to be quantified under Tier 3?	Yes, landfill gas or biogas is not considered to be a non-variable fuel and therefore, requires specific fuel data to calculate CO <sub>2</sub> emissions.
20	40		Section 13.6				Is electricity produced and consumed on site not required to be reported? Section indicates "electricity means electricity that is exported from the facility".	Under CCIR, an allocation is provided only if the electricity is exported outside of the facility boundaries; however the facility is still required to report imported, exported, generated and used electricity for compliance reporting.
21	14	22					Gas oil and bio-diesel should be considered as non-variable in composition fuel	Gas oil or heavy industrial oil is not considered to be non-variable fuel. In Table 1-1, "Diesel in Alberta" represents fuels that are impacted by Alberta's Renewable Fuel Standard, where the emissions factors are adjusted to account for the required biofuel content. In addition, an additional line item has been added for "Biodiesel" for methane and nitrous oxide emission factors.
22	21				Table 1.1		Gas oil CO <sub>2</sub> emission factor is not in the table – please add. Gas Oil CH <sub>4</sub> and N <sub>2</sub> O emission factor can be found in Table 1.3 (Industrial – Heavy Oil)	Gas oil or heavy industrial oil is not considered to be non-variable fuel. Facilities are required to apply the applicable tier level to calculate emissions from combustion of these fuels. Facilities may submit a deviation request if required.
23	23				Table 1.3		Bio-diesel CH <sub>4</sub> and N <sub>2</sub> O emission factor is not in the table – please add. Bio-diesel CO <sub>2</sub> emission factor can be found in Table 14.1 (Page 60)	Biodiesel emission factors for CH <sub>4</sub> and N <sub>2</sub> O are added in Table 1-1.
24	21				Table 1.2		Table 1-2 is only for Natural gas. Can it be applied to other gaseous fuel? e.g. Refinery fuel gas and produced gas. If not, what is the guidance for the CH <sub>4</sub> and N <sub>2</sub> O emission factor for other gaseous fuel?	Refer to Table 1-3 for default emission factors for other fuels, which includes still gas also known as refinery fuel gas. If an emission factor is not available for CH <sub>4</sub> and N <sub>2</sub> O, the facility is required to apply an emission factor that would best represent the gaseous fuel. The selection of emission factors should be provided in the facility's QMD submission if reporting under CCIR.
25	19						It has been removed that "CH <sub>4</sub> and N <sub>2</sub> O emission factor of gaseous fuel in Table 1-3 are based on an average natural gas high heating value of 1020 Btu/scf" (Previous version). Is 1020 Btu/scf still be a reference if the default emission factor unit is tonne/m <sup>3</sup> ? If no, can the same default EF (tonne/m <sup>3</sup> ) be applied to NG with various HHV? Or EF with tonne/GJ needs to be applied for NG with various HHV? Please clarify.	Emission factors based on an energy and mass unit are prescribed. For emission factors that are based on a volume or mass basis, there is an assumed HHV for the fuel. For emission factors that are based on USEPA AP-42 emissions factors in Table 1-2, the default HHV is 1020 Btu/scf. The preference is for facilities to apply the energy based emission factor with an actual HHV; however, it has been communicated to ECCC and ACCO that in some cases, obtaining actual HHVs may not be possible. In this case, where permitted, the facility may apply a volume or mass based emission factor.

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26	Page 18 & Line 7-11 Page 68 & from Line 41						On Page 18, it is indicated that hourly CO2 mass emissions can be calculated by using methodologies required by the applicable regulatory requirements (i.e. facility's AER or EPEA approval) – the AER method for missing data estimate is different from Section 17.4.2 (Page 68 from Line 41). Please clarify.	The facility should use the missing data estimation methodology prescribed in Chapter 17.
27	65		Technical		Table 17.3		Please explain the definition for Tier 1/2/3 for Boiler efficiency	Facilities are required to assess the boiler efficiencies per the applicable tier if boiler efficiency is a necessary parameter in calculating emissions for the facility (Ex. Chapter 14 Quantification Methods for Carbon Dioxide from Combustion of Biomass).
28	11		Definitions- Negligible emission sources				For a facility with TRE = 1,000,000 TCO2e, the current negligible threshold is 1% of the TRE (10,000 TCO2e) up to 1,000 TCO2e (0.1%). Requiring to follow QMD with the current negligible definition for up to 1,000 TCO2e would require investments/cost that do not increase accuracy of TRE. There is no benefit to the environment for these investments. The recommendation is to change the absolute limit to 10,000 TCO2e: "Negligible emissions sources" are sources that represent less than 1% of a facility's total direct CO2e equivalent emissions (CO2e) and are not to exceed limit of 10,000 tonnes of CO2e" The change would avoid investments that do not improve the accuracy of the quantification of facility's TRE. The accuracy of the TRE amount would not be impacted given the absolute threshold of 10,000 TCO2e is significantly below the uncertainty of the main source measurement for facilities with emissions > 1,000,000 TCO2e. This proposal is more stringent than the Ontario regulation that allows for alternate methodologies to be used for the lesser of 20,000 TCO2e or 3 percent of TRE, ref. On.143/16 4(4).	Refer to updated definition of "negligible emission sources".
29	16		1.2.4 Tier 3-CO2 emissions from variable fuels based on the measured fuel carbon content				For Refining combustion sources, table 2 (pg. 27 of 37) from the "Standard for Completing GHG Compliance and Forecasting Reports" specifies the requirement to follow Tier 3 procedure. Since Tier 3 (per the latest QMD version) is specific to variable fuels, therefore a guiding comment somewhere under the Tier 3 section of QMD to direct readers to Tier 1 for non-variable fuels would be helpful in preventing any confusion between QMD and Standard table 2 interpretations.	See response to Comment #6.
30	16	17-19	1.2.4 Tier 3-CO2 emissions from variable fuels based on the measured fuel carbon content				Current text in QMD: "For FCC processes, the emissions are considered to be stationary fuel combustion; however, there are no quantification methodologies currently prescribed. Facilities performing these processes may develop their own quantification methodologies until such methodologies are provided in this chapter. "Please clarify that for the FCC process sites can continue to follow their existing practices around sampling, measurement and data management (vs. Chapter 17) until such methodologies are available in the QMD. For example: Applying existing QMD procedures (in Ch-17) to backfill data concerning FCC (coke burn, flue gas composition etc.) would not be an accurate approach.	See response to Comment #6.
31	21	9			Table 1-2 Default CH4 & N2O EFs for NG		Per ACCO "Summary of Stakeholder Questions and Comments to the Draft Quantification Methodologies (Postings 1 and 2)", comment # 142 unit conversion calculations were performed based on USEPA AP-42. However, in an example below, following the same standard outputs slightly different result: For e.g. NOx controlled/uncontrolled CH4 EF in table 1.4-2 of AP-42 is 2.3 lb/mmscf or 9.693E-07 tonnes/GJ (2.3/1020*1/1055*1/2.205) vs. 9.702E-07 tonnes/GJ in table 1-2 of the quantification document (1020 in the above eq. is a factor to convert lb/mmscf of NG to lb/mmbtu; from AP-42).	See response to Comment #7.

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This table summarizes the questions and comments received by April 25, 2018 for the 3rd posting of the quantification methodologies.

#	Page #	Line	Clause/ Section	Intro Section	Table	Equation	Comment/Question	Responses
32	48		Sec 13.12 Refining- Introduction and CCIR Schedule 2 Established Benchmarks for Products, Definitions, 1(1)(g) "refining" (p. 40-42)				<p>Current definition: "refining" means any manufacturing or industrial process that occurs at a refinery at which crude oil or bitumen is processed or refined into a transportation fuel. Recommendations:</p> <ul style="list-style-type: none"> <li>• Add to the refining definition a minimum percentage of liquid petroleum product produced at a facility. Consider aligning with ECCC definition from OBPS Petroleum Refining Section Working group meeting Mar 1 2018 slide 9-10.</li> <li>• When the upgrading benchmark is added to Schedule 2 (CCIR Established Benchmarks for Products), the upgrading definition should include a maximum percentage of liquid petroleum product produced at a facility.</li> </ul> <p>Reasons: To provide a quantifiable distinction between upgraders and refiners and avoid overlapping definitions.</p>	See response to Comment #8.
33	61		17.0 Measurement, Sampling, Analysis and Data Management requirements				<p>In ACCO's "Summary of Stakeholder Questions and Comments to the Draft Quantification Methodologies (Postings 1 and 2)", comment # 316 the response is "Intend to require all chapters (such as flaring and venting) to follow methodologies prescribed in Chapter 17 and Appendix C..." Our understanding it that the requirement to follow Ch-17 will become effective only after the publication of associated (venting, flaring etc.) chapters? Please confirm</p>	See response to Comment #9.