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MEMORANDUM

TO: UARG Measurement Techniques Committee

FROM: Ralph L. Roberson, P.E.

DATE: November 25, 2014

SUBJECT: Real Heat Rate Improvement or Measurement Variability/Uncertainty

INTRODUCTION

On June 18, 2014, the Environmental Protection Agency (EPA) proposed emission guidelines for states to follow in developing plans to address greenhouse gas emissions from existing fossil fuel-fired electric generating units.[1] Specifically, the EPA is proposing state-specific rate-based goals for carbon dioxide emissions from the power sector, as well as guidelines for states to follow in developing plans to achieve the state-specific goals.

Among other things, the proposed emission guidelines establish state-specific interim and final CO_2 emission goals. The emission goals are expressed in the units of pounds of CO_2 emissions per net megawatt-hour (lb/MWh) of electricity produced. EPA arrives at the state-specific emission goals by applying a series of four "Building Blocks." Building Block 1 is to require an average heat rate improvement of 6 percent for each coal-fired electric generating unit (EGU) within the state. Specifically EPA states, "we propose to find that a six percent reduction in the CO_2 emission rate of the coal-fired EGUs in a state, on average, is a reasonable estimate of the amount of heat rate improvement that can be implemented at reasonable cost."[2]

That aspect of EPA's proposal is based on the Agency's assessment of historical heat rate data calculated from unit-level heat input and gross generation reported to EPA under 40 C.F.R. Part 75 (Part 75) for compliance with several market-based programs.[3] After supposedly filtering out data that may not represent actual heat rate improvements, EPA identified 16 EGUs (reference units) that purportedly reported a single year-to-year heat rate improvement of 3 to 8 percent.[4] Admitting that it was able to identify evidence of equipment upgrades in only two cases, EPA nonetheless asserts that equipment upgrades were the "most likely cause" of some of the other "observed" heat rate improvements

[1] 79 Fed. Reg., 34,830 (June 18, 2014).
[2] 79 Fed. Reg., 34,861 (June 18, 2014).
[3] EPA Technical Support Document, "GHG Abatement Measures," p. 2-17, Docket ID No. EPA-HQ-OAR-2013-0602, June 10, 2014 (GHG Abatement Document).
[4] *Id.* p. 2-32.

"based on the elimination of other possible explanations."[5] The remaining supposed improvements EPA attributes to "best practices."[6]

In a report titled "Critique of EPA's Use of Reference Units to Select Heat Rate Reduction Targets," ("Reference Unit Critique"), consultants working for the Utility Air Regulatory Group (UARG) summarized information they obtained from the owners of 14 of the 16 units regarding likely causes of the supposed heat rate improvements.[7] The report illustrated that most changes in heat rate calculated from the Part 75 reported data were due to unrelated normal variations in continuous emissions monitoring system (CEMS)-based heat input values, and not the result of proactive steps to reduce heat rate.

As a supplement to that report, UARG asked RMB Consulting & Research, Inc. (RMB) to review the summaries of the owners' explanations and more fully explain some of the sources of unrelated normal variability in reported Part 75 heat input data that could result in year-to-year changes in heat rates calculated from Part 75 data. RMB is eminently qualified to comment on CEMS technical issues because the RMB staff has been involved with the Part 75 CEMS requirements since their inception circa 1992. As discussed below, although the Part 75 data used by EPA meet stringent quality assurance criteria, all Part 75 CEMS measurements used to calculate heat input are subject to variability the cause of which may not be apparent when the data are viewed as annual averages. In addition, provisions in Part 75 that allow for, or require, adjustment of monitored data create inherent biases in the data that limit how the data can be used.

BACKGROUND

EGUs do not report "heat rate" to EPA. EPA's assessment of possible heat rate improvements is based on its calculation of a "heat rate" value based on the hourly heat input and gross generation data reported under Part 75. Because all of the causes identified by owners of the reference units attributed the apparent variability in heat rate to CEMS measurements (not the measurement of generation), this report focuses only on the measurement of heat input.

By far, the most frequently used equation for computing the heat input rates that electric utility companies report pursuant to Part 75 is as follows:[8]

$$\mathbf{HI = Q_w \frac{1}{F_c} \frac{\%\, CO_{2w}}{100}} \qquad \textbf{Equation 1}$$

Where:

HI = hourly heat input rate, mmBtu/hr

[5] *Id.*
[6] *Id.* p. 2-34; 79 Fed. Reg. 34,860.
[7] Prepared for UARG by J. Edward Cichanowicz and Michel C. Hien, Docket ID No. EPA-HQ-OAR-2013-0602 (Nov. 25, 2014).
[8] Part 75 also allows measurement of O_2 with a CEMS and conversion of that value to CO_2.

Q_w = hourly volumetric flow rate, wet basis, scfh
F_c = carbon-based F-factor, scf/mmBtu
CO_{2w} = hourly concentration of CO_2, wet basis, percent CO_2

Thus, reported hourly heat input rates are based on the determination of two critical parameters, volumetric flow rate and CO_2 concentration. Stack gas CO_2 concentrations are measured by means of CEMS. Volumetric flow rates are calculated by multiplying measured stack gas velocity times the cross-sectional area of the stack. Stack gas velocities are measured continuously in a stack using either of two measurement principles, ultrasonic flow or differential pressure.

ALLOWED MARGIN OF ERROR

All of the heat input data upon which EPA relied for its analysis are based on a series of measurements made with stack-installed instrumentation the performance of which is judged by how well they compare to EPA reference method measurements. Anyone with statistical training will attest to the following statement: all measurements are simply estimates of true values. Thus, all measurements are subject to error and uncertainty.

EPA's primary criterion for judging the acceptability of the performance of a CEMS (e.g., CO_2 monitor or flow monitor) is a metric called, "relative accuracy." Relative accuracy is determined by a relative accuracy test audit (RATA) during which EGUs conduct a minimum of nine measurements using one of the specified EPA reference methods and compare those results to the concurrent output from the installed CEMS using Equation 2.

$$\textbf{Relative Accuracy} = \frac{|\bar{\mathbf{d}}| + |\mathbf{CC}|}{\overline{\mathbf{RM}}} \qquad \textbf{Equation 2}$$

Where:

$|\bar{d}|$= absolute value of the mean difference between the reference method values and the corresponding CEMS values.
$[CC]$= absolute value of the confidence coefficient.
$\overline{RM}$= arithmetic mean of the reference method values.

The most restrictive Part 75 relative accuracy criterion is 7.5 percent. That is, if the relative accuracy of a CEMS is equal to or less than 7.5 percent, then relative accuracy testing is required annually.[9]

There are two important points to be made with respect to relative accuracy. First, the relative accuracy of the CEMS is determined by comparing the CEMS to EPA reference method measurements, which are conducted manually. Second, the CEMS and reference method agreement does not have to be exact; there is an allowable tolerance between the two sets of measurements. In this sense, the RATA establishes the allowed margin of

[9] If the CEMS relative accuracy is greater than 7.5 percent but less than 10 percent, then relative accuracy testing is required semi-annually.

error in the CEMS relative to the EPA test method, which itself is subject to variability. As long as the CEMS meets the relative accuracy criterion or allowed margin of error, its data are quality assured.

CEMS (CO_2 monitor or flow monitor) measurement variability that is within the allowed margin of error could account for some year-to-year variability in annual average heat input, even when no change has been made to the EGU or CEMS. However, as discussed more fully below, because EPA requires performance of a RATA following most significant changes to monitoring systems and flue gas handling systems,[10] changes with the potential to produce significant variations in measurements often are implemented just prior to the annual (or semi-annual) RATA.

ANNUAL FLOW MONITOR RECALIBRATION

Volumetric flow varies with load. To ensure that a flow monitor is meeting the allowed margin of error over the entire range of the EGU's operation, Part 75 generally requires that the RATA be performed at 3 load levels.[11] Software internal to the flow monitor includes K-factors or polynomial equations that ensure that the monitor produces a linear response over its full range. Any changes to these equations in turn trigger a requirement for a 3-load flow RATA to ensure that the monitor's accuracy has not fallen outside the allowable margin of error.

Because changes in those formulas are made in response to reference method data, the changes are often referred to as a flow monitor "recalibration." Annual flow monitor "recalibrations" at the time of the regular 3-load RATA are not uncommon. Changes to these equations may be made in response to failure of the relative accuracy criterion at one or more loads, or simply in an attempt to increase the accuracy of the monitor. In any event, these "recalibrations" can result in changes in volumetric flow measurements that create annual variability in heat input measurements.

PHYSICAL CHANGES IN THE FLUE GAS HANDLING SYSTEM

Changes in an EGU's flue gas handling system (i.e., duct work, fans, or stack) also can significantly affect flow measurements. Stacks or ducts with certain physical characteristics can cause the flue gas to swirl (i.e., have non-axial components) rather than traveling straight up the stack. Some EPA reference methods (including the original Method 2) do not distinguish between straight and non-axial flow.

Stack volumetric flow also is affected by friction along the walls of the stack or duct that causes flow to decrease (i.e., velocity decay) near the stack wall. Reference method velocity measurements are taken at the centroid of several equal area segments within the cross-section of the stack. EPA's velocity reference method assumes the flow determined at the measurement point is equal across the entire width of the equal area segment. This assumption is not correct for the measurement segment that is adjacent to

[10] *See, e.g.*, 40 C.F.R. § 75.20(b).
[11] *See, e.g.*, 40 C.F.R. Part 75, App. A. § 6.5.2.

the stack wall, because the stack gas velocity actually decays to zero at the wall. Thus, the EPA reference method procedure for measuring volumetric flow yields results that are naturally biased high. The amount of bias can vary based on the stack liner material (e.g., masonry causes more friction than steel) and the shape of the stack flue or duct (e.g., rectangular, square, or circular).

Because of these effects, any change in the flue gas handling system that could create or reduce swirling flow (e.g., the reworking of ducts, addition of straightening veins, or removal of a unit from a common stack) or that changes the shape or liner of a duct or stack can have a significant effect on flow measurements. Although such changes are not made frequently, they often are made in concert with addition of new pollution controls.

EPA in 1999 promulgated new flow methods that are capable of correcting for non-axial flow and wall effects. As discussed below, a change in the flow method used to conduct the RATA can result for some EGUs (i.e., those with non-axial flow or significant wall effects) in a significant change in heat input. However, similar changes can occur without a change in flow method if the flue gas handling system itself is changed.

CHANGES IN STACK DIAMETER MEASUREMENT

Volumetric flow is calculated by multiplying measured stack gas velocity times the stack area. Of course, stack area is calculated from knowing or measuring the stack diameter. However, measuring the diameter of a 25-foot smoke stack accurately is a challenge in and of itself. Regardless of the measurement technology used, an error in determining the cross-sectional area of a stack of 1 to 2 percent is not at all uncommon. Periodic changes in measurements can result in changes in measured volumetric flow and reported heat input.

CHANGES IN MONITORING TECHNOLOGY

There are two primary technologies used to monitor flow under Part 75 – differential pressure and ultrasonic. Part 75 allows use of either technology, and allows EGUs to change monitoring systems or technology, as long as the monitor employed meets the relative accuracy criterion (and any other applicable quality assurance tests). Although EGUs do not change monitor or monitoring technology frequently, if they do it would not be unusual for that change to result in a change in the flow measurement and therefore the reported heat input.

COMMON STACK MONITORING

Although Part 75 requires reporting of heat input on a unit-specific basis,[12] it does not require separate monitoring of heat input for each unit. The data handling procedures for common stack configurations are addressed specifically in 40 C.F.R. 75.16(e).

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[12] 40 C.F.R. § 75.57(b)(5).

> The owner or operator of an affected unit with a diluent monitor and a flow monitor installed on a common stack to determine heat input rate at the common stack may choose to apportion the heat input rate from the common stack to each affected unit utilizing the common stack by using either of the following two methods, provided that all of the units utilizing the common stack are combusting fuel with the same F-factor found in section 3 of appendix F of this part. The heat input rate may be apportioned either by using the ratio of load (in MWe) for each individual unit to the total load for all units utilizing the common stack or by using the ratio of steam load (in 1000 lb/hr or mmBtu/hr thermal output) for each individual unit to the total steam load for all units utilizing the common stack, in conjunction with the appropriate unit and stack operating times.

When heat input rate is apportioned among common stack units based on load (either electrical or steam), the underlying assumption is that the individual heat rates of the affected units are equal. Yet Part 75 allows such an apportionment for any common stack configuration regardless of actual heat rate. Thus, attempting to make any inferences about heat rates for units with common stacks is meaningless.

This limitation applies to several of the 16 reference units in EPA's study, including Colbert 1, 2 and 3, which are owned and operated by the Tennessee Valley Authority (TVA).

CHANGES IN BIAS ADJUSTMENT FACTORS

As part of relative accuracy testing, Part 75 requires the performance of a bias test and the application of a bias adjustment factor (BAF) when a bias test is failed. With reference to Equation 2 above, a bias test is failed if $|\bar{d}| > \lceil CC \rceil$. When a bias test is failed, the BAF is calculated according to the following equation.

$$\mathbf{BAF = 1 + \frac{|\bar{d}|}{CEM_{avg}}} \qquad \textbf{Equation 3}$$

Where:

CEM_{avg} = Mean of the monitor values provided by the CEMS during the failed bias test.

The BAF is applied according to the following equation.[13]

$$\boldsymbol{CEM^{adjusted} = CEM^{monitor} \times BAF} \qquad \textbf{Equation 4}$$

Where:

$CEM^{monitor}$ = Raw data value provided by the monitor.
$CEM^{adjusted}$ = Data value adjusted for CEMS bias.

[13] Part 75 regulations do not require the use of BAFs on CO_2 concentration measurements; however, volumetric flow measurements are subject to BAF requirements.

Part 75 regulations cap the BAF at the lesser of the value calculated from Equation 4 or 1.111. In practice, most BAFs observed by RMB are in the 1 to 5 percent range. The reason for presenting the BAF discussion is to present another example of how CEMS responses can exhibit step changes of several percent completely independently of any change in heat rate or CO_2 emission rate. In EPA's discussion of its EGU study population of 884 EGUs, the Agency acknowledges the data substitution procedures imposed by Part 75 and how these procedures are designed to overestimate emissions.[14] However, EPA does not mention how BAFs or how BAF-adjusted data were treated in its study/analysis. In the absence of even the acknowledgement of BAF-adjusted data, we believe it is reasonable to assume that EPA's analysis failed to account for such data. Changing, adding or deleting BAFs will clearly cause CEMS data to exhibit step changes; there is no evidence that the EPA analysis accounted for BAF-adjusted Part 75 data.

CHANGES IN FLOW METHODS USED FOR CALIBRATION

By far the most challenging component of accurate volumetric flow determination is the measurement of stack gas velocity. Velocity is a vector component not a gaseous constituent like CO_2. The challenge is to accurately measure the speed with which the gas is traveling up the stack. Determining the relative accuracy of the flow monitor presents an interesting challenge because there are at least three different EPA reference methods than can be used – EPA Methods 2, 2F and 2G.

As discussed above, the physical characteristics of flue gas handling systems can have a significant impact on flow measurements. In its GHG Abatement Document, EPA discusses the optional flow reference methods the Agency adopted to allow owners to correct for the high biases that can be created by non-axial flow and wall effects at some EGUs. EPA estimated that "approximately two thirds of the large decreases in heat rate" in its study population of 355 units can be associated with changes in the flow method used to conduct the annual RATA.[15] Although EPA claims that it screened for such reporting changes when it selected the 16 reference units, several owners report significant reductions in heat input associated with a change in flow methods.[16]

The following case study illustrates the dramatic impact a change in method can have on hourly heat input. Two graphs are attached of a project completed a couple of years ago by RMB. RMB titles such projects "heat rate discrepancy" studies. The title emanates from the fact that a plant is observing one heat rate based on its fuel data and a different (usually higher) heat rate based on its Part 75 CEMS data. Based upon the analytical approach described in the previously referenced GHG Abatement Document and the data presented in the attached graphs, EPA would likely conclude that significant heat rate improvement projects had been conducted. To the contrary, RMB assisted the plant in (1) performing a more accurate reference method testing to determine the volumetric

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[14] *Id*., p. 2-17.
[15] GHG Abatement Document, p. 2-29 and footnote 22.
[16] *See, e.g.*, Reference Unit Critique pp. 6, 14 and 21.

flow (i.e., EPA Method 2F instead of Method 2) and recalibrating the two stack flow monitors based on the more accurate reference method data, and (2) implementing the wall effects correction factor (Method 2H). There was no change in the heat rate of either unit.

How EPA missed the impact of such changes in its "screening" process is difficult to understand. It might be argued that RMB possessed "inside" information regarding the case study presented above; information above and beyond what an EPA analysis could have reasonably obtained. We disagree for the following reasons. First, if the significant decrease in CO_2 emission rate depicted on the attached graphs were the result of heat rate improvement projects, you would have expected the decrease to occur after the unit had been off line (to allow the heat rate project to be conducted). Clearly, this was not the case. Second, EPA could have easily verified whether the change in CO_2 emission rate was the result of a recent relative accuracy test. The relative accuracy test audit (RATA) data are readily available using EPA's Emission Collection and Monitoring System (ECMPS) software. The following important information is available from a RATA report.

- Test method used (e.g., Method 2, 2F, or 2G)
- Number of loads for which a flow RATA was conducted
- Bias adjustment factor (BAF) required, if any.
- Wall-effects adjustment factor (WAF) (whether default value or calculated).

In short, depending upon the flow pattern that exists within the stack, application of any one of the three acceptable EPA reference methods can yield results that vary from one of the other EPA reference methods by several percent. The calibration of a flow monitor can easily change following a relative accuracy test -- if an EGU owner/operator has elected to change from one EPA reference method (e.g., Method 2) to another (e.g., Method 2G).

SUMMARY

EPA's calculation of heat rate requires knowledge of heat input. Heat input is calculated and reported under Part 75 using CEMS (usually from measurements made with a CO_2 monitor, and a flow monitor). In RMB's experience, the determination of accurate volumetric stack flow rates is the most challenging. All measurements have inherent error and uncertainty, and any one of the above factors can result in significant year-to-year variability in measurements.

EPA's claim that it eliminated other possible explanations for the calculated heat rate improvements in its 16 reference units is both unsubstantiated, and directly contradicted by the very real sources of variability identified by the units' owners and the information they report to Part 75. Had EPA gone to the effort to review relevant information in those reports, or acknowledged the very real and obvious sources of normal variability in the Part 75 heat input measurements, EPA would have realized that its analysis supporting a 6 percent heat rate improvement is not defensible. In reality, EPA's analysis is quantifying nothing more than measurement variability. EPA's analysis is not measuring a real change in heat rate and certainly not an improvement in heat rate.

Attachment

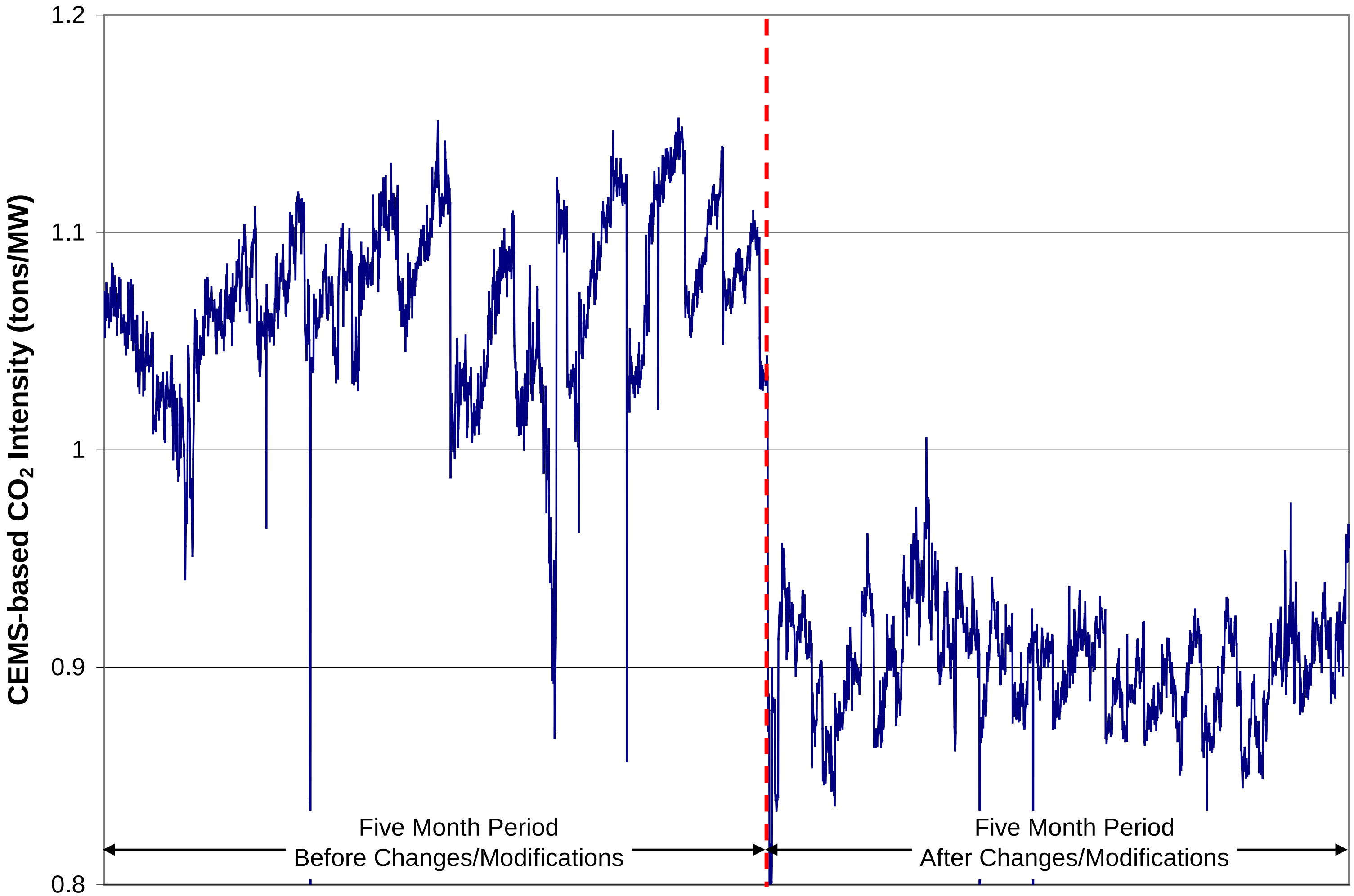

Figure 1. Unit 1, Before and After Flow Monitor Adjustment

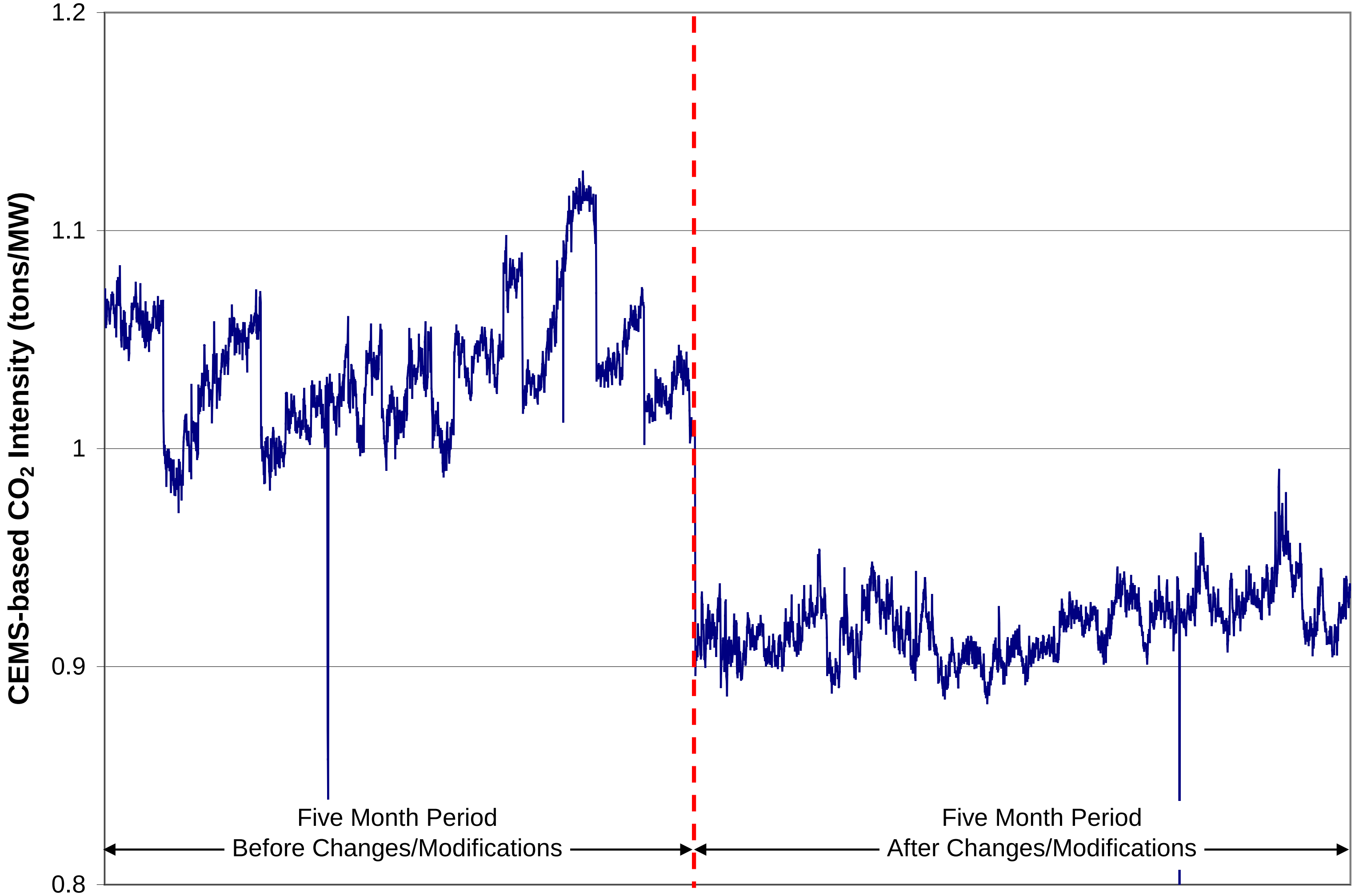

Figure 2. Unit 2, Before and After Flow Monitor Adjustment