Best Practices Learned from Greenhouse Gas Reporting

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INTRODUCTION

Over the past nine years, greenhouse gas (GHG) emission reporting programs have developed at the state and federal levels and have slowly been synchronized. These separate programs initially produced a variety of rules, regulations, requirements, and guidance, which created a number of parallel but similar reporting methodologies. Over time the rules have generally harmonized with the U.S. Environmental Protection Agency's (EPA's) GHG reporting program (GHGRP), and best practices have developed which can be applied to most GHG emission monitoring and reporting programs. The procedures for GHG reporting for stationary combustion and process emission facilities such as power plants, cement plants, and landfills have slowly evolved over the past nine years, resulting in a variety of best practices learned by the industries.

This paper details various procedures learned at the state and federal level for GHG reporting, which represent best practices. These include procedures for monitoring plan development, training, metering [including requirements for both third party meters (e.g. utility meters) and operator operated meters], fuel quality and analysis (e.g. continual gas analyzers, higher heating values [HHV] from utility records, laboratory carbon content analysis), tiered reporting methods (e.g. EPA's Tier 1-4 methodologies), and continuous emission monitoring systems (CEMS) usage verse actual fuel flow. This paper also discusses how the selected tier impacts the level of effort, resources required and the accuracy of the reported emissions.

This paper assesses how Title V facilities, such as power plants, cement plants, and landfills, have been affected by GHG reporting programs and what best practices have been developed. This assessment includes a discussion of monitoring of data; calibration requirements; third party audits/verification; and what additional monitoring and recordkeeping programs have been implemented.

MONITORING PLAN DEVELOPMENT

All facilities reporting their GHG emissions per the EPA's GHGRP are required to have a GHG monitoring plan per 40 Code of Federal Regulations (CFR) 60 Section 98.3(g)(5). At a minimum, the following elements must be included in each plan:

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data.
- Explanation of the processes and methods used to collect the necessary data for the GHG calculations.
- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

In addition to these requirements, each subpart of the GHGRP has additional GHG monitoring plan requirements that must be included in a facilities plan. GHG monitoring plans vary from one-page forms to multi-document standard operating procedures (SOPs) for how to document, report and maintain a GHG reporting program at a facility. The needs and complexity of the reporting facility determine how complex and robust a monitoring plan should be.

We have found that it is best practice to start with the GHGRP monitoring plan minimum requirements and then going through the applicable subparts. Next, incorporate state and local rules, such as California Air Resource Board (CARB) mandatory GHG reporting rule requirements, into the plan. It is also best practice to include each rule's regulatory citation in the plan so it easy to track back to the regulation with which it is associated and know to which program it is applicable.

Monitoring plans should not just state the regulatory requirement but should detail the "what," "when," "where," and "how" a facility is complying and meeting the regulations requirements. For example, stating that a flow meter is used is not enough; the monitoring plan should have the type, make, model of the flow meter as well as the location, installation date, and most recent calibration information. This information requires that a monitoring plan be updated anywhere from quarterly to annually depending on requirements. This best practice allows a facility to stay up-to-date when equipment is changed or modified.

The best monitoring plans also cover training requirements for facility personnel. By including training in the monitoring plan, it gives a new facility employee a program to learn the skills needed to complete the different monitoring and reporting requirements as well sets forth who is qualified to perform different tasks (e.g. meter calibration, data gathering, reporting). Another monitoring plan best practice is to include a facility diagram showing all destruction devices, monitoring locations, and fuel sources. A facility diagram should not be an engineering drawing but more of a flow diagram, which easily shows how the destruction devices, fuel sources, and monitoring points are related. Finally, a monitoring plan should be sufficiently robust that if the person leading the implementation leaves that position, their successor could read the monitoring plan and understand their duties and responsibilities.

METERING

There are multiple factors that go into a facility's metering locations, which range from facility age, type of operations, and accessibility. The most important factor in metering is the fuel type, which will determine the type of meter you need and the parameters it will need to monitor (e.g. temperature, pressure, and moisture). As such, one of the most common fuel sources at a facility reporting GHG emissions in the U.S. is natural gas from a natural gas supplier (e.g. Public

Utility), which will have a third party meter, also known as a financial transaction meter (e.g. commonly known as a Utility Meter). Financial transaction meters are owned and operated by natural gas suppliers and typically located along a facility boundary or adjacent to a natural gas supplier's transmission line or pressure step down facility. Financial transaction meters are exempt from the calibration requirements of the GHGRP if the supplier and purchaser do not have common owners and are not owned by subsidiaries or affiliates of the same company. The accuracy of these meters is typically monitored by the utility or other state or local departments. Per the GHGRP, if a facility is able to report all GHG sources as an aggregated unit from a common pipe, using a financial transaction meter may eliminate the burden of meter calibration requirements. However, financial transaction meters, just like any other meter, may malfunction or misreport data and if not caught in time by the natural gas supplier, the minimum data capture requirements will not be met. Facilities with an internal meter adjacent to the financial transaction meter to ensure redundancy as well as to cross check the volume of gas received is best practice. Another option is for facility to put flow meters at each destruction device, which would allow them to can aggregate fuel usage across the facility to ensure the financial transaction meter is reading accurately.

Operator-operated meters, also known as internal meters, are used when required by the regulation or permits where individual sources need to be metered for greater unit accuracy. This is common for power generation, cogeneration, biogenic fuel (e.g. landfill gas, mine gas, or digester gas) usage, mixed fuel (e.g. mixture of natural gas and biogenic fuel) usage, cement plants, industrial manufacturing, refining facilities, and any facility which does not purchase fuel from a utility supplier. These types of facilities frequently have multiple destruction devices and/or multiple fuel sources that are being destroyed (e.g. cement kiln burns natural gas, coal, distillate oil, and wood chips). Every fuel source a facility uses may be required to have its own internal meter. GHG metering is required to meet a five percent accuracy requirement for all internal meters, regardless of the type of meter. Calibration is required as specified by the manufacturer specifications if available. If manufacture meter calibration information is not available, calibration should be done under GHGRP Section 98.3(i)(2-3). For orifice flow meters, best practice is to take pictures before and after cleaning of orifice plate annually in addition to performing calibration on all transmitters (e.g. differential pressure, total pressure, and temperature). State and local rules may require more stringent calibration requirements (e.g. CARB requires three calibration points must be used spanning the normal operating conditions).

For all internal meters, best practice is to inspect the meter weekly, document cleaning and or field checks preformed typically quarterly, and calibrate the flow meter annually. As stated above in the monitoring plan section, it is best practice to document all flow meter installations, cleaning, inspections, calibrations, and switching out of meters in the monitoring plan. A facility should have staff who is knowledgeable with each type of meter used onsite and how to perform the aforementioned activities on internal flow meters. Another best practice is to have a spare meter onsite for all meters, which must be pulled and sent into the factory for calibration or in case a meter fails. Using third party calibration services is also a best practice for meter calibration as those individuals are trained on the correct calibration requirements and perform them often versus once every one to five years.

FUEL QUALITY AND ANALYSIS

The three most common sources for fuel quality are values provided by the fuel supplier on a monthly or shipment basis, laboratory results for samples collected at the facility, and onsite analyzers. For purchasers of natural gas or standard distillate fuels, fuel supplier analysis is best practice (e.g. high heating value (HHV) from the monthly natural gas bill). Natural gas suppliers, who operate transmission lines/interstate pipelines, have gas chromatographs located throughout their distribution areas. The continuous gas chromatograph data is used to calculate the HHV supplied on the monthly natural gas invoice. Distillate fuel suppliers store fuel at terminals where the HHV measurement is taken and supplied on the fuel invoice. Therefore, it is best practice to use the fuel supplier provided data on the invoice instead of the default or national average.

For purchasers of a fuel where they make multiple purchases a month from multiple suppliers that are aggregated and stored onsite (e.g. coal or wood chips purchases stored in a silo), taking composite samples and sending it to a lab on a weekly or monthly basis will be best practice. Note the procedure for sampling fuel sources, as well as any required training needed to conduct the sampling, should be in the facility's GHG monitoring plan.

For facilities that destroy off specification fuels, refine or generate their own fuel, or biogenic fuels, a portable or inline gas analyzer may be used. For example, under the EPA GHGRP landfill gas destroyed in a flare, monthly portable readings (e.g. LANDTEC GEM5000) are sufficient to meet the requirements. For an electric power generator or kiln, consistent heat value may be required for consistent operation and in these cases an inline gas chromatograph would be required for operational, permitting, and reporting purposes. It is best practice for either method to take the gas sample or have the equipment inline as close to the flow meter location as possible and not have any equipment, which may alter the fuel quality, between the meters or the destruction device(s). Often a gas analyzer is placed on the main header line as near the field connections to get the field reading, however the fuel may go through processing (e.g. dehydrators and scrubbers) which could alter the gas quality.

TIERED REPORTING METHODS (e.g. EPA'S TIER 1-4 METHODOLOGIES)

The EPA MRR tiered reporting methods have slowly been adopted by state and local GHG programs as the correct practice to use for GHG reporting. An overview of the four EPA GHGRP tiers to calculate CO_2 emissions are shown below:

Tier 1 Mass or volume of fuel combusted per year, default HHV and fuel specific default emission factor provided in EPA Table C-1, and conversions factors to metric tons.

Tier 2 Mass or volume of fuel combusted per year, annual weighted average HHV from valid samples, fuel specific default emission factor provided in EPA table C-1, and conversions factors to metric tons.

Tier 3 Mass or volume fuel, annual average carbon content of the solid fuel, and conversions factors to metric tons.

Tier 4 Quality-assured data from CEMS

As Tier 2 and 3 take into account the actual fuel quality and analysis and Tier 4 monitors actual observed emissions, these take preference over Tier 1 for calculation methods. Best practice is to use as much site specific data as possible, and best practice would be to report using Tier 2, Tier 3, or Tier 4 when the data for these tiers are available. See the section below regarding CEMS (Tier 4) versus Actual Fuel Flow (Tier 1, Tier 2, or Tier 3).

CEMS USAGE VERSUS ACTUAL FUEL FLOW

When calculating GHG emissions, there is typically a one or two percent difference between CEMS and actual fuel flow data (e.g. metered usage). Typically, facilities like 40 CFR Part 75 power plants and cements plants are required to have carbon dioxide (CO_2) CEMS; however, these facilities typically report over one million metric tons of emissions a year. These facilities are still required to meter their actual fuel flows and analyze their fuel quality as discussed above in addition to CO_2 CEMS. For reporting GHG emissions, CO_2 CEMS only measure CO_2; methane (CH_4) and nitrous oxide (N_2O) still need to be calculated using fuel flow and reported along with the CEMS data.

Due to the high cost of installing, operating, testing [e.g. (Relative Accuracy Test Audit) RATA test], continual monitoring, and maintenance of CEMS, unless actually required by a regulation, use of CEMS for reporting GHG emissions is not a cost effective best practice and should only be done if CEMS are required for other reasons. For cement facilities, the CEMS will also monitor the process CO_2 emissions associated with the cement manufacturing process, and will allow a more accurate measurement versus calculating from kiln raw material (e.g. limestone) usage. Best practice for smaller facilities that are not required to install a CEMS would be to continue with actual fuel flow and a lower tier.

THIRD PARTY AUDITS/VERIFICATION

Federal and most state and local GHG reporting programs do not require third party audits or verification, but the use of these audits can help a facility develop a better program, find holes in their system, and identify any areas of inaccuracy in how they have been reporting and allow them to correct them. The CARB Mandatory GHG Emission Reporting and Compliance Offset Programs both require annual verification of all facilities that report over 25,000 metric tons carbon dioxide equivalent ($MTCO_2e$), report under an applicable subpart of the EPA GHGRP (e.g. cement plants), or have a compliance offset project (e.g. livestock, forestry, mine methane capture, ozone depleting substance, and rice cultivation). Massachusetts Department of Environmental Protection (MassDEP) also has a GHG reporting program which requires verification every three years for all facilities which emit over 5,000 $MTCO_2e$ and/or are regulated under Title V of the Clean Air Act and 310 Code of Massachusetts Regulations (CMR) 7.71.

An audit allows a facility to develop practices with monitoring, recordkeeping, meter calibrations, fuel quality, calculation methodology, and reporting for the overall reporting system. Typical audit findings will point out issues like incorrect conversion or emissions factor, use of a straight average instead of a weighted average when calculating annual HHVs, missing some of the required parts of a GHG monitoring plan, doing data substitution incorrectly, and prorating a facilities fuel usage incorrectly. If you are not in a program that requires verification, best practice is to have an internal audit of your GHG reporting system annually and/or a third party audit every three to five years, or when an applicable regulation is changed or updated, a facility's destruction devices or management structure significantly change, or emissions increase significantly (e.g., 25% increase).

SUMMARY

After nine years of GHG reporting, a lot of trial and error and clarifications have resulted in the best practices to follow when reporting GHG emissions federally or at the state and local level. The key is to have reliable, replicable, quality-assured data that can be traced back to its origins (e.g. flow meters and fuel quality analysis, or third party invoices) and a monitoring plan that walks a facility through the data gathering and reporting process. Unless required directly by the GHGRP or other program to report in a specific method, a facility has many options of how to report their GHG emissions. The best practice is to use site-specific data that can be traced back to a third party record or maintained and calibrated metering device and to have a secondary way of reporting GHG emissions to ensure meeting all data capture requirements and compliance.

As discussed above, the GHGRP, Tier 1-4 methodologies of reporting give multiple options for reporting GHG emissions, however the additional one to two percent accuracy will typically not justify the additional expenditure. For these reasons, large stationary combustion emitters (e.g. facilities like power plants and cement plants whom emit over one million $MTCO_2e$) are required to use CEMS but smaller stationary combustion emitters (e.g. facilities like recycled boxboard manufacturing or landfills whom emit 25,000 $MTCO_2e$) use fuel supplier invoices or direct metering. Lastly with any reporting program, audits or third party verification are best practice, as they guarantee all correct regulations and methodologies are implemented, data is accurate and represented accurately, and allow corrections to be made to ensure the most accurate, highest quality information is being reported.

REFERENCES

1. Code of Federal Regulations Title 40 Part 98, Final Rule on Mandatory Reporting of Greenhouse Gases

2. California Code of Regulations (CCR) Title 17 Part 95100-95158, Regulation for the Mandatory Reporting of Greenhouse Gas Emissions

3. Code of Federal Regulations Title 40 Part 75, Continuous Emission Monitoring

4. Code of Massachusetts Regulation Title 310 Part 7.00, Air Pollution Control

5. Intergovernmental Panel on Climate Change, 2007. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, 2007.