Canadian Petroleum Products Institute | Institut canadien des produits pétroliers

February 5, 2009

Mr. Jim Norton
Reporting Subcommittee Chair, Western Climate Initiative
Office of the Secretary
Environmental Protection Division
New Mexico Environmental Department
New Mexico, U.S.A.

Re: WCI Greenhouse Gas Reporting Proposal – Canadian Petroleum Products Institute Input

Dear Mr. Norton:

This letter contains input from the Canadian Petroleum Products Institute (CPPI) to the Western Climate Initiative Greenhouse Gas Emission Reporting Proposal posting. The Canadian Petroleum Products Institute (CPPI) represents the majority of the Canadian petroleum downstream industry (refining/distribution/marketing). CPPI members have refinery operations in the provinces of Ontario, Quebec, British Columbia, Alberta, Nova Scotia and Newfoundland & Labrador. On behalf of its members, CPPI works with governments and others to create responsible standards, laws and regulations to safeguard the community, workplace and environment. The input from CPPI is contained in this letter and attached two Appendices.

CPPI supports having appropriately accurate emission inventories and has been working with governments for over 30 years with that objective. However, in an overall sense, there is a need for balance between reporting accuracy and the effort / cost associated with WCI recommended reporting. CPPI prefers that the effort / cost be directed towards achieving actual GHG reductions over the reporting accuracy.

No consideration of cost / complexity of compliance vs. information value to regulators

- The proposed approach is very detailed without an assessment of the total cost of the proposed reporting and monitoring requirements, or an analysis of cost alternatives and impacts, or reflection of consideration of other substantial work seeking cost-effective approaches, such as that of the American Petroleum Institute. There needs to be a more balanced approach between data accuracy and cost of implementation / compliance through the use of a stringent cost / benefit analysis completed prior to finalizing decisions.
- The proposed measuring accuracy exceeds materiality. Five percent accuracy is not realistic, especially at a point source level. There is no justification for the three percent / 20 Kt threshold below which sources would still be reported, but with more simplified methodologies.
- The methodologies require unreasonable effort to quantify sources that are smaller than the inaccuracies in more substantial sources, and there is an unnecessary level of reporting detail (e.g. GHG emissions by fuel type).

Need for Consideration of the Canadian Situation

- The proposed Mandatory Reporting does not address how it will fit into the existing Canadian reporting, emission control, and legal processes. You should be aware that Canadian refiners and other large final emitters have established experiences with the Canadian federal, Alberta and Québec governments, and we have gone a long way in establishing convergence between the regulators' needs and a reasonable burden on reporting entities. CPPI supports the Canadian model where industry has the flexibility to use credible existing sector methodologies per current reporting requirements and jurisdictional practices, rather than the prescribed proposed WCI approach.
- The document does not reflect consideration for the extensive consultation conducted on GHG reporting in Canada, existing GHG reporting processes in Canada, existing energy reporting to Statistics Canada, or the third party verification process in Alberta.
- The WCI proposes regulations that are based on U.S. federal and California laws. In the interest of providing seamless interjurisdictional cooperation, full consideration must be given to practices already in place in Canada. While CPPI would agree that we may have lessons to offer, it is important that the principle of consistency be applied. At a minimum we would question why Canadian definitions can not be used given that they are already in place.
- There is no need for the reporting proposal to be so prescriptive, as process emissions can be unique, and will vary by sector and facility. In some cases, the proposed methodologies are inappropriate for the nature of the process (further explanation in the Appendices).

Inadequate Protection of Business Confidential Information

- The considerations given to confidentiality are not satisfactory (see Appendix 1 attached). Only aggregated data should be released beyond the site level.

Inadequate Consultation Time

- It needs to be noted that there has been inadequate consultation time on this extensive document. The document provides significant new technical, policy, reference, regulatory text, and legal information. It is unreasonable to expect stakeholders to review the document, compare it against other documents, agreements and reporting requirements, consult with knowledgeable people and provide comments in the limited time afforded. Our Canadian experience with the development of reporting requirements demonstrated the need to be rigorous in explaining why data is required and the need to compare that with compliance costs and value. CPPI reserves the right to identify additional items in the future.

As the reporting proposals are developed, we request receiving the draft source category emission quantification and monitoring methods.

Finally, let me reinforce that the time given for this dialogue is unnecessarily short to fully assess the requirements, let alone assess the cost impact of the detailed data tracking, monitoring, reporting, and compliance requirements, and that this document does not reflect the Canadian experience at developing reporting requirements,

Sincerely,

Peter Boag
President
Canadian Petroleum Products Institute

Appendix 1
Comments on the Main Body - 'Requirements of Mandatory Reporting for the WCI, Third Draft'

Applicability WCI.1

- The proposed 10,000 tonne CO2e per year reporting threshold is too stringent and would place an undue burden on small and medium sized operations. In addition, it is 25,000 metric tons CO2 per year in the California rule, and the same inclusion in the WCI cap-and-trade program. It becomes particularly problematic when linked to the yet to be defined reporting requirements for fuel providers. This 10,000 metric tons CO2e/year threshold goes beyond the scope of any reporting protocols that are in place in the, EU, the US or California. Further, how this would be implemented, how suppliers would comply, and how it interacts with other provisions of the reporting requirements is a particularly complex issue with significant potential confidentiality issues?
- What is the basis for the documents incorporated as references? They are initially limited to ASTM, California requirements, EPA Tanks and a document from the Gas Processors Association. The petroleum sector, led by the API and CONCAWE, in broad consultation with governments and other international stakeholders has been working on GHG quantification methodologies and practices for many years. Existing industry practices should be incorporated. (p. 1-9).

General GHG Reporting Requirements and Schedule WCI.2

- The desire for accurate reporting of GHG emissions must be balanced with efforts directed towards identifying opportunities to reduce GHG emissions i.e. avoid diverting limited resources to obtain precise GHG emission reports at the expense of stifling activities devoted to reducing GHG emissions.
- The principle purpose of this framework is to allow for a market exchange of credits as a mechanism to comply with GHG reductions. CPPI believes the reporting system as described could inhibit timely business relevant decisions aimed at reducing GHG emissions or at least complying to permit exchanges.

Timing

- The recommended 2010 start date is a very short time period for each of the individual provinces and states to move their implementing regulations through their regulatory processes, and for facilities to get their programs designed, any new required measurement equipment in place, and to have their people trained. This creates an opportunity for uneven playing fields if jurisdictions are not all ready at the same time. Consideration should be given toward a staged approach.

Appendix 1 continued

General GHG Reporting Requirements and Schedule WCI.2 continued

Fuel Use Measurement Accuracy

- The use of Continuous Emission Monitoring Systems (CEMS) for specific measurements is a vivid example of a particular concern in the perspective of both no consideration of cost and little concern of the Canadian situation. The use of CEMS is not a common practice in Canada. Adoption of this measurement technique will be extremely costly to the Canadian petroleum industry without assurance of greater accuracy or efficiency let alone the reduction of GHG emissions. CEMS require high capital investments, high costs for operation and maintenance, and long lead time to install. E.g. Quality Assurance accordance with the AB code of practice (similar codes in place for ON too, and maybe other jurisdictions - tbc) for one CEMS for SOx and NOx is approximately $100,000 per year. For one facility with multiple stacks, quality assurance of multiple CEMS could be in the order of millions. Such an investment needs to be weighed against the gain in accuracy from inventory calculations.
- The general requirement for fuel use accuracy will be difficult for many existing meters to meet. Depending on the meter, service and installation, it may not be possible to maintain and calibrate "in a manner and a frequency required to maintain this level of accuracy" short of completely replacing measure devises or forcing the unscheduled shutdown of operating facilities for the installation, maintenance and/or calibration of flow meters – none of which are viable alternatives.
- The proposed accuracy of ±5 percent in quantifying fuel use (p. 15) is not realistic, given technical limitations around flow meters to measure to this level of accuracy, especially at the level of source detail proposed. It would be more practicable for facilities and enforcement to have one overall accuracy level for the total inventory.

Reporting

- An annual reporting deadline of April 1 is needlessly aggressive and doesn't recognize the multiple existing reporting requirements. CPPI recommends one standard reporting standard with a standard deadline to the jurisdiction that holds responsibility for regulatory enforcement.
- Quantification of emissions from transportation fuels should be simple, with common methodology (e.g. fixed carbon content for fuel types) consistent with any existing fuel regulations.
- Has the WCI considered the experience of verification and verification requirements of jurisdictions such as the province of Alberta? How do the proposed requirements for third party verifiers compare to those in Alberta?
- Consider using existing reporting systems where they exist in jurisdictions, until acceptable consistent longer-term WCI reporting requirements can be determined.

Contents of GHG Emissions Report WCI.3

- There should not be a need to report ancillary data, production quantities, fuel consumption and emission breakouts to government. This information can be kept on site

Appendix 1 continued

Document Retention and Record Keeping Requirements (WCI.4) - Confidentiality

Inadequate Protection of Confidential Business Information

- The WCI proposes that detailed information, including proprietary business information that can be used to determine competitor costs, be reported to the WCI, stored in a database under foreign jurisdiction (from a Canadian perspective), and be made available to the public with minimal exceptions. This raises a number of concerns over confidentiality.
  - The rule should be that company specific data is by definition confidential.
  - Regulators must have in place legally enforceable mechanisms to protect confidentiality.
  - Decisions on the treatment of data in the database from Canada should be under Canadian laws, not under the laws of the United States.
- While data such as site aggregated emission data should generally be available to the public, distribution of proprietary data (production data and disaggregated data) should be protected. Third party verification gives assurance to the public that reported emissions information is accurate without the need to reveal sensitive business information or trade secrets.
- The statement: “In general, emissions data submitted to any WCI Partner jurisdiction under the reporting rule are public information and shall not be designated as confidential. (p.21)" is far too broad and not supported. The WCI should specify what data will be made public (e.g. aggregated site emissions).
- There should not be a need to report ancillary data, production quantities, fuel consumption and emission breakouts to government. This information can be kept on site
- WCI is proposing using a central repository implemented by TCR (California based "The Climate Registry") for data storage.
  - Reporting should be limited to the regulating jurisdiction, with only aggregated non-proprietary data reported to the WCI.
  - There is no cost basis for the selection of The Climate Registry as the proposed manager of the WCI's database.
- The requirement to retain all facility GHG reporting documents and records for a minimum of seven years is too long, and will impose an additional administrative burden on reporting firms. A mandatory record-keeping period of no more than five years is recommended, and the three years required by Alberta's Specified Gas Reporting Regulation preferred.

Compliance and Enforcement (WCI.5)

- Enforcement, including specification of violations (e.g. "Each violation of this rule shall be considered a single, separate violation for each day beyond the specified reporting date.") must be left to the regulating jurisdiction, not the WCI.
- Reporting facilities should be given sufficient time to rectify any concerns with respect to reported emissions prior to having penalties imposed on them..
- Regulators should not have open access to verification meetings and site visits outside their jurisdiction (p. 29). Verification meetings should be limited to regulating jurisdictions (who are regulated to protect competitive information), and third party verifiers (who should sign confidentiality agreements). Third party verified reports accepted by WCI jurisdictions should not be subject to additional enforcement requirements. Care must be taken to accredit qualified and competent verifiers and accountability for correctness of the report should then transfer to the verifiers. Only unverified, self certified reports should be subject to enforcement.

Designated Representative (WCI.5)

- Requirements for designated representatives should be set by the regulating jurisdiction, based on shared reporting principles with respect for differing regulatory and compliance approaches.

Appendix 1 continued

Requirements for Verification of Emissions Data Reports (WCI.8)

Require a Common Approach to Quantification and Assurance

- Consideration needs to be given to a materiality threshold.
- CPPI supports the Canadian model where industry has the flexibility to use credible existing sector methodologies per current reporting requirements and jurisdictional practices, rather than the prescribed proposed WCI approach.
- It is important that WCI and its partners have consistent, comparable, compatible, generally equivalent verification protocols so that companies that have facilities in different partner jurisdictions can avail themselves of properly trained verifiers that are eligible to verify emission reports for their different operations in the different jurisdictions. In addition, this will allow for an expanded pool of trained verifiers, most importantly it will establish the credibility need with potential future trading partners/jurisdictions.
- It is important that third party verifiers be impartial. The requirement to pre-authorize or requirement to accredit verifiers on a facility-specific basis will needlessly increase the time required to complete reporting, and could result in substantial problems in the event that there is a need to change verifiers late in the submission cycle. This will require time to develop this standard for verifying, to train people and to certify them. This puts timeline at risk (related to comments on trade off between time to implement and prescriptiveness). Verifier needs to be familiar enough with processes and facilities to be able to know if the methodology will work and flexibility of methodology is needed.

Appendix 2
Comments on the Attachments to 'Requirements of Mandatory Reporting for the WCI, Third Draft'

Attachment 1: General Provisions

- What is the basis for the definition of "facility"? The definition used in regulations under the Canadian Environmental Protection Act would be preferable to minimize confusion for Canadian industry. The proposed definition differs by introducing the requirement that operations in the facility have the same first two digits of the SIC or same first three digits of the NAICS code. What are the implications? Are Canadian regulators willing to modify their definition?
- What is the justification for the proposed requirement for detailed reporting? (p. 2-1) Emission quantification can be verified by government and third party verifiers. The reporting of the following needlessly puts competitive information at risk by facilitating the estimation of competitor's costs.
  - GHG emissions by fuel type
  - annual fuel consumption
  - carbon content of fuel
  - heating value of fuels
  - amount of steam generated
- This is too much to disclose (see comments under confidentiality and reporting). This detail should be resident at a facility and accessed on a verification/audit basis, not reported to the regulator.
- There should not be a requirement to report ancillary data such as production quantities, fuel consumption and emission source control breakouts.

Attachment 2: General Stationary Combustion

Calculation of CO2 Emissions WCI.23 (c) - Calculation Method 3

- The Molar Volume Conversion factor listed is for a set of standard conditions of 20 deg. C. and 1 atms. vs. the industry's set of standard conditions of 60 deg. F and 1 atms. Calculation method 3 should show a second MVC for these conditions as is done in Equations 200-3, 200-9, and 200-11 in the Refinery Section.

Sampling, Analysis and Measurement Requirements WCI.25 (c)

- The requirement for 'On line instrumentation used to determine higher heating values must be accurate to with in 5 %' is not reasonable, nor would it provide more accuracy than a frequent lab test would provide.

Sampling, Analysis and Measurement Requirements WCI.25 (d) – Fuel Carbon Content

- The ASTM methods listed in (d)(3) do not adequately capture heavier olefins compounds that will be present in some refinery process gas streams – particularly from FCCs and Cokers. The language should be modified to allow people to extend the ASTM methods to adequately capture these compounds – otherwise we will be under reporting. Quantification methodologies for stationary combustion refer to US regulations (e.g. 40 CFR Part 60)
- Do not support annual testing frequencies for sour gas. The current frequency is acceptable to regulators.

Appendix 2 continued

Attachment 3: Refinery Fuel Gas Combustion

Definitions

- CPPI recommends including a definition of the different type gasses associated with this section – in particular, definitions for refinery fuel gas, flexigas, still gas and associated gas are needed.

Calculation of GHG Emission WCI.33

- The sampling requirements for carbon content for refinery fuel gas are excessive. This is particularly true for refineries that do not have continuous HHV/LHV or carbon content analyzers.
- The requirement that 'The carbon content of refinery fuel gas must be determined 3 times daily using on-line instrumentation of discrete lab analysis; once per day for flexigas' is not reasonable. This is too stringent and will take significant resources and long lead time to implement.

Attachment 7: Hydrogen Production

- The measurement of feedstock adds monitoring costs to the system without yielding any benefit towards the quantification of GHG emissions from the hydrogen plant or identification of GHG emission reducing activities.

Sampling, Analysis, and Measurement Requirements WCI.134(b)(3)

- Section WCI.132(c) requires the measurement of the daily hydrogen production. This flow measurement is not used to calculate emissions, so it should not be subject to the accuracy provisions in WCI.2 (g).

Attachment 10: Petroleum Refineries

Overall Comments

- To maximize the use of a 'preferred' method and 'alternate method approach', CPPI recommends the API Compendium to estimating GHGs, to provide flexibility.
- What is the justification for the proposed requirement for detailed reporting? (p. 10-1) Emission quantification can be verified by government and third party verifiers.
- What is the justification for the proposed requirement for detailed reporting? (p. 7-1) Emission quantification can be verified by government and third party verifiers. *The reporting of the following needlessly puts competitive information at risk:*
- Feedstock consumption by type
- Fuel consumption by fuel type
- What is the justification for requiring the quantification of emissions that are not material compared to other refinery sources?
- Quantification of fugitive emissions should be consistent with Canadian LDAR practices (see CPPI Emission Code of Practice) to reduce the confusion due to multiple basis for calculations. LDAR requirements should not be more severe than current Canadian jurisdictional requirements.

Appendix 2 continued

Attachment 10: Petroleum Refineries continued

Calculation of Emissions WCI.203

- The standard conditions specified for calculating emissions from the combustion of gaseous fuels is inconsistent in the different attachments that provide the calculation details.
- In some of the equations for quantifying emissions two options are provided for the molar volume conversion factor, while in others only one option is provided. All the equations specify a molar volume conversion factor of *849.5 scf/Kg-mole,* which is applicable for a temperature of 20C and pressure of 1atm. A few of the equations provide an option for using an alternative molar volume conversion factor of *834.5 scf/Kg-mole*, which is consistent with industry standard conditions of a temperature of 60F (~ 15C) and a pressure of 1atm. These industry standard conditions are used throughout the U.S. in ASTM standards and in specifications for petroleum and natural gas transmission and distribution, as defined in section 3.5 of the API GHG Methodology Compendium (February 2004).
- Hence, while the difference between the two molar conversion factors is only about 2%, we would recommend that all the equations allow the flexibility of using either of the molar conversion factors in order to properly accommodate industry data without the undue burden of having to convert all the measurements to a different set of standard conditions.

Calculation of Emissions WCI.203 (e) – Flares and Other Control Devices

- The definition of process vents needs to be clarified. Quantification of process vents to flares may result in the overestimation of overall GHG emissions.
- The API GHG methodology compendium address flare emissions by using the two equations below: the equation for CO2 accounts for the possibility that CO2 is present in the flared gas stream and would be emitted with the flare exhaust, while the equation for CH4 assumes 0.5% residual, unburned CH4 remaining in the flared gas based on industry practice for well designed and operated flares, such as in refineries.

$$\mathrm{CO_2\ Emissions} = \mathrm{Volume\,Flared, Mscf} \times \frac{1000\,\mathrm{scf}}{\mathrm{Mscf}} \times \mathrm{Molar\ volume, } \frac{\mathrm{lbmol}}{379.3\,\mathrm{scf}} \times \left[\sum \left(\frac{\mathrm{mole\,Hydrocarbon}}{\mathrm{mole\,gas}} \times \frac{A\,\mathrm{mole\,C}}{\mathrm{mole\,Hydrocarbon}} \times \frac{FE\,\mathrm{mole\,CO_2\ formed}}{100\,\mathrm{mole\,C\ combusted}} \right) + \frac{B\,\mathrm{mole\,CO_2}}{\mathrm{mole\,gas}} \right] \times \frac{44\,\mathrm{lb\,CO_2}}{\mathrm{lbmole\,CO_2}} \times \frac{\mathrm{tonne\,CO_2}}{2204.62\,\mathrm{lb\,CO_2}}$$

$$\mathrm{CH_4\ Emissions} = \mathrm{Volume\,Flared, Mscf} \times \frac{1000\,\mathrm{scf}}{\mathrm{Mscf}} \times \mathrm{Molar\ volume, } \frac{\mathrm{lbmol}}{379.3\,\mathrm{scf}} \times \frac{C\,\mathrm{mole\ CH_4}}{\mathrm{mole\ flared\ gas}} \times \frac{0.005\,\mathrm{mole\ residual\ CH_4}}{\mathrm{mole\ CH_4}} \times \frac{16.04\,\mathrm{lb\ CH_4}}{\mathrm{lbmole\ CH_4}} \times \frac{\mathrm{tonne\ CH_4}}{2204.62\,\mathrm{lb\ CH_4}}$$

- CPPI recommends that these two equations be used by jurisdictions that do not have flaring regulations in place, while the methods specified by local jurisdictions should be used for reporting when flaring measures are in place. In addition, if the flares are equipped with natural gas pilots, average annual carbon content and heating values provided by the fuel supplier should suffice as the basis of calculating the contribution of these pilots to GHG emissions from the flares.

Appendix 2 continued

Attachment 10: Petroleum Refineries continued
Calculation of Emissions WCI.203 (i)
Equipment Leaks:

- API has conducted a study to quantitatively assess the contribution of fugitive CH4 emissions from equipment leaks to the overall refinery GHG emissions. Those emissions were estimated based on counts of components in natural gas and refinery fuel gas service using conservative average emission factors for components in gas service at refineries, as provided by the USEPA 1995 Protocol. The calculation of CH4 fugitive emissions from equipment leaks were performed for two refineries: the one a smaller fuels refinery with a rated capacity < 100,000 Bbls/day, and the second a larger refinery/petrochemical complex of about 200,000 Bbls/day. For the smaller refinery GHG emissions were 669,829 tonnesCO2E/yr, with CH4 from equipment leaks amounting to 765 tonnes CO2E/yr (or 0.11% of total GHG). For the larger refinery, GHG emissions were 1,474,896 tonnesCO2E/yr, with CH4 from equipment leaks equal to 2,759 tonnesCO2E/yr (or 0.19% of total GHG). .
- CPPI recommends adopting the API approach as it specifies in its GHG Compendium. This approach relies on an initial estimate of these emissions, using equipment counts and average emission factors, which are very conservative. Only if these emissions exceed the deMinimis threshold would refineries have to adopt a more refined approach, such as using either a Leak/No Leak or a screening value correlation equation approach, as specified in existing guidance documents.

Calculating CH4 emissions from refinery aboveground storage tanks

- EPA TANKS Version 4.09D is not capable of directly estimating CH4 emissions from crude oil tanks because CH4 does not follow Raoult's Law, and the default crude speciation profile in EPA TANKS does not include CH4, some back-end refinement of the EPA TANKS estimate is needed. Some of the key technical issues associated with using EPA's TANKS are:
  a) EPA TANKS is based on the methods presented in Section 7.1 of EPA's AP-42 guidance document. The TANKS program is most appropriate for estimating standing (storage or breathing) losses and working losses from fixed rood tanks, or in the case of floating roof tanks, withdrawal and standing losses.
  b) The emission estimation in TANKS and AP-42 are based on using Raoult's Law to estimate the emissions, which relates the vapor pressure of the specific compound in the liquid mixture to the total mixture vapor pressure. Raoult's Law assumes an ideal gas in the vapor phase and an ideal solution in the liquid phase. Such an assumption is valid for hydrocarbon compounds that are liquids at ambient temperature, and EPA TANKS can therefore be used to estimate emissions from these VOC compounds.
  c) CH4 is a very volatile compound, with a boiling point of -258.7°F. It therefore has a very strong affinity for the vapor phase. According to Perry's Chemical Engineer's Handbook, CH4 has a vapor pressure of 588 psia at -123.3°F. Therefore, due to the high volatility, one would not expect much CH4 in crude oil when it arrives at a refinery. The default crude oil speciation data in the EPA TANKS program does not list CH4 as one of the compounds.
  d) The Henry's constant for CH4 is also large, at 35,390 atm/liquid mole fraction (in water), based on data in the literature, which further confirms that CH4 has a strong affinity for the vapor phase, and would therefore be expected to volatilize upstream of the refinery.
- The API Compendium (Section 5.4.2, February 2004) discusses a conservative approach for estimating CH4 emissions from petroleum storage tanks (non-flashing losses) that is designed to account for the potential of a minute amount of CH4 still being present in the crude oil. The method would include estimating THC or VOC emissions from EPA TANKS, and then multiplying the resulting emissions by an assumed CH4 concentration in the vapor.
- Such an approach would likely overestimate CH4 emissions, and may even double count emissions that have already been estimated in the upstream sector. Therefore, we suggest making this requirement optional and applicable only to the storage of crude oil and not to any refined products.

Attachment 10: Petroleum Refineries continued

Monitoring Requirements WCI.204:

- In general this section attempts to extract and re-summarize monitoring requirements outlined for each of the calculation methods outlined in the proceeding section WCI.203. In doing so, WCI 204 creates a number of significant issues that conflict with other provisions of the regulation, over specify accuracy requirements for measurements not used to calculate emissions, and creates new measurement or sampling requirements otherwise not required by the regulation.

  WCI.204(a)(1) Catalyst Regeneration – for FCCs. Equation 200-3 describes how to calculate the flow rate of exhaust gas from a fluid catalytic cracker regenerator based on the flow rate of air to the regenerator, the flow rate of O_2-enriched air to the regenerator, the concentrations of CO_2, CO and O_2 in the exhaust gas and concentrations of O_2 in the O_2-enriched air. However, WCI.204 – Monitoring Requirements, Section (a) (1) (C) requires the "continuous measurement of the volumetric flow rate of exhaust gas leaving the regenerator". Given that the flow rate of exhaust gas is calculated according to Equation 200-3, there is no need to measure the flow rate directly. In addition many refineries do not have capability to measure the flow rate of exhaust gas from the regenerator. This provision should be deleted from the rule

  WCI.204 – Monitoring Requirements, Section (a) (1) (E) requires "daily measurements of the carbon content of the coke burned" during catalytic regeneration. Coke is a by-product of fluid catalytic cracking and forms on the catalyst during the reaction. The catalyst is continuously circulated through the catalytic regenerator in order to burn off this coke. Fluid catalytic cracking and catalyst regeneration occur continuously 24 hours a day within a closed system and trying to directly measure the carbon content of coke creates a number of safety issues. Therefore, the carbon content of coke should be calculated from a heat and mass balance around the unit as required in WCI.203 (a)(1), and this provision should be deleted from the rule.

  WCI.204, Section (a) (1) (D) requires "continuous measurements of CO_2, CO and O_2 concentrations in regenerator exhaust gas." Refineries may not currently have the equipment to provide continuous measurement of CO_2 or CO. CPPI recommends that the WCI provide the option of periodic sampling of CO_2 and CO as an alternative to continuous measurement.

  Other Activity Measurements in Sections WCI 204.(b) through (i) link accuracy requirements for "activity" measurements (wastewater flow, sludge flow, storage tank volumes, etc.) to the fuel use accuracy requirement in WCI.2(g). Many of these source categories are potential candidates for the use of the de minimis provisions of the Essential Requirements. This essentially hardwiring of mandatory measurement accuracy either defeats the purpose of the de mimimis provision, or adds costly monitoring requirements that may not actually be used for calculating emissions. These mandatory requirements should either removed completely, or conditioned to be used only for those measurements being used to calculate emissions.

Default Factors

- The sulfur plant methodology requires a default factor of 0.2 or a "source specific molecular fraction value approved by...and derived from source tests..." 0.2 is conservatively high. Using unspecified source testing could be costly for relatively small source. The default conversion factor of 0.6 from non-methane VOC to methane is not technically supported. CPPI recommends that a generic conversion factor of 0.15 be used in accordance with the recommendations of the US EPA in AP-42. This could serve as a more realistic default conversion factor and facilities should be allowed to use their best available information on the actual CH4/NMHC or CH4/NMVOC ratios of their applicable streams from which GHG emissions are reported.