A photograph of an industrial facility, likely a refinery or chemical plant, silhouetted against a bright, golden sunset sky. The scene features several tall distillation columns and complex piping structures. The lighting is dramatic, with the sun low on the horizon, creating a strong glow and long shadows.

Siemens Total Solution for Greenhouse Gas (GHG) Emissions from Fuel Gas

40 CFR Part 98

MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

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SIEMENS

Regulation Intent

On September 22, 2009, the EPA promulgated a new rule affecting GHG emissions from numerous industries. Implementation took effect on Jan 1, 2010, with the first reporting year being March, 2011 (reporting 2010 data). Targeted emission components are CO₂, CH₄, NO (N₂O), Fluorinated HC, and SF₆. Facilities will report total annual GHG emissions in metric tons CO₂e and separately present annual mass emissions of each individual GHG for each source category at the facility.

According to the EPA, global atmospheric CO₂ concentration increased ~ 35 % from the pre-industrial era to 2005. The global atmospheric concentration of CH₄ has increased by 148 % from pre-industrial levels, and the N₂O concentration has increased 18 %. CO₂ is the largest contributor to GHG concentrations followed by CH₄. HFCs, PFCs, SF₆, etc. are relatively low but are increasing rapidly, and are entirely anthropogenic in origin. Fossil fuels are the largest source of GHG emissions in the U.S. and accounts for ~ 80 % of total, according to EPA figures.

The Intergovernmental Panel on Climate Change (IPCC) defined the term "Global Warming Potential" (GWP) which includes a greenhouse gas's heat-trapping ability as well as its atmospheric lifetime. CO₂ was given the value of 1.0 CO₂e (equivalents), with CH₄ equal to 21 CO₂e and SF₆ equal to 23,900 CO₂e. EPA estimated total U.S. GHG emissions were 7,054 million metric tons of CO₂e in 2006, and overall emissions have grown by 15 % from 1990 to 2006.

Reporting System

EPA identified the following goals of the mandatory reporting system:

- Obtain data that is of sufficient quality that it can be used to support a range of future climate change policies and regulations.
- Create reporting requirements consistent with existing GHG reporting programs by using existing GHG emission estimation and reporting methodologies to reduce reporting burden, where feasible.

EPA claims to have built upon concepts in existing Federal and State programs in developing the mandatory GHG reporting rule, e.g. California Mandatory GHG Reporting Rule (CARB) and 40 CFR part 75.

Schedule and Reporting

The new Rule requires the submission of GHG emissions data on an ongoing, annual basis. The annual report is to include total annual GHG emissions. Sites are to separately present annual mass GHG emissions for each source category and supply category, by gas. Additionally, sites are to report data for each individual unit in the case of some source categories and for each process line for other source categories. Reports should also include certain activity data (e.g., fuel use, feedstock inputs) used to generate the emissions data, according to the Regulation.

EPA established the requirement of annual reporting of GHG by the following categories of sources:

- 25 source categories
- 5 types of suppliers of fuel and industrial GHG
- Motor vehicle and engine suppliers (except light duty sector)

Reporting will be via direct, electronic submission to EPA, and verification of emissions data will be managed by EPA, as opposed to a third party.

Facility Assessment of Applicability

EPA defined a facility as:

- Physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties
- In actual physical contact or separated solely by public roadway or other public right of way
- Under common ownership or common control
- Emits or may emit GHGs
- Military installations may be classified as more than one facility.

A facility can have multiple source categories, and must evaluate each source category separately to assess applicability to the rule. Facilities which have an "all-in" source category within their boundaries are subject to the rule, and facilities must aggregate these categories to meet the 25,000 metric tons CO₂e per year reporting threshold. If the rule applies, facilities are to report emissions for all source categories for which methods are provided in the rule.

Special Provisions for Reporting Year 2010

EPA provided special provisions for the year 2010. From January 1 - March 31, 2010, sources may use "best available monitoring methods" for any parameter that can not reasonably be measured according to the monitoring and QA/QC requirements of the rule. Not reasonably feasible is defined as: "unable to acquire, install, and operate a required piece of monitoring equipment by Jan 1, 2010" (1). Best available monitoring methods include:

- Monitoring methods currently used by the facility that do not meet the specifications of a relevant subpart
- Supplier data
- Engineering calculations
- Other company data

However, each reporter must still use the calculation methodologies and equations of each relevant subpart. Beginning April 1, 2010, reporters must begin following all applicable monitoring and QA/QC requirements. (Note: most reporters expect this date will be relaxed in order to accommodate current status of sites). Additionally, reporters can submit an extension request to EPA showing that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by April 1, 2010. However, extension requests must be submitted no later than January 28, 2010. EPA stated that it would be "highly unlikely we would approve extension requests for parameters that are measured by periodic sampling and analyses". (i.e. "collect periodic samples and send them off-site for analyses") (1). EPA will not approve use of best available methods beyond December 31, 2010. Also, EPA determined that extensions for design of electronic recordkeeping systems will not be approved.

GHG Emissions from Petroleum Refineries

Refinery Sources Affected

EPA defined petroleum refineries as facilities that produce gasoline, gasoline blending stocks, naphtha, kerosene, distillate fuel oils, residual fuel oils, lubricants, or asphalt (bitumen) by the distillation of petroleum or the redistillation, cracking, or reforming of unfinished petroleum derivatives. Emissions from petroleum refineries account for approximately 205 million metric tons CO₂e, representing approximately 3 percent of the U.S. nationwide GHG emissions. Most of these emissions are CO₂ emissions from fossil fuel combustion, accounting for approximately 67 percent of CO₂ emissions at a refinery. EPA proposes that all petroleum refineries should report. Based on the emission sources at petroleum refineries, GHGs to report are limited to CO₂, CH₄, and N₂O.



Summary Petroleum Refinery Sources for GHG				
Subpart Y—Petroleum Refineries	CO ₂	CH ₄	N ₂ O	Measurement Frequency
Stationary Combustion	HHV or CC	calc	calc	Weekly; calc if no CEMS; Tier 4 methodology
Stationary Combustion using Fuel Gas	Tier 3 or 4	√	√	
Flares	HHV or CC	calc	calc	Daily or weekly; calc if no CEMS
Catalytic cracking units	CEMS (CO ₂ , O ₂ , CO) or CC	calc	calc	>10K bbls/sd ≤ hourly Monitor O ₂ , CO ₂ , CO; <10K bbls/sd 1) ≤ daily Monitor O ₂ , CO ₂ , CO 2) Calc CO ₂ from ea CCU and FCU using factor & CC of coke (measured or default value)
Traditional Fluid coking unit	CEMS (CO ₂ , O ₂ , CO) or CC	calc	calc	1) Monitor ≤ daily O ₂ , CO ₂ , 2) Calc CO ₂ via CC (measurement or default value)
Fluid coking units with flexi-coking design	CEMS (CO ₂ , O ₂ , CO) or CC	calc	calc	>10K bbls/sd ≤ hourly Monitor O ₂ , CO ₂ , CO; <10K bbls/sd 1) ≤ daily Monitor O ₂ , CO ₂ , CO 2) Calc CO ₂ from ea CCU and FCU using factor & CC of coke (measured or default value)
Catalytic reforming units	CEMS (CO ₂ , O ₂ , CO) or CC	calc	calc	1) Monitor ≤ daily O ₂ , CO ₂ , 2) Calc CO ₂ via CC (measurement or default value)
On-site and off-site sulfur recovery	CEMS or Calc			CC of sour gas stream (measurement or default value).
Coke calcining units	CEMS	calc	calc	CO ₂ difference between carbon input as green coke and carbon output as marketable petroleum coke, and as coke dust collected dust collection system.
Asphalt blowing operations	Calc	calc		Uncontrolled - CO ₂ & CH ₄ facility-specific emission factors based on test data or default. Controlled - CH ₄ & CO ₂ calc.
Equipment Leaks		calc		calculated using either default emission factors or process-specific CH ₄ comp data & leak data
Storage tanks		CEMS		Numerous stipulations
Delayed coking units		calc		
Other Process vents	calc	calc	calc	Calc using vol flow rate & mole fraction GHG
Uncontrolled blowdown systems		calc		Calc mass balance method or default factor
Loading operation		calc		
Hydrogen plants (non-merchant)	√	√	√	Refer to Subpart C and P

GHG Emission Calculations

CO₂ emissions must use one of two alternative methods:

For refinery units with continuous emission monitoring systems (CEMS) in place, reporters can elect to either:

- 1) For applicable processes, refinery units with certain types of continuous emission monitoring systems (CEMS) in place must report using the CEMS
- 2) Follow the Tier 4 methodology of 40 CFR part 98, subpart C to report combined process and combustion CO₂ emissions.

For refinery units without CEMS in place, reporters can elect to either:

- 1) Install and operate a CEMS to measure combined process and combustion CO₂ emissions according to the requirements specified in 40 CFR part 98, subpart C; or
- 2) Calculate CO₂ emissions using the methods summarized in the Regulation.

General Stationary Fuel Combustion Sources (GHG Regulation Part 98 Subpart C)

Source Category Definition

Within the GHG regulation, EPA chose to define unique requirements for Stationary Fuel Combustion sources. This resulted in a class of “general” sources, with applicability not limited to any certain industries or products. The source is defined as:

Devices that combust any solid, liquid, or gaseous fuel generally to:

- Produce electricity, steam, useful heat, or energy for industrial, commercial, or institutional use
- Reduce the volume of waste by removing combustible matter.
- Devices include, but are not limited to, boilers, combustion turbines, engines, incinerators, and process heaters.

Stationary combustion sources exclude flares, which are covered within the section for petroleum refineries.

EPA’s Tier Calculation Methodology for Stationary Combustion Units

EPA identified the following components to be reported from stationary combustion units:

- Annual CO₂, CH₄ and N₂O emissions from each fuel combustion unit.
- For each unit, CO₂, CH₄, and N₂O emissions must be reported separately for each type of fuel combusted, including biomass fuels.

As part of the GHG regulation for stationary combustion units, EPA defined a 4-tier methodology for determination of reporting and monitoring requirements. Generally, annual fuel use can be determined either by use of company records (e.g., billing data, steam generation, unit operating hours) or by direct measurement using flow meters, depending on the size of the unit and the type of fuel burned. Depending on the tier calculation method used

and the fuel burned, reporters could be required to determine high heating value, molecular weight, or carbon content of fuel. Fuel sampling and analysis must be conducted daily, weekly, monthly, quarterly, semi-annually, or by lot, depending on the type of fuel burned. Most refineries will fall under the Tier 3 or 4 categories.

Tier 3 Calculation Methodology

According to the regulation, Tier 3 uses calculations based on annual fuel use and measured carbon content of that fuel, and is further described by:

- Calculate emissions only for fuels that contribute 10 percent or more of the annual heat input to the unit.
- Used for maximum rated heat input capacity of greater than 250 mmBtu/hr that combusts any type of fuel listed in the regulation (except Municipal Solid Waste), unless either of the following conditions apply:
 - Use of Tier 1 or 2 is permitted.
 - Use of Tier 4 is required.
- Should be used for a fuel not listed in regulation

Tier 3 calculation methodologies require periodic measurements of fuel heating value and carbon content. The rule allows use of several identified standard methods to determine the high heat values. As an option for gaseous fuels, “the HHV may be calculated using chromatographic analysis together with standard heating values of the fuel constituents, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer’s instructions”.

Analysis frequency for refinery gas requires daily sampling and analysis to determine carbon content and molecular weight of the fuel is required if the necessary equipment is in place to make these measurements. Otherwise, weekly sampling and analysis.

Tier 4 Calculation Methodology

According to the regulation, Tier 4 has the following stipulations:

- Requires use of continuous emission monitoring systems (CEMS)
- Units that have certain types of existing CEMS in place and meet specific criteria are required to use the Tier 4. In some situations, the rule could require upgrades to existing CEMS in order to comply with Tier 4. Upgrades depend on fuel burned and CEMS currently installed.
- Combustion units subject to reporting requirements under EPA’s Acid Rain Program will continue to measure CO₂ mass emissions using 40 CFR part 75 methods; reporters must report CO₂ emissions by converting cumulative fourth quarter CO₂ emissions from short tons to metric tons.
- Applies to units of any size and any type of fuel
- Reporters are required to calculate GHG emissions only for specific fuels listed in rule, except units greater than 250 mmBtu/hr in which case reporters are required to calculate GHG emissions for any fuel that provides 10 percent or more of the annual heat input to the unit.
- Tier 4 is used if the unit meets all six of the conditions below:
 - Max rated heat input capacity greater than 250 mmBtu/hr, or if unit combusts municipal solid waste and has a maximum rated input capacity of greater than 250 tons per day of MSW
 - Combusts solid fossil fuel or MSW, either as a primary or secondary fuel.

- Unit has operated for greater than 1,000 hours in any calendar year since 2005.
- Unit has installed CEMS required by applicable Federal or State regulation or the unit's operating permit. Installed CEMS include gas monitor of any kind or a stack gas volumetric flow rate monitor, or both and monitors have been certified. Installed gas or stack gas volumetric flow rate monitors are required to undergo periodic quality assurance testing in accordance with an existing regulation.

Flares

For refinery flares, the regulation provides that CO₂ emissions are to be calculated using the gas flow rate (measured with a

continuous flow meter or estimated using engineering calculations) and either:

- 1) Daily or weekly measured carbon content of the flare gas; or
- 2) Daily or weekly measured heat content of the flare gas and a default emission factor provided in the rule.

According to the regulation, if the carbon content and heat content of the gas are not measured at least weekly, engineering estimates of heat content during normal flare use may be used, but CO₂ emissions from each startup, shutdown, and malfunction event exceeding a certain threshold must be calculated separately, also using engineering estimates. CH₄ and N₂O emissions are calculated using stationary combustion (subpart C) rules.

Siemens Solutions

Reporters which fall under Tier 3 or 4, and elect to measure Fuel Gas sources, will need to measure BTU / HHV along with Carbon Content for reporting purposes. Reporters will also need to measure the flow rate of the Fuel Gas and then do the CO₂ Equivalency calculation in the DCS or DAS. Siemens provides a Process Gas Chromatograph solution that can be mounted in a Cabinet or Walk-in Shelter depending on customer requirements.



Maxum Process Gas Chromatograph



Shelter with MAXUM



Cabinet with MicroSAM



Shelter



ULTRAMAT 6

If a reporter elects to not measure BTU and Carbon Content, then you will need to measure CO₂ in each stack along with the stack flow rates. If you choose this design, Siemens has a solution that uses our ULTRAMAT 6 IR Analyzer to measure CO₂. This analyzer can be added to an existing CEMS or be a stand-alone system with Sample Conditioning System installed in a Cabinet or Walk In Shelter depending on customer requirements.

Determination of HHV and Carbon Content using the Siemens Maxum ed II On-Line Process Gas Chromatograph

For much of the GHG regulation, EPA provided some amount of latitude regarding analytical methodologies to be used. For example, for Refinery sources, gas composition and heating value monitors may be calibrated according to the procedures in the applicable methods within the regulation or procedures specified by the manufacturer. Flare gas composition and high heating value may be determined by following one of several standard methods identified in the regulation.

Siemens solution entails a chromatography method similar to D3588 but with some variances. (These variances will need to be addressed in a Reporter's QAP.) The HHV is calculated using chromatographic analysis together with standard heating values of the fuel constituents. The gas chromatograph is to be operated, maintained, and calibrated according to the manufacturer's instructions.

CH₄ or N₂O emissions are calculated using Equation C-10a (from the GHG publication):

$$CH_4 \text{ or } N_2O = \sum_{p=1}^n 1 \times 10^{-3} * (Fuel)_p * (HHV)_p * EF \quad (\text{Eq. C-10a})$$

Where:

CH₄ or N₂O = Annual CH₄ or N₂O emissions from the combustion of a particular type of fuel (metric tons)

n = Number of required heat content measurements for the year

p = Measurement period (day or month, as applicable)

1 x 10⁻³ = Conversion factor from kilograms to metric tons

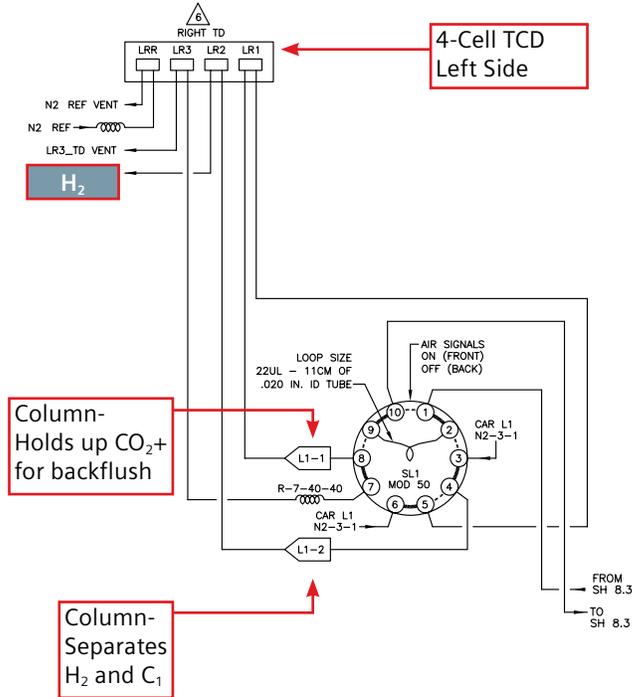
(Fuel)_p = Mass or volume of the fuel combusted during the measurement period "p"
(mass or volume per unit time)

(HHV)_p = Measured high heat value of the fuel for period "p" (mmBtu per mass or volume)

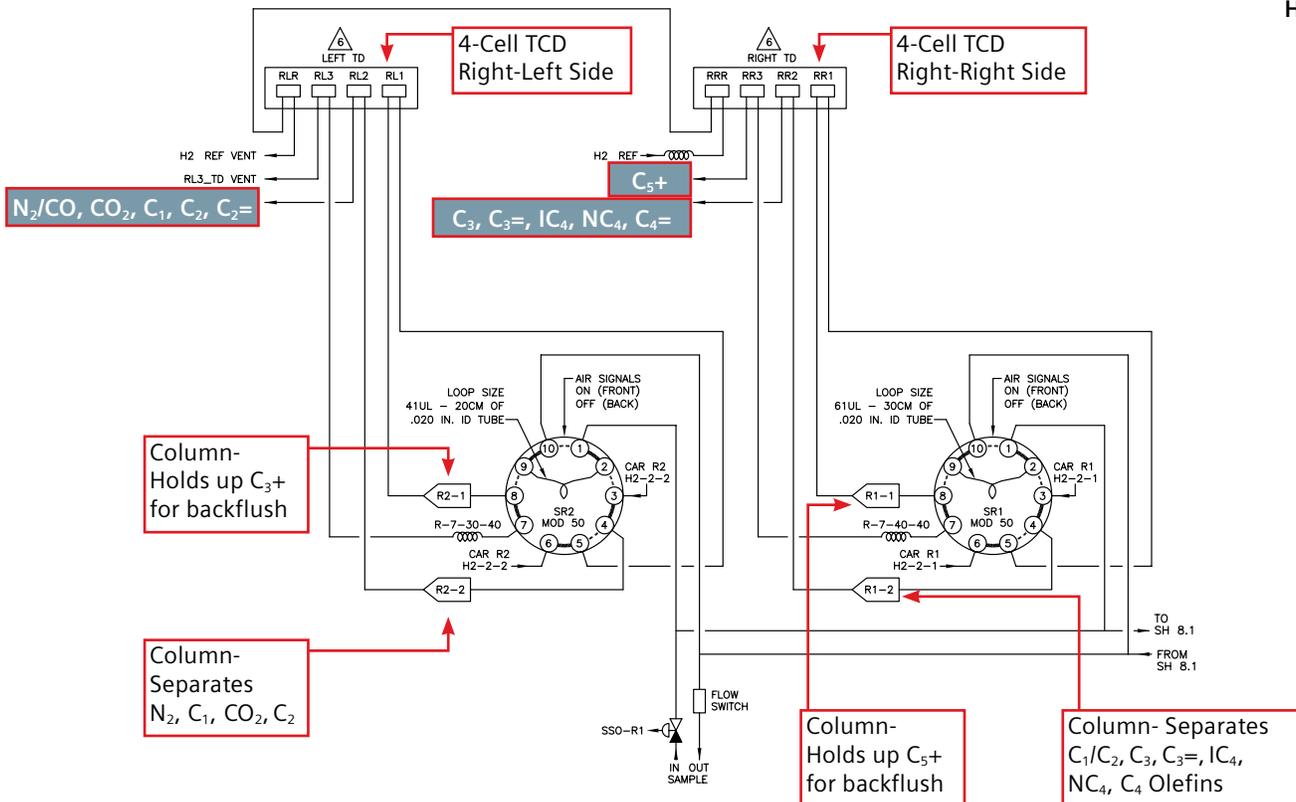
EF = Fuel-specific default emission factor for CH₄ or N₂O, from Table C-3 of this subpart
(kg CH₄ or N₂O per mmBtu)

A large US refinery had a requirement for determination of HHV and Carbon Content in fuel gas. The following are application details using the Siemens Maxum ed II Process Gas Chromatograph and a dual oven arrangement.

**Left Oven Plumbing Diagram –
Backflush to Vent
H₂ Measurement
N₂ Carrier**



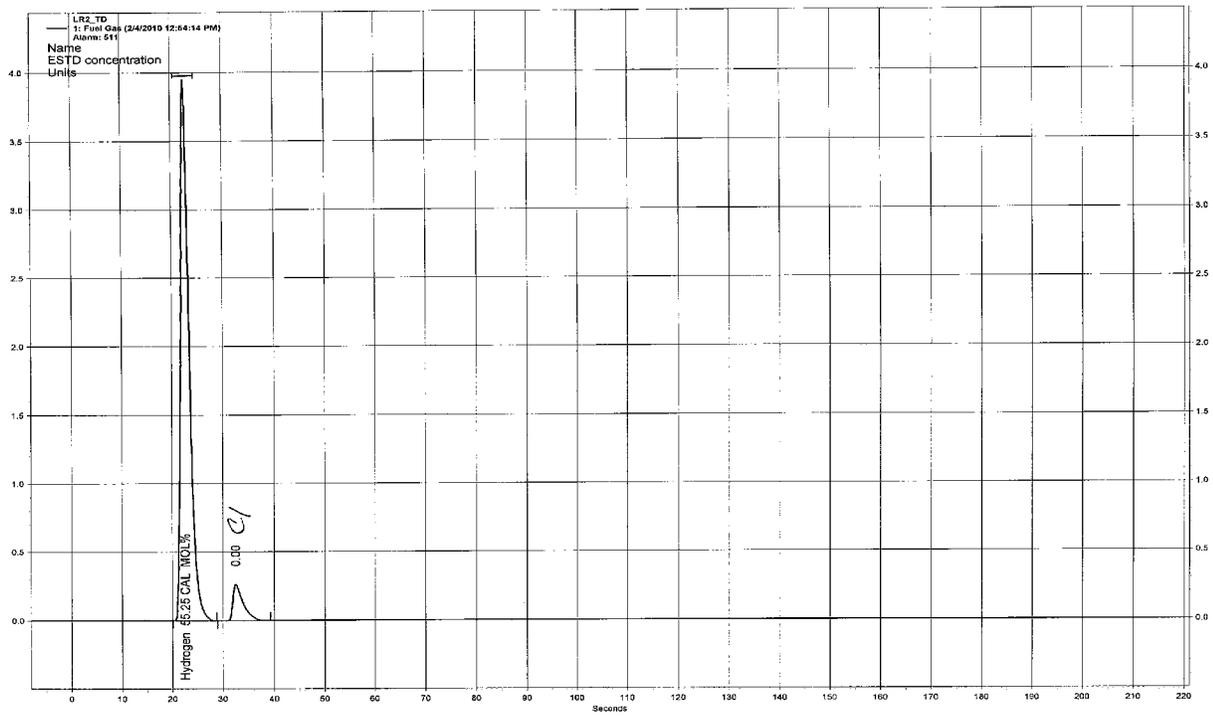
**Right Oven Plumbing Diagram
Backflush to Vent w/com Ref
H₂ Carrier**



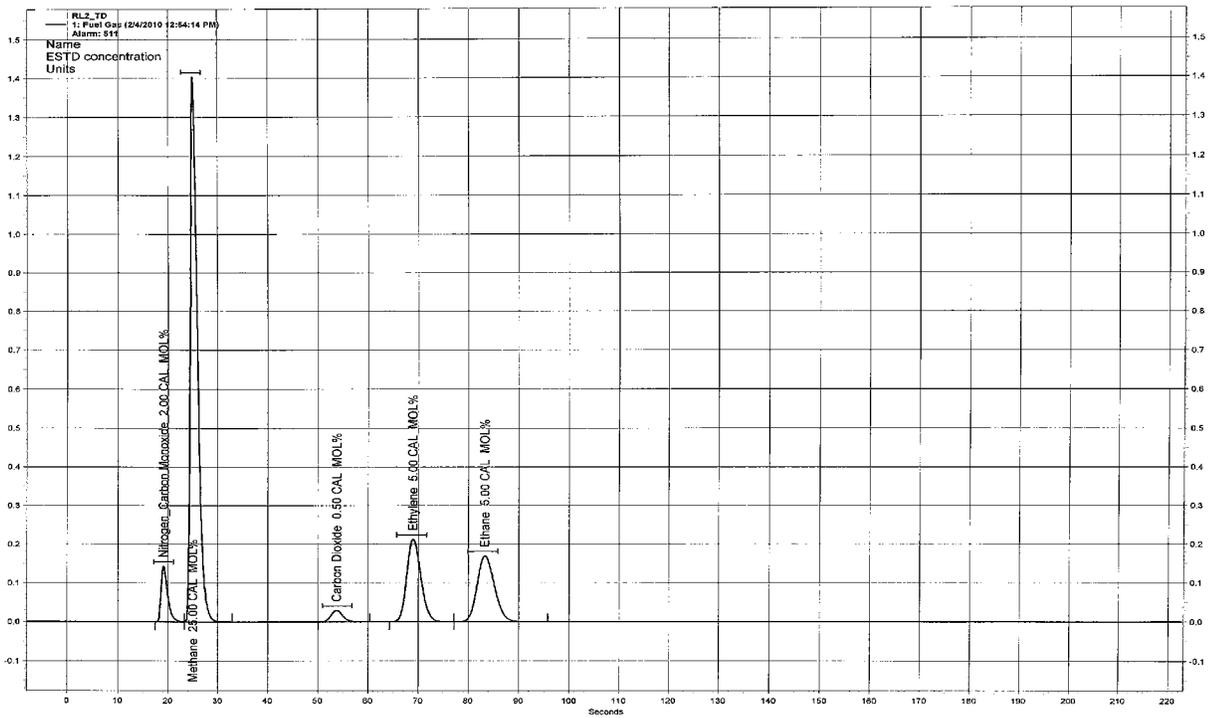
Stream Compositions – Cycle Time 240 seconds

Fuel Gas					
Component	Concentration		Units	Repeatability (% Full Scale)	Detector
	Normal	Range			
H ₂	49.5	0-100	Mol %	0.5	LR2_TD
N ₂ /CO	1.9	0-5	Mol %	0.5	RL2_TD
CO ₂	0.15	0-1	Mol %	1	RL2_TD
CH ₄	23.5	0-50	Mol %	0.5	
Ethane	14	0-30	Mol %	0.5	
Ethylene	4.3	0-10	Mol %	0.5	
Propane	2.7	0-10	Mol %	0.5	RR2_TD
Propylene	1	0-5	Mol %	0.5	
Isobutane	0.6	0-2	Mol %	0.5	
n-Butane	0.6	0-2	Mol %	0.5	
C ₄ Olefins	1.2	0-5	Mol %	1	
C ₅ +	0.92	0-2	Mol %	1	
H ₂ S	150		PPMV		
Gross BTU	910	800-1200	BTU		CALC
Specific Gravity	0.4997	0-0.7			CALC
Total Carbon		0-100			CALC
Un-Normalized Total					CALC
Net BTU					CALC

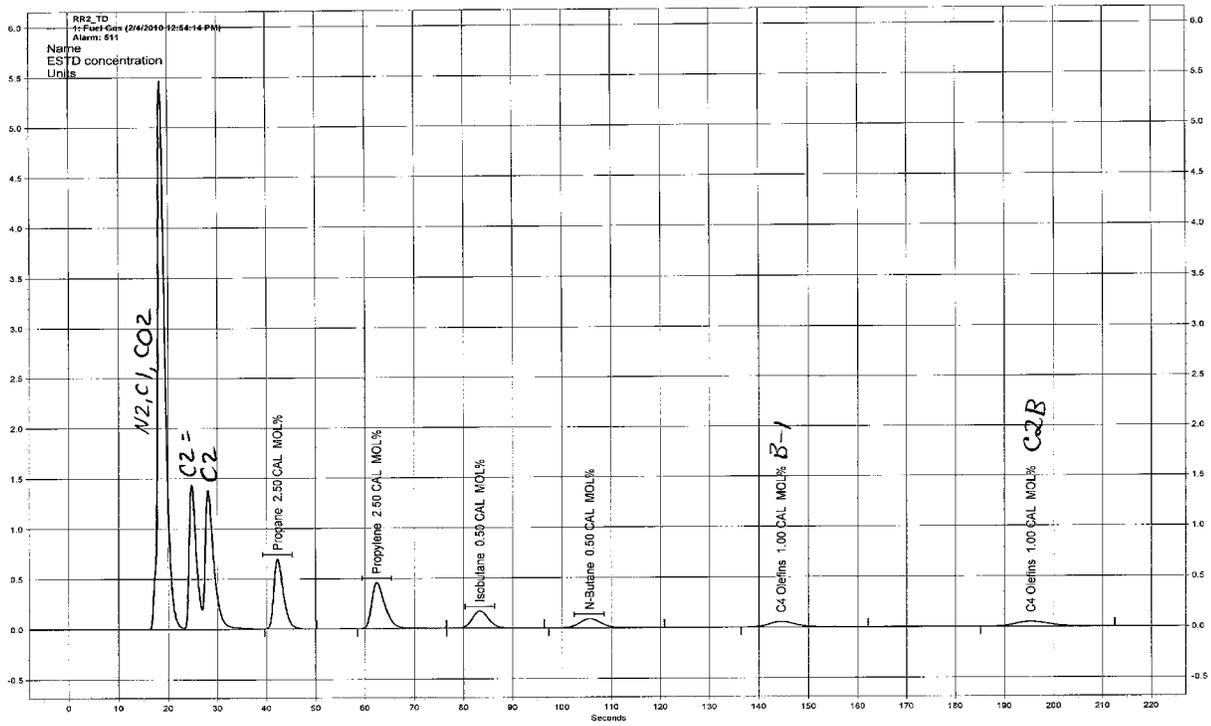
Hydrogen peak from detector LR2_TD



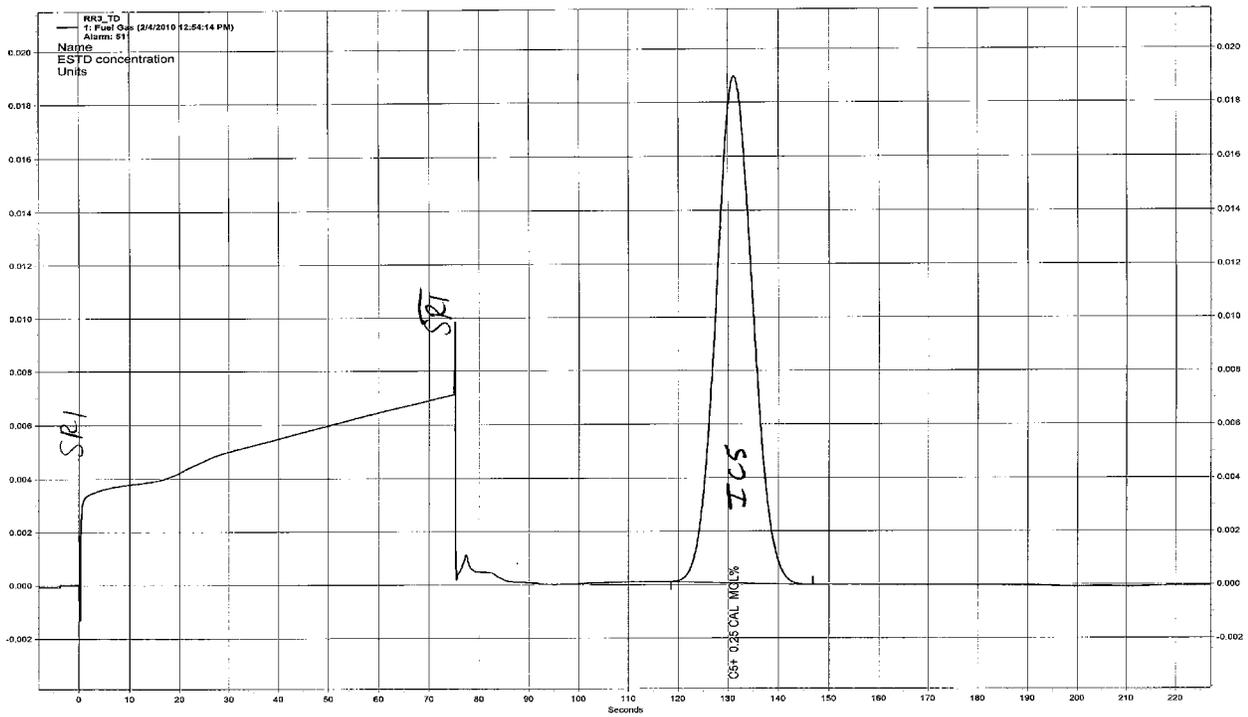
Nitrogen, Methane, Carbon Dioxide, Ethylene, Ethane peaks from detector RL2_TD



Nitrogen/Methane/CO₂, Ethylene, Ethane, Propane, Propylene, Isobutane, n-Butane, C₄ Olefins peaks from detector RR2_TD



IC₅ peak from detector RR3_TD



Notes:

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