Petroleum and Natural Gas Systems Emissions Reporting Guidance
for California's Mandatory Greenhouse Gas Reporting Regulation

This document describes the requirements for facility operators of petroleum and natural gas systems for reporting greenhouse gas (GHG) emissions data under the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (title 17, California Code of Regulations, section 95100 *et seq*) (MRR).

The petroleum and natural gas systems sector consists of eight industry segments as defined in section 95150 of MRR. This guidance document does not, and cannot, create or vary any legal requirements of MRR.

This document discusses how facility definitions are applied to each industry segment, describes updated reporting requirements that became effective January 1, 2015, and provides answers to frequently asked questions from this sector.

This guidance does not discuss reporting requirements related to covered product data. For additional information about covered product data reporting for petroleum and natural gas systems see the Petroleum and Natural Gas Systems Covered Product Data Reporting and Verification Guidance document.

1 Identifying and Defining Facility Industry Segments

Section 95101(e) of MRR includes eight industry segments for petroleum and natural gas systems. Of these segments, two industry segments—natural gas distribution, and onshore petroleum and natural gas production—have specific, more specialized "facility" definitions within MRR. All other industry segments use the definition of "facility" in section 95102(a)(170) of MRR.

1.1 Natural Gas Distribution Facility Definition

Section 95102(a)(171) of MRR includes a specialized facility definition for natural gas distribution facilities as follows:

> "'Facility,' with respect to natural gas distribution for the purposes of sections 95150 to 95158 of this article, means the collection of all distribution pipelines and metering-regulating stations that are operated by a local distribution company (LDC) within the State of California that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system."

1.2 Onshore Petroleum and Natural Gas Production Facility Definition

Section 95102(a)(172) of MRR includes a specialized facility definition for onshore petroleum and natural gas production facilities as follows:

> "'Facility,' with respect to onshore petroleum and natural gas production for the purposes of sections 95150 to 95158 of this article, means all petroleum and natural gas equipment on a well-pad, associated with a well pad or to which emulsion is transferred and CO2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single basin as defined in section 95102(a). When a commonly owned cogeneration plant is within the basin, the cogeneration plant is only considered part of the onshore petroleum and natural gas production facility if the onshore petroleum and natural gas production facility operator or owner has a greater than fifty percent ownership share in the cogeneration plant. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility."

1.2.1 Application of the Term "Associated with"

Onshore petroleum and natural gas system emissions sources are considered "associated with" the hydrocarbon stream produced from the well pad. This includes steam generators, dehydrators, amine treaters, and other equipment (portable and stationary) that are associated with the production and treatment of the hydrocarbon stream produced at the well pad. The "associated with" term is also inclusive of cogeneration facilities that supply steam and/or electricity to the well pad.

1.2.2 California Geologic Provinces (Basins)

Onshore petroleum and natural gas production facilities in California are required to aggregate and report applicable GHG emissions using the "basin" footprint as defined in the following publication:

AAPG-CSD Geologic Provinces Code Map, R.F. Meyer, L.G. Wallace, and F. J. Wagner, Jr., *The American Association of Petroleum Geologists Bulletin*, V. *75*, No. *10* (October 1991), pgs., 1644 – 1651, 1991.

This journal article is copyright protected and cannot be freely distributed by the California Air Resources Board (ARB). Reporters may access the complete article free of charge at many California public libraries. To aid reporters in the determination of their reporting footprint and correct basin name and number, ARB staff have constructed Table 1, which lists each California county or counties included in each basin by name and number (as defined in the reference publication). Note that, in many cases, a basin may contain multiple California counties. Offshore basins do not necessarily correspond to individual onshore California counties.

Table 1: Basin IDs Defining Oil and Natural Gas Production Facility Reporting Footprint

Basin Name	Basin Number	California County(ies)
Onshore Basins		
Southern Oregon	620	Lassen, Modoc
Great Basin	625	Inyo, Mono
Mojave	640	San Bernardino
Salton	645	Imperial, Riverside
Sierra	650	Alpine, Amador, Calaveras, El Dorado, Mariposa, Nevada, Placer, Plumas, Sierra, Tuolumne, Yuba
Klamath Mountain	715	Del Norte, Shasta, Siskiyou, Trinity
Eel River	720	Humboldt
Northern Coast Range	725	Alameda, Lake, Mendocino, Napa, Santa Clara, Sonoma
Sacramento	730	Butte, Colusa, Contra Costa, Glenn, Sacramento, San Joaquin, Solano, Sutter, Tehama, Yolo
Santa Cruz	735	Marin, Santa Clara, Santa Cruz, San Francisco, San Mateo
Coastal	740	Monterey, San Luis Obispo
San Joaquin	745	Fresno, Kern, Kings, Madera, Merced, San Benito, Stanislaus, Tulare
Santa Maria	750	Santa Barbara
Ventura	755	Ventura
Los Angeles	760	Los Angeles, Orange
Capistrano	765	San Diego
Offshore Basins		
Eel River	945	Not applicable
Point Arena	948	
Santa Cruz (Bodega)	950	
Santa Maria	953	
Santa Barbara Channel	955	
Pacific Coast (Outer)	956	
Southern California borderlands	957	

1.3 Definition of "Facility" for all Other Industry Segments

The "facility" definition in section 95102(a)(170) of MRR applies to the other industry segments listed in section 95101(e) including offshore petroleum and natural gas production, onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, and liquefied natural gas (LNG) storage, import, and export facilities. The definition is as follows:

> "'Facility,' unless otherwise specified in relation to natural gas distribution facilities and onshore petroleum and natural gas production facilities as defined in section 95102(a), means any 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 a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties."

Operators of natural gas distribution facilities and onshore petroleum and natural gas production facilities must use the definitions described in Sections 1.1 and 1.2 of this guidance document instead of this facility definition.

Note: Onshore natural gas processing facilities that fractionate or that do not fractionate but have a throughput of 25 million standard cubic feet (MMscf) per day or greater must report according to the general facility definition in section 95102(a)(170).

1.4 Examples for Applying Facility Definitions for Oil and Gas Facilities

Example 1: An onshore petroleum production operator in a single hydrocarbon basin owns greater than a 50 percent share in a cogeneration plant, which supplies steam to some of the wells for production. How many ARB facility IDs does this owner need?

> Answer: One. The cogeneration plant is associated with the onshore petroleum production facility and emissions from the cogeneration plant must be reported with the other emissions associated with the well pad within the geologic basin because the operator owns greater than a 50 percent share in the cogeneration plant as specified in the definition of "onshore petroleum and natural gas production facility" in section 95102(a).

Example 2: An oil company operates a natural gas processing plant that has a throughput of 35 MMscf/day in an oil field that consists of multiple well pads (not necessarily under common ownership) in a single hydrocarbon basin. How many ARB facility IDs are needed?

> Answer: At least two. The natural gas processing facility has a separate facility ID from the well pads. However, depending on how many owners or operators of the well pads there are in the single hydrocarbon basin, the onshore natural gas production facility may consist of one ARB facility ID or multiple ARB facility IDs.

Example 3: A liquefied natural gas storage facility is located contiguous to a commonly owned cogeneration plant. How many ARB facility IDs do the facility and plant need?

> Answer: One. The liquefied natural gas storage facility is contiguous to the cogeneration facility. Because MRR does not include a specific, specialized facility

definition for liquefied natural gas storage facilities, the general facility definition in section 95102(a) of MRR applies, so this is considered a single facility.

1.5 Reporting by Sub-facility

MRR specifies that emissions and product data must be disaggregated within the basin reporting footprint to the sub-facility level when reported via the California Electronic Greenhouse Gas Reporting Tool (Cal e-GGRT). Sub-facility is defined in terms of single townships or a group of contiguous or adjacent townships, as identified in the Public Land Survey System of the United States. Sub-facilities may be further disaggregated according to similar operational, geological, or geographical characteristics. Reporters should refer to the definition of sub-facility found in section 95102(a) of MRR for additional information. Entities that have already been reporting emissions and product data at the sub-facility level should continue reporting with the same subdivision of information; however the facility's GHG Monitoring Plan must provide a map or a list identifying the townships, ranges, and section numbers that comprise the geographic boundaries of the sub-facilities. Production data must be further disaggregated between thermal and other-than-thermal (i.e., non-thermal) production processes at the sub-facility level.

2 New and Modified Requirements for 2014 Data Reported in 2015, and for Subsequent Years

This section discusses new requirements that became effective in MRR January 1, 2015.

2.1 Requirements for Quantifying Emissions from Centrifugal Compressor Venting

A new requirement for quantifying emissions from centrifugal compressor venting was added to section 95153(m)(1)(A) of MRR. All facility operators that have centrifugal compressors that use spin-up gas to start their compressors must report these emissions. In cases where natural gas is used as spin-up or starting gas, vented emissions of this spin-up gas must be included in operating mode emissions calculations for affected compressors as per Equation 20 of section 95153(m)(1)(A) of MRR. Spin-up gas is gas that is used to start a compressor with the kinetic energy of the gas stream, and subsequently vented rather than being combusted in the compressor. If spin-up gas is captured and subsequently used as a fuel or flared, these emissions must be reported using the appropriate methods found in section 95153.

2.2 Requirements for Reporting Emissions from Customer Meters

Beginning in 2015, operators of natural gas distribution facilities must report carbon dioxide (CO_2) and methane (CH_4) emissions from customer meters pursuant to section 95152(i)(10) of MRR. Default emission factors for three types of customer meters (residential, commercial, and industrial) have been added to MRR's Appendix A, Table 7. These emission factors are listed in units of standard cubic feet (scf)/meter-hour. Operators must use the equations in section 95153(p) and the emission factors in Table 7 of Appendix A to calculate emissions from customer meters. N_2O emissions are excluded from this reporting requirement.

2.3 Requirements for Reporting Emissions from Pipeline Dig-ins

Operators of natural gas distribution facilities must also report the number and emissions from pipeline dig-ins pursuant to section 95152(i)(11) of MRR, using the methodology specified in section 95153(w).

Pipeline dig-in is defined in section 95152(a) to mean the following:

> "Pipeline dig-in' means unintentional puncture or rupture to a buried natural gas transmission and distribution pipeline during excavation activities."

Operators may use either measured data or engineering calculations based on the best available data to quantify the volume of natural gas released from pipeline dig-ins and subsequently convert and report this volumetric information as mass CH_4 and CO_2 emissions. N_2O emissions are excluded from this reporting requirement. Combustion emissions from a natural gas leak that ignites after a pipeline dig-in are not required to be reported under MRR.

2.4 Requirements to Report Sorbent Emissions

Onshore petroleum and natural gas production and natural gas distribution facilities must report sorbent emissions from fluidized bed boilers with flue gas desulfurization along with stationary combustion emissions (95153(y) of MRR). Reporters must use the methods found in United States Environmental Protection Agency (US EPA) Mandatory GHG Reporting Rule (section 40 CFR §98.33(d)) to calculate sorbent related emissions.

2.5 Requirements for Local Distribution Companies

Pursuant to sections 95157(c)(16)(U) and (V) of MRR, local distribution companies (LDC) must report CO_2 and CH_4 emissions from customer meters and pipe-line dig-ins. LDCs must also report the number of customer meters at residential, commercial, and industrial customers they serve, and the number of pipe-line dig-ins, as set-forth in sections 95157(c)(16)(W) and (X), respectively.

2.6 Voluntary Reporting of Renewable Resources to Produce Steam for EOR Operations

Section 95157(c)(19)(I) of MRR allows onshore petroleum and natural gas production facilities to voluntarily report the amount of thermal energy (in units of MMBtu) input to EOR wells that is produced using renewable energy source(s), as defined in section 95102(a).

3 Frequently Asked Questions

This section provides answers to frequently asked questions from facility operators of petroleum and natural gas systems.

3.1 If an operator does not have a certain source at its facility, can the fields in Cal e-GGRT be left blank for those sources?

No. Operators of all petroleum and natural gas facilities should report zero (0) in Cal e-GGRT where individual source emissions can be demonstrated to be zero (i.e., no emissions occurred from the source in question for the entire reporting period). This will allow ARB and the verifier to know that the operator did not have emissions associated with the specific sources instead of failing to insert data for those sources. The operator must demonstrate to the satisfaction of the verifier that no emissions occurred.

Additionally, in cases where the emissions are less than one-thousandth of a ton, the user should enter '0' into Cal e-GGRT. As mentioned above, the user should retain the records of the actual emissions for verification purposes.

3.2 Do operators have to report emissions from the blowdown of very small volumes?

Section 95153(g) of MRR requires all facility operators, except operators of offshore petroleum and natural gas production facilities, to report emissions resulting from the depressurization of equipment and pipelines caused by human intervention or taking equipment out of service for maintenance (excluding depressurizing to a flare, overpressure relief, operating pressure control and venting and blowdown of non-GHG gases, and desiccant dehydrator blowdown venting before reloading). A provision has been added to section 95153(g)(1) of MRR which exempts reporting blowdown emissions from physical volumes less than 50 cubic feet (cf).

Reporters must calculate the unique physical volume for each blowdown incident. Pursuant to section 95153(g)(1) this volume shall be determined by engineering estimates based on best available data. Actual measurements of variables such as tubing diameter and pipe length would also be acceptable.

In addition to physical blowdown volume, the following variables must also be determined:

> N = number of occurrences of blowdowns for each unique physical volume in the calendar year. Reporters should maintain a list and record the number of blowdowns per calendar year.
>
> T_a = Temperature at actual conditions. Reporters should be able to determine this variable from any number of sources: e.g., System Control and Data Acquisition (SCADA) systems, thermometer.

P_a = Absolute pressure at actual conditions in the unique physical volume. Reporters should be able to determine this value from a SCADA system or via an engineering estimate based on system standard operating parameters when actual pressure measurements are not available.

Reporters should always use the most accurate data available when deriving the variables required as inputs to this emissions calculation methodology. The verifier must review the data sources during verification to ensure that the input data meet accuracy requirements.

3.3 How do operators report emissions in cases where the compressor was in the non-operating and depressurized mode during the reporting period?

The monitoring requirements for compressors in the "not operating, depressurized mode" are detailed in sections 95153(m)(1)(C) and 95153(n)(1)(C) of MRR. If no measurement data has yet been acquired within the three year monitoring period, the operator may use an engineering estimate or best available data to determine the MT_m variable for compressors in the "not operating, depressurized mode," until the required measurement is collected.

3.4 What if sampling required under MRR exposes facility personnel to hazardous concentrations of H_2S in compressor emissions? Are operators still required to conduct sampling under these circumstances?

Activities undertaken to collect and acquire data reported under MRR should never be conducted in a manner which puts personnel safety at risk. ARB staff believes that the reporting requirements include sufficient safeguards to prevent harm to personnel involved in sampling of compressor emissions. Reporters should refer to sections 95154(a)(3) and (4) of MRR (Monitoring and QA/QC Requirements) where personnel are directed to use either an infrared laser or an optical gas imaging instrument "for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface." ARB staff believes this text covers sources which are inaccessible due to safety concerns.

Sections 95153(m) and 95153(n) of MRR describe emissions measurement and quantification methodologies for centrifugal and reciprocating compressors, respectively. These two sections specify the methods used to quantify vent emissions, which include calibrated bagging, high volume sampler, or a permanent or temporary meter."

3.5 How do operators apportion fugitive emissions measurements over the five-year period mentioned in section 95153(o)(8)(A) of MRR?

U.S. EPA has issued guidance concerning this issue and this guidance is reproduced below. Operators are directed to follow this guidance in quantifying and reporting emissions covered in section 95153(o) of MRR.

Reporter inquiry to U.S. EPA:

> "Q651. Under Section 98.233(q)(8)(i), a company may elect to conduct leak detection on a multiple year cycle, up to a maximum of five years, with the number of stations monitored 'approximately equal across all years in the cycle.' The preamble to the final rule says 'a minimum of 20%' per year (76 FR 80569). Would a monitoring plan that results in 10% of stations being monitored in each of the first two years, followed by 40% of stations in year 3, 20% in year 4 and 20% in year five, be consistent with the rule language of 'approximately equal across all years in the cycle.'"

U.S. EPA response:

> "A651. Yes. According to 98.233(q)(8)(i), 'Natural gas distribution facilities may choose to conduct leak detection at T-D transfer stations over multiple years, not exceeding a five year period to cover all T-D transfer stations. If the facility chooses to use the multiple year option, then the number of T-D transfer stations monitored in each year should be approximately equal across all years in the cycle without monitoring the same station twice during the multiple year survey.' EPA confirms that an approach of conducting monitoring at 10% of the facilities in each of the first two years, followed by 40%, 20% and 20% in years three, four and five would be consistent with the rule language that the number of stations monitored be 'approximately equal' over the number of years surveyed."

This text can be found at the following web-link:
http://www.ccdsupport.com/confluence/pages/viewpage.action?pageId=118587545.

3.6 In what cases should an operator use the "common pipe" method for reporting combustion emissions?

A "common pipe" method, as described in section 95115 of MRR, is still applicable for most fuels as described in section 95153(y)(1)(A). For combustion units that combust field gas, process vent gas, non-pipeline quality natural gas or a blend of field and process vent gas, the "common pipe" method, also applies. Section 95153(y)(2)(A) indicates that company records may be used to determine the volume of fuel combusted, and for purposes of the fuels listed in section 95153(y)(2), company records may include records related to the common pipe that transfers fuel to particular units. For reporting emissions from units downstream of the common pipe, please follow the Guidance for Aggregation of Emitting Units document.

3.7 What are the verification requirements for activity data reported pursuant to section 95157?

Facility operators for every industry segment are required to report activity data contained in section 95157 of MRR. Activity data reported under section 95157 must be verified for conformance by a third-party verification body pursuant to section 95131(b)(10). The activity data reported pursuant to section 95157 are not part of a facility's covered emissions, and as such, are not subject to material misstatement assessment.

3.8 When determining whether a natural gas source is "pipeline quality natural gas," is it acceptable for the operator to make the determination based on the annual weighted averages of monthly measurements for CH_4, CO_2, and HHV?

Yes, if the annual weighted averages of monthly measurements for CH_4, CO_2, and HHV meet the "pipeline quality natural gas" criteria for those parameters (i.e., at least 90% CH_4 by volume, less than 5 percent CO_2 by volume, and HHV between 970 and 1,100 btu/scf, inclusively), the gas may be considered "pipeline quality" for the entire data year.

3.9 Since the CO_2 emissions method in section 95153(y)(2) of MRR is based on carbon content (similar to a "Tier 3" method) and not based on a default emission factor, is it acceptable to use section 95153(y)(2) for a natural gas source that <u>does</u> meet the definition of "pipeline quality" natural gas?

Yes, the operator may choose to use the method in §95153(y)(2) to quantify combustion emissions for natural gas that does meet the "pipeline quality" definition.

3.10 If an operator follows the method in section 95153(y)(1) of MRR, because the fuel is a standard fuel or is pipeline quality natural gas, and selects an applicable Tier method from section 95115, does the operator need to follow all of the quality assurance and reporting requirements described in section 95115?

If a Tier method from section 95115 is selected to quantify combustion emissions based on the application of section 95153(y)(1), the reporter *must* follow all of the Tier selection, monitoring, sampling frequency, and other quality assurance requirements in section 95115 that are associated with quantifying emissions. For facilities in the oil and gas sector, the additional reporting requirements of section 95115 (e.g., reporting fuel use by device type for a common pipe source) are optional.

3.11 Do vented emissions from "rotary vane" compressors need to be reported?

Vented emissions from "rotary vane" compressors, and any other compressors that operate on the principle of a rotating shaft, should be reported as emissions from centrifugal compressors.

3.12 If the vented emissions from compressors are reported as *de minimis*, is it acceptable to modify or omit the vent testing requirements described in sections 95153(m) and (n) of MRR?

If the vented emissions from compressors meet the *de minimis* thresholds, and the chosen method for quantifying vented emissions is reasonable, the vent testing requirements described in sections 95153(m) and (n) may be modified or omitted. Verifiers must ensure that the methods used by the operator to quantify emissions reported as *de minimis* are reasonable, unlikely to be biased high or low, and that the actual emissions are unlikely to exceed the *de minimis* threshold.

3.13 How should compressor venting emissions be reported if the compressors are completely self-contained and have no vents or vent stacks, or if the vented emissions from vents are captured to a vapor recovery system?

If compressors have no vents or vent stacks, or if 100 percent of the vented emissions are routed to a vapor recovery system, the operator should quantify and report the vented emissions from such compressors as zero (0). Such compressors would still be subject to the reporting requirements for leaks and for fuel combustion, as described in Subarticle 5 of MRR.

3.14 How should emissions from unmetered, natural gas-powered intermittent-bleed pneumatic devices be quantified and reported, if the operator has documentation demonstrating that the actual bleed rate for the devices is less than six scf per hour?

Pursuant to MRR, "intermittent bleed devices which bleed at a cumulative rate of six standard cubic feet per hour or greater are considered high bleed devices" (section 95102(a)(252)), therefore, emissions from devices that exceed this limit must be reported as high-bleed in Cal e-GGRT and are subject to a compliance obligation under the Cap-and-Trade Program. A low-bleed pneumatic device is defined in MRR as a device that "vents continuously or intermittently bleeds to the atmosphere at a rate equal to or less than six standard cubic feet per hour" (section 95102(a)). Low-bleed pneumatic devices must be reported as low-bleed in Cal e-GGRT and emissions from such devices are not subject to a compliance obligation under the Cap-and-Trade Program.

Emissions from all unmetered, natural gas-powered intermittent-bleed pneumatic devices must be quantified using the "intermittent bleed" emission factor of

13.5 scf/hour/component listed in Table 1A of Appendix A of MRR, using Equation 2 (section 95153(b)), regardless of bleed rate. If the operator has documentation that demonstrates that the devices bleed at an actual rate of less than six scf/hour/component, such as original equipment manufacturer's specifications, or measurement data, the operator must still quantify the emissions using the 13.5 scf/hour/component emission factor; however, the emissions may be reported as "low bleed" pneumatic emissions in Cal e-GGRT. If the device bleeds at a rate of six scf/hour/component or greater, or there is no documentation available that demonstrates that the actual bleed rate of a device is less than or equal to six scf/hour/component, the emissions for such devices must be reported as "high bleed" pneumatic device emissions in Cal e-GGRT.

Verifiers must evaluate pneumatic device emissions as a part of their risk analysis during verification, including the determination of whether on-site pneumatic devices are continuous-bleed or intermittent-bleed devices. Verifiers should identify emissions from intermittent bleed devices that are reported in the "low bleed" category in Cal e-GGRT as high risk. When emissions from intermittent-bleed devices are reported in the low-bleed category in Cal e-GGRT, verifiers should review documented evidence that the actual bleed rate from the devices is less than or equal to six scf/hour.

3.15 What value should an operator use for the "Fraction of gas combusted" (η or "eta"), when using Equations 35 and 36 to quantify combustion emissions for "external" combustion devices, such as heaters or boilers?

The operator must use the default value of 0.995 for the term "η" in Equations 35 and 36 for all combustion unit types, including both "internal" and "external" combustion devices, unless the operator can provide objective evidence to the verification team to substantiate the use of a value other than the default factor of 0.995. An example of such evidence could include a gas composition analysis of a combustion unit's exhaust that demonstrates the validity of an alternative engineering estimate.

3.16 A prior version of MRR required actual component counts (methodology 1) after the 2012 data year when quantifying leaks data under section 95153(p), but the current version of MRR allows an alternate "default" component count method. If an operator chooses to use the default component count method (methodology 2), does the operator need to submit notification of a change in method to ARB, pursuant to section 95103(m)(1)?

Yes. If the operator switches from methodology 1 to methodology 2 for quantifying leaks data pursuant to section 95153(p) the operator must notify ARB of the method change pursuant to section 95103(m)(1).

3.17 Are "sulfatreat" systems, and other types of systems that use a solid iron oxide medium to remove sulfur gases, subject to emissions reporting under the "acid gas removal vent" source category?

No. The emissions quantification methods required pursuant to the "acid gas removal vent" source category are intended to quantify CO_2 emissions from systems that routinely remove CO_2 from the fuel gas stream, and then vent this CO_2 directly to the atmosphere upon regeneration of the system media (e.g., an amine solvent). Systems that use an iron oxide or other solid medium to remove sulfur gases from an enclosed stream of natural or associated gas, and that do not routinely vent CO_2 to the atmosphere, are not subject to emissions reporting under the acid gas removal vent source category in section 95153(c) because the media from these systems do not remove CO_2 from the fuel stream. However, the vessels of such systems would be subject to blowdown emissions reporting, as applicable, according to section 95153(g).

3.18 Do combustion emissions from small compressors (less than 130 horsepower) need to be reported? If so, how should those emissions be quantified if the compressor engine is powered by the gas it is compressing, and there is no fuel meter?

Yes. Combustion emissions from all compressors operated by an internal combustion engine, regardless of the rated heat capacity, must be reported as covered emissions, using the appropriate quantification method. If the fuel for such devices is not metered, the operator may quantify the fuel usage using the number of operating hours for the devices, and the demonstrated hourly fuel use rate, per the device manufacturer's specifications. However, the hours of operation and the hourly fuel use rate data (e.g., the "load" rate for the device under actual operating conditions) must meet the measurement accuracy requirements of section 95103(k). If the accuracy of the number of operating hours and/or the actual hourly fuel use rate cannot be demonstrated to the verifier, the operator may report the emissions in the de minimis category, if the requirements for de minimis reporting are met. If the operator cannot or does not wish to report the emissions in the de minimis category, the operator must use the missing data provisions to quantify the fuel use. The operator must use the maximum hourly fuel use rate for the device from the manufacturer's specifications to quantify missing fuel use rate data. If the hours of operation data are also missing, the operator must use the maximum number of hours during the data year for which the device may have been operating.

Pursuant to section 95153(y)(3), emissions from <u>external</u> fuel combustion sources (e.g., heaters and boilers) with a rated heat capacity of less than or equal to five MMBtu/hour do not need to be reported. Likewise, pursuant to 95153(y)(4), emissions from <u>internal</u> combustion sources, <u>except compressor drivers</u>, with a rated heat capacity equal to or less than one MMBtu/hour (or 130 horsepower) do not need to be reported.

3.19 How are de minimis emissions reported for oil and gas facilities in Cal e-GGRT?

To simplify reporting and ensure accurate categorization of de minimis emissions operators must report Subarticle 5 (Subpart W) de minimis emissions in the Petroleum and Natural Gas Systems – Emissions Reporting Workbook, beginning with 2015 data reported in 2016. Operators should no longer use the De Minimis Workbook to report Subpart W emissions. Operators may aggregate petroleum and natural gas systems de minimis emissions on one line of the workbook, or may choose to disaggregate the de minimis emissions by sub-facility. Operators must still disaggregate emissions that are not categorized as de minimis by sub-facility. See Figure 1 below for an example of a reporting configuration in Cal e-GGRT.

Figure 1: Example input for the Cal e-GGRT Subarticle 5 workbook "Onshore Petroleum and Natural Gas Production" section.

		Metered natural gas high bleed pneumatic device and pneumatic pump venting		
Does Entire Row Contain Standard or De Minimis Emissions? (any de minimmis emissions must be reported in separate row(s).	**Contiguous Property/Sub-Facility Name:**	CO_2 Emissions (tCO_2)	CH_4 Emissions (tCH_4)	Total CO_2e
	Total - Standard Emissions	805.0	7.0	952.0
	Total - De Minimis Emissions	125.0	2.6	179.6
Standard	Watson Shale 25	250.0	5.0	**355.0**
De Minimis	Watson Shale 25 - De Minimis	2.0	0.3	**8.3**
Standard	East Hill 23X	555.0	2.0	**597.0**
De Minimis	De Miminis Aggregation	123.0	2.3	**171.3**