(Adopted October 15, 1993)(Amended December 7, 1995)(Amended February 14, 1997)
(Amended April 11, 1997)(Amended October 20, 2000)(Amended May 11, 2001)
(Amended May 6, 2005)

RULE 2000. GENERAL

(a) Program Objective

RECLAIM is a market incentive program designed to allow facilities flexibility in achieving emission reduction requirements for Oxides of Nitrogen (NO_X), and Oxides of Sulfur (SO_X) under the Air Quality Management Plan using methods which include, but are not limited to: add-on controls, equipment modifications, reformulated products, operational changes, shutdowns, and the purchase of excess emission reductions.

(b) Purpose

This rule provides the definitions for terms found in Regulation XX - RECLAIM. Any identical term found elsewhere in District Rules and Regulations with a conflicting definition shall be superseded, for the purposes of this regulation, by the definition provided in this rule.

(c) Definitions

(1) ACTUAL EMISSIONS means the emissions of a pollutant from an affected source determined by taking into account, actual emission rates and actual or representative production rates (i.e., capacity utilization and hours of operation).

(2) AIR CONTAMINANT means any air pollutant for which there is a national ambient air standard, or precursor to such air pollutant, including but not limited to: carbon monoxide, sulfur dioxide, nitrogen oxides, particulate matter, lead compounds and volatile organic compounds.

(3) ALLOCATION is the number of RECLAIM Trading Credits (RTCs) [as defined in paragraph (c)(63)] a RECLAIM facility holds for a specific compliance year, as referenced in the Facility Permit.

(4) ALLOWABLE EMISSIONS means the emissions rate of a stationary source calculated using the maximum rated capacity of the sources (unless the source is subject to federally enforceable limits which restrict the operating rate or hours of operation, or both) and the most stringent of the following:

(A) the applicable standards set forth in 40 CFR part 60 or 61;

(B) any applicable State Implementation Plan emissions limitation, including those with a future compliance date; or

(C) the emissions rate specified as a federally enforceable permit condition, including those with a future compliance date.

(5) ALTERNATIVE EMISSION FACTOR is a SO_X emission value in units of pounds per million standard cubic feet or pounds per thousand gallons derived using the methodology specified in Appendix A, Protocols for Monitoring, Reporting, and Recordkeeping for Oxides of Sulfur (SO_X) Emissions, Chapters 3 and 4.

(6) ANNUAL PERMIT EMISSIONS PROGRAM (APEP) is the annual Facility Permit compliance reporting, review, and fee reporting program.

(7) BASIN means the South Coast Air Basin as defined by the California Air Resources Board.

(8) BEST AVAILABLE RETROFIT CONTROL TECHNOLOGY (BARCT) means an emission limitation that is based on the minor source criteria and methodology specified in the most current version of the District's BACT Guidelines. Parameters used for cost-effectiveness, such as equipment life less than ten years or operating conditions, except for hours of operation for gas turbines used as peaking units at Power Producing Facilities, shall be included as Facility Permit conditions.

(9) BEST AVAILABLE CONTROL TECHNOLOGY (BACT) means the most stringent emission limitation or control technique which:

(A) has been achieved in practice for such category or class of source; or

(B) is contained in any state implementation plan (SIP) approved by the Environmental Protection Agency (EPA) for such category or class of source; or

(C) is any other emission limitation or control technique, including process and equipment changes of basic or control equipment which is technologically feasible for such class or category of source or for a specific source, and cost-effective as compared to AQMP measures or adopted District rules.

A specific limitation or control technique shall not apply if the Facility Permit holder demonstrates that such limitation or control technique is not presently achievable. BACT shall be at least as stringent as Standards of Performance for New Stationary Sources (40 CFR Part 60).

BACT for sources located at major polluting facilities shall be at least as stringent as Lowest Achievable Emissions Rate (LAER) as defined in the federal Clean Air Act Section 171(3) [42 U.S.C. Section 7501(3)].

BACT for sources not located at major polluting facilities shall be as specified in the BACT Guidelines for such source categories, unless the BACT specified in the Guidelines is less stringent than required by state law in which case BACT shall be as defined in state law considering economic and technical feasibility.

When updating the BACT Guidelines to become more stringent for sources not located at major polluting facilities, economic and technical feasibility shall be considered in establishing the class or category of sources and the applicable requirements.

(10) BREAKDOWN means a condition caused by circumstances beyond the Facility Permit holder's control which result in fire, or mechanical or electrical failure. If the breakdown causes an emission increase at a RECLAIM facility in excess of emissions under normal operating conditions, determined pursuant to Rules 2011 - Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Sulfur (SO_X) Emissions, and 2012 - Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Nitrogen (NO_X) Emissions, and Appendices A of Rules 2011 and 2012, the excess emissions from such breakdown are not counted in determining compliance with the RECLAIM facility's annual allocation if all criteria specified in Rule 2004 (i)(2)(A) are met. Malfunctions in monitoring, reporting, and recordkeeping equipment as required by Rule 2011 and Rule 2012 shall not be considered to be a breakdown under Rule 2004 (i).

(11) BUYER is any person who acquires RTCs from another person through purchase, trade or other means of transfer.

(12) CEMENT KILN is a device for the calcining and clinkering of limestone, clay and other raw materials, and recycle dust in the dry-process manufacture of cement.

(13) CERTIFIED REPORT means there has been a reasonable and diligent inquiry into the accuracy of the report by the certifying official and that the contents of the report are true and accurate to the best of his or her knowledge.

(14) CLINKER is a mass of fused material produced in a cement kiln from which the finished cement is manufactured by milling and grinding.

(15) COMBUSTION EQUIPMENT is any equipment that burns fuel, including but not limited to natural gas or fuel oil in order to operate. Combustion equipment includes, but is not limited to, boilers, turbines, heaters, engines, kilns, furnaces, ovens, dryers, flares, and afterburners.

(16) COMPLIANCE YEAR is the twelve-month period beginning on January 1 and ending on December 31 for Cycle 1 facilities, and beginning on July 1 and ending on June 30 for Cycle 2 facilities.

(17) CONCENTRATION LIMIT is a value expressed in ppmv, is measured over any continuous 60 minutes, is elected by the Facility Permit holder for a large NO_X source or a super compliant SOx major source which has been reclassified as a SOx process unit, and is specified in the Facility Permit.

(18) CONTINUOUS EMISSIONS MONITORING SYSTEM (CEMS) means the equipment required by the Protocols for Monitoring, Reporting and Recordkeeping for Oxides of Sulfur (SO_X) and Oxides of Nitrogen (NO_X) Emissions used to continuously measure all parameters necessary to determine mass emissions expressed in pounds per hour (lb/hr) for SO_X and NO_X. A CEMS includes, but is not limited to, the following component parts and systems:

(A) sulfur dioxide pollutant concentration monitor;

(B) flow monitor;

(C) nitrogen oxides pollutant concentration monitor;

(D) diluent gas monitor (oxygen or carbon dioxide);

(E) a data acquisition and handling system;

(F) moisture monitor, as applicable; and

(G) sample acquisition, conditioning, and transport system, as applicable.

(19) CONTINUOUS PROCESS MONITORING SYSTEM (CPMS) is equipment that measures process parameters including, but not limited to, fuel usage rate, oxygen content of stack gas, or process weight, and meets all performance standards for CPMS set forth in the Protocol for Monitoring, Reporting and Recordkeeping for Oxides of Nitrogen (NO_X) Emissions. Such CPMS data will be used in conjunction with the concentration limit or emission rate, as stated in the Facility Permit, to determine mass NO_X emissions.

(20) CONTINUOUSLY MEASURE means to measure at least once every 15 minutes except during periods of routine maintenance and calibration, or as otherwise specified in the Protocols for Monitoring, Reporting, and Recordkeeping Oxides of Nitrogen (NO_X) and Oxides of Sulfur (SO_X) Emissions.

(21) CONTRACTOR means a person, other than the facility permit holder and its employees, who operates equipment at a RECLAIM facility.

(22) DAILY means occurring once between 12 midnight and 24 hours later at midnight.

(23) DIRECT MONITORING DEVICE is a device that measures the emissions of NO_X or SO_X or fuel sulfur content and all other variables as specified in Rules and Protocols for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NO_X) and Oxides of Sulfur (SO_X) Emissions.

(24) DISTRICT CENTRAL NO_X STATION is the District's designated computer system for NO_X emission monitoring.

(25) DISTRICT CENTRAL SO_X STATION is the District's designated computer system for SO_X emission monitoring.

(26) ELECTRIC UTILITY is all in-Basin facilities which generate power and are owned or operated by any one of the following: Southern California Edison, Los Angeles Department of Water and Power, City of Burbank, City of Glendale, City of Pasadena, or any of their successors.

(27) ELECTRONICALLY REPORT means transmitting measured data between the point of measurement and the point of receipt of the transmission, as specified in Rules 2011 and 2012 and their Appendices.

(28) EMERGENCY STANDBY EQUIPMENT is equipment solely used on a standby basis in cases of emergency and is listed as emergency equipment on the Facility Permit; or is equipment that does not operate more than 200 hours per compliance year and is listed as emergency equipment in the Facility Permit.

(29) EMISSION FACTOR is the applicable value specified in Tables 1 or 2 of Rule 2002.

(30) EMISSION RATE is a value expressed in terms of NO_X mass emissions per unit of heat input, is derived using the methodology specified in the Protocol for Monitoring, Reporting and Recordkeeping for Oxides of Nitrogen (NO_X) Emissions, and is used to calculate NO_X mass emissions on an average basis.

(31) EMISSION REDUCTION CREDIT (ERC) means the amount of credit for emission reductions verified and determined by the Executive Officer pursuant to Regulation XIII - New Source Review.

(32) ENTRY is the process by which a facility not included in the RECLAIM program pursuant to Rule 2001 - Applicability, can enter the program pursuant to conditions established in Rule 2001.

(33) EXTERNAL OFFSET means an emission reduction determined pursuant to Rule 1309(b)(1) and approved by the Executive Officer for use to mitigate an emission increase, where the emission reduction is made at a facility other than the facility creating the emission increase.

(34) EXISTING EQUIPMENT is any equipment operating at a RECLAIM facility for which there was a District Permit to Construct, temporary Permit to Operate, or Permit to Operate, or equipment which existed but was exempt pursuant to Rule 219 - Equipment Not Requiring a Written Permit Pursuant to Regulation II, before October 15, 1993.

(35) EXISTING FACILITY is any facility that submitted Emission Fee Reports pursuant to Rule 301- Permit Fees, for 1992 or earlier years, or with valid District Permits to Operate issued prior to October 15, 1993, and continued to be in operation or possess valid District permits on October 15, 1993.

(36) EXPIRATION DATE is the last date a pollutant can be emitted under the authority conveyed by a Facility Permit specifying allowable emissions based upon the amount of RTCs held by a Facility Permit holder.

(37) FACILITY means any source or grouping of sources or other air contaminant-emitting activities which are located on one or more contiguous properties within the Basin in actual physical contact, or separated solely by a public roadway or other public right-of-way, and are owned or operated by the same person (or by persons under common control) or an Outer Continental Shelf (OCS) source as defined in 40 CFR Section 55.2. Such above-described groupings, if on noncontiguous properties, connected only by land carrying a pipeline, shall not be considered one facility. Equipment or installations involved in crude oil and gas production in Southern California Coastal or OCS waters and transport of such crude oil and gas in Southern California Coastal or OCS waters shall be included in the same facility which is under the same ownership or use entitlement as the crude oil and gas facility on-shore.

(38) FACILITY PERMIT is a permit which consolidates permits for existing equipment, a permit for previously non-permitted NO_X and/or SO_X emitting Rule 219 equipment, and permits for any new equipment, into a single permit. A Facility Permit shall serve as a Permit to Construct new or altered equipment, pursuant to Rule 201 and a Permit to Operate, pursuant to Rules 202(a), 202(b) and 203, for all equipment at a RECLAIM facility. Requirements for non-RECLAIM pollutants shall also be included in the Facility Permit.

(39) FEDERALLY ENFORCEABLE means all permit limitations and conditions which are enforceable by the EPA Administrator.

(40) FUNCTIONALLY IDENTICAL SOURCE REPLACEMENT is the replacement of an existing source with another source that performs the same function, and has a maximum rated capacity less than or equal to the source being replaced.

(41) GASEOUS FUELS include, but are not limited to, any natural, process, synthetic, landfill, sewage digester or waste gases with a gross heating value of 300 Btu per cubic foot or higher, at standard conditions.

(42) HIGH EMPLOYMENT/LOW EMISSIONS FACILITY (HILO) is a new facility which has a high employment to pollution ratio. A HILO Facility has an emission rate for NO_X, SO_X, ROC, and PM_{10}, per full-time manufacturing employee, that is equal to or less than one-half (1/2) of any estimate stated in the AQMP for emissions per full-time manufacturing employee by industry class in the year 2010.

(43) ISSUE DATE is the first date a pollutant can be emitted under the authority conveyed by a Facility Permit specifying allowable emissions based upon the amount of RTCs held by a Facility Permit holder.

(44) MAJOR MODIFICATION means any modification, at an existing major polluting facility that will cause:

(A) an increase of one or more pounds per day, of the facility's potential to emit oxides of nitrogen (NO_X) or volatile organic compounds (VOCs) provided the facility is located in the South Coast Air Basin; or

(B) an increase of 40 tons per year or more, of the facility's potential to emit oxides of sulfur (SO_X); or

(C) an increase of 15 tons per year or more, of the facility's potential to emit particulate matter with an aerodynamic diameter of less than or equal to a nominal ten microns (PM_{10}); or

(D) an increase of 100 tons per year or more, of the facility's potential to emit carbon monoxide (CO).

For an existing major polluting facility located in the Riverside County portion of the Salton Sea Air Basin (SSAB) and the Riverside County non-Palo Verde area of the Mojave Desert Air Basin (MDAB), major modification means any modification that will cause an increase of 25 tons per year or more, of the facility's potential to emit NO_X or VOC; whereas the requirements for SO_X, PM_{10} and CO are as specified above in paragraphs (44)(B), (44)(C), and (44)(D).

(45) MAJOR STATIONARY SOURCE means any facility which emits, or has the potential to emit 10 tons per year or more of NO_X or 100 tons per year or more of SO_X.

(46) MANUFACTURING EMPLOYEES are those full-time employees directly involved in the manufacture or sale of the product created by a RECLAIM facility.

(47) MITIGATION FEE PROGRAM means a program where power producing facilities that exceed annual allocations and meet specified applicability requirements in Rule 2004 subdivision (o), pay a participation fee to the District for generation of NO_x emission reductions by the District to mitigate emission exceedances.

(48) MODIFICATION means any physical change or change in the method of operation of a source. The following shall not be considered a modification: (A) routine maintenance and repair; (B) any change in operator or ownership of the facility; (C) use of an alternative fuel as required by District rule or federal or state statute, regulation or law; and, (D) an increase in the hours of operation or in the production rate, unless a permit condition limiting hours of operation, throughput or mass emissions would be exceeded.

(49) MONTHLY EMISSIONS REPORT is a report which takes inventory of all RECLAIM pollutant emissions at a facility during a calendar month, submitted by the Facility Permit holder to the Executive Officer, within 30 days of the close of each month.

(50) NATURAL GAS is a mixture of gaseous hydrocarbons, with at least 80 percent methane (by volume), and of pipeline quality, such as the gas sold or distributed by any utility company regulated by the California Public Utilities Commission.

(51) NEW FACILITY is any facility which has received all District Permits to Construct on or after October 15, 1993.

(52) NON-RECLAIM POLLUTANTS are those pollutants other than RECLAIM NO_X and SO_X.

(53) NORMAL OPERATING CONDITION means the condition that conforms with the established norm or standard prescribed in Rule 2011 - Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Sulfur (SO_X) Emissions and Rule 2012 - Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NO_X) Emissions, and the Appendices thereto.

(54) NO_X EMISSIONS means the sum of nitric oxides and nitrogen dioxides emitted, calculated as nitrogen dioxide.

(55) ON-SITE, OFF-ROAD MOBILE SOURCES means non-stationary devices powered by an internal combustion engine or motor of 50 horsepower or greater, used off public roads and solely at the facility to propel, move, or draw persons or property. Such devices include, but are not limited to: forklifts, aerial lifts, motor graders, backhoes, excavators, dozers, trenchers, and tractors.

(56) POWER PRODUCING FACILITY is an electric utility as defined in (c)(26), operated as of May 11, 2001, which has a generation capacity of 50 megawatts or more of electrical power.

(57) QUARTER is a three-month period from January 1 to March 31, April 1 to June 30, July 1 to September 30, or October 1 to December 31, inclusive.

(58) QUARTERLY CERTIFICATION OF EMISSIONS is a certified report inventorying all RECLAIM pollutant emissions at a facility during a quarter.

(59) RATED BRAKE HORSEPOWER (bhp) is the maximum rating specified by the manufacturer and listed on the nameplate.

(60) RECLAIM is the Regional Clean Air Incentives Market established by this Regulation.

(61) RECLAIM AIR QUALITY INVESTMENT PROGRAM (RECLAIM AQIP) is a voluntary emission reduction compliance option for RECLAIM facilities pursuant to Rule 2004 subdivision (p), where a participation fee is paid by the RECLAIM facility to the District for generation of NO_x emission reductions by the District.

(62) RECLAIM POLLUTANTS are NOx emissions and SOx emissions at a facility subject to RECLAIM requirements excluding any NOx or SOx emissions from on-site, off-road mobile sources and any SO_X emissions from equipment burning natural gas exclusively, unless the emissions are SO_X emissions at a facility that elected to enter RECLAIM pursuant to Rule 2001 (i)(2)(A) and including NOx and SOx emissions:

(A) from rental equipment as required to be reported by the Facility Permit holder pursuant to Rule 2011, Appendix A, Chapter 1 or Rule 2012, Appendix A, Chapter 1;

(B) from equipment operated by a contractor as required to be reported by the Facility Permit holder pursuant to Rule 2011, Appendix A, Chapter 1 or Rule 2012, Appendix A, Chapter 1;

(C) from ships during the loading or unloading of cargo and while at berth at a RECLAIM facility which was required to provide offsets pursuant to Rule 2005 paragraph (b)(2) and subdivision (f) for these emissions; and

(D) from non-propulsion equipment on ships within Coastal Waters under District jurisdiction and from ships destined for or traveling from a RECLAIM facility which was required to provide offsets pursuant to Rule 2005 paragraph (b)(2) and subdivision (f) for these emissions.

(63) RECLAIM TRADING CREDIT (RTC) is a limited authorization to emit a RECLAIM pollutant in accordance with the restrictions and requirements of District rules and state and federal law. Each RTC has a denomination of one pound of RECLAIM pollutant and a term of one year, and can be held as part of a facility's Allocation or alternatively may be evidenced by an RTC Certificate.

(64) RECLAIM TRADING CREDIT LISTING is maintained by the Executive Officer and is the official and controlling record of RTCs held by any person.

(65) REMOTE TERMINAL UNIT (RTU) is a data collection and transmitting device used to transmit data and calculated results to the District Central Station Computer.

(66) RENTAL EQUIPMENT is equipment which is rented or leased for operation by someone other than the owner of the equipment.

(67) REPORTED VALUE, for the purpose of developing Allocations, means the emissions data provided to the District by the facility representative, pursuant to Rule 301.

(68) RTC CERTIFICATES are issued by the District and constitute evidence of RTCs held by any person and are used for information only. The official and controlling record of RTCs held by any person is the RTC listing maintained by the Executive Officer.

(69) RESEARCH OPERATIONS are those operations the sole purpose of which is to permit investigation of experimental research to advance the state of knowledge or state-of-the-art technology.

(70) SELLER is any person who transfers RTCs to another person through sale, trade or other means of transfer.

(71) SOURCE is any individual unit, piece of equipment or process which may emit an air contaminant and which is identified, or required to be identified, in the RECLAIM Facility Permit.

(72) SO_X EMISSIONS means sulfur dioxides emitted.

(73) STANDARD INDUSTRIAL CODE (SIC) is the classification number assigned to a facility based on its primary economic activity as specified in the "Standard Industrial Classification Manual," published by the Office of Management and Budget, dated 1987.

(74) STRUCTURAL BUYER is any RECLAIM facility which has not sold RTCs as of May 1, 2000 for any compliance year during which the RECLAIM AQIP is requested and meets one of the following criteria:

(A) was or is initially totally permitted for construction of new equipment on or after October 15, 1993; or

(B) emitted 6 tons or less of NO_x in the 1999 compliance year, provided:

(i) all equipment requiring a permit at the facility is equipped with a minimum of BARCT as defined in paragraph (c)(8); and

(ii) the emission reductions requested through RECLAIM AQIP do not exceed 50 percent of the facility's emissions in compliance year 1999.

(75) THROUGHPUT means a measure of activity including, but not limited to: weight of glass pulled for a glass melting furnace, weight of clinker for cement kilns, amount of nitric acid used in metal stripping processes, amount of nitric or sulfuric acid manufactured for nitric or sulfuric acid manufacturing processes, weight of aluminum produced for aluminum production and/or fuel usage for all other sources as reported pursuant to Rule 301.

(76) TRADING ZONE is one of two areas delineated in Rule 2005 - New Source Review for RECLAIM, Map 1.

(77) ZONE OF ORIGINATION is the trading zone or Regulation XIII zone in which an RTC is originally assigned by the District.

3/17/17

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

(Adopted October 15, 1993)(Amended December 7, 1995)
(Amended February 14, 1997)(Amended May 11, 2001)(Amended January 7, 2005)
(Amended May 6, 2005)(Amended December 4, 2015)

RULE 2001. APPLICABILITY

(a) Purpose

This rule specifies criteria for inclusion in RECLAIM for new and existing facilities. It also specifies requirements for sources electing to enter RECLAIM and identifies provisions in District rules and regulations that do not apply to RECLAIM sources.

(b) Criteria for Inclusion in RECLAIM

The Executive Officer will maintain a listing of facilities which are subject to RECLAIM. The Executive Officer will include facilities, unless otherwise exempted pursuant to subdivision (i), if emissions fee data for 1990 or any subsequent year filed pursuant to Rule 301 - Permit Fees, shows four or more tons per year of NO_X or SO_X emissions where:

(1) NO_X emissions do not include emissions from:

(A) any NO_X source which was exempt from permit pursuant to Rule - 219 Equipment Not Requiring A Written Permit Pursuant to Regulation II;

(B) any NO_X process unit which was rental equipment with a valid District Permit to Operate issued to a party other than the facility;

(C) on-site, off-road mobile sources; or

(D) ships as specified in Rule 2000(c)(62)(C) and (D).

(2) SO_X emissions do not include emissions from:

(A) any SO_X source which was exempt from permit pursuant to Rule - 219 Equipment Not Requiring A Written Permit Pursuant to Regulation II; or

(B) any SO_X source that burned natural gas exclusively, unless the emissions are at a facility that elected to enter the program pursuant to subparagraph (i)(2)(A); or

(C) any SO_X process unit which was rental equipment with a valid District Permit to Operate issued to a party other than the facility;

(D) on-site, off-road mobile sources; or

(E) ships as specified in Rule 2000(c)(62)(C) and (D).

The Executive Officer will not include a facility in RECLAIM if a permit holder requests exclusion no later than January 1, 1996 and demonstrates prior to October 15, 1993 through the addition of control equipment, the possession of a valid Permit to Construct for such control equipment, or a Permit to Operate condition that the emissions fee data received pursuant to Rule 301, which shows emissions equal to or greater than four tons per year of a RECLAIM pollutant, is not representative of future emissions.

(c) Amendments to RECLAIM Facility Listing

(1) The Executive Officer will amend the RECLAIM facility listing to add, delete, change designation of any facility or make any other necessary corrections upon any of the following actions:

(A) Approval by the Executive Officer pursuant to Rule 2007 - Trading Requirements, of the permanent transfer or relinquishment of all RTCs applicable to a facility.

(B) Approval by the Executive Officer of a change of Facility Permit holder or change of facility name.

(C) Approval by the Executive Officer of a Facility Permit for a new facility if such new facility would, under RECLAIM, have a starting Allocation equal to or greater than four tons per year of a RECLAIM pollutant NO_X or SO_X, unless the facility would be exempt pursuant to subdivision (i).

(D) Approval by the Executive Officer of a Facility Permit for an existing non-RECLAIM facility, which reports NO_X or SO_X emissions pursuant to Rule 301 - Permit Fees, for any year which are equal to or greater than four tons, as specified in subdivision (b), unless the facility would be exempt pursuant to subdivision (i).

(E) Approval by the Executive Officer of the election of a facility to enter the RECLAIM program pursuant to subdivision (f).

(F) Upon delegation of authority from EPA to the District for Outer Continental Shelf (OCS) sources and inclusion of RECLAIM in 40 CFR Part 55 pursuant to the consistency update process, such OCS sources shall be RECLAIM facilities. The OCS sources' starting Allocation for the year of entry and Allocations for the years 2000 and 2003 and interim years, shall be determined pursuant to Rule 2002 - Allocations for Oxides of Nitrogen (NO_X) and Oxides of Sulfur (SO_X), except that fuel usage and emissions data reported to the Minerals Management Service of the Department of the Interior be utilized where emissions data reported pursuant to Rule 301 is not available, provided that the permit holder substantiates the accuracy of such fuel usage and emissions data. The starting Allocation shall be adjusted to reflect the rate of reduction which would have been applicable to the facility if it had been in the RECLAIM program as of October 15, 1993.

(2) The actions specified in this subdivision shall be effective only upon amendment of the Facility Listing.

(d) Cycles

(1) The Executive Officer will assign RECLAIM facilities to one of two compliance cycles by computer-generated random assignment which, to the extent possible, ensures an even distribution of RTCs. The Facility Listing will distinguish between Cycle 1 facilities, which will have a compliance year of January 1 to December 31 of each year, and Cycle 2 facilities, with a compliance year of July 1 to June 30 of each year.

(2) The issue and expiration dates of the RTCs allocated to a facility shall coincide with the beginning and ending dates of the facility's compliance year.

(3) Within 30 days of October 15, 1993, facilities assigned to Cycle 2 may petition the Executive Office or the Hearing Board to change their cycle designation. Facilities assigned to Cycle 1 may not petition the Executive Officer or Hearing Board to change their cycle designation. Facilities entering the RECLAIM program after October 15, 1993 will be assigned to the cycle with the greatest amount of time remaining in the compliance year.

(e) High Employment/Low Emissions (HILO) Facility Designation

A new facility may, after January 1, 1997 apply to the District for classification as a HILO Facility. The Executive Officer will approve the HILO designation upon the determination that the emission rate for NO_X, SO_X, ROC, and PM_{10} is less than or equal to one-half (1/2) of any target specified in the AQMP for emissions per full-time manufacturing employee by industry class in the year 2010.

(f) Entry Election

(1) A non-RECLAIM facility may elect to permanently enter the RECLAIM program, provided that:

(A) the owner or operator files an Application for Entry;

(B) the facility is not listed as exempt under paragraph (i)(1);

(C) the facility is not operating under an Order for Abatement or in violation of any District rule; and

(D) the facility is not subject to a compliance date in an existing rule within six months of the date of Application for Entry.

(2) Upon approval of an Application for Entry, the Executive Officer will issue a Facility Permit. The facility's starting Allocation for the year of entry and Allocations for the years 2000 and 2003 and interim years, shall be determined pursuant to Rule 2002 - Allocations for Oxides of Nitrogen (NO_X) and Oxides of Sulfur (SO_X). If necessary, the Allocation shall be adjusted to equal the Allocations which would have been applicable to the facility if it had been subject to the RECLAIM program as of October 15, 1993.

(3) Entry into the RECLAIM program will be effective upon issuance of a Facility Permit pursuant to Rule 2006 - Permits, and publication of the addition of the facility to the Facility Listing.

(g) Exit from RECLAIM

(1) The owner or operator of an electricity generating facility (EGF) may submit a plan application (i.e., opt-out plan) subject to plan fees specified in Rule 306 to request to opt-out of the NOx RECLAIM program provided that the following requirements are met as demonstrated in an opt-out plan submitted to the Executive Officer:

(A) At least 99 percent of the EGF's NOx emissions for the most recent three full compliance years are from equipment that meets current Best Available Control Technology (BACT) or Best Available Retrofit Control Technology (BARCT), for NOx.

(B) The EGF is subject to NOx RECLAIM as of December 4, 2015 or has been subject to NOx RECLAIM for at least 10 years as of the plan submittal date.

For the purpose of this rule an electricity generating facility (EGF) is a NOx RECLAIM facility that generates electricity for distribution in the state or local grid system, excluding cogeneration facilities.

(2) If the Executive Officer approves an opt-out plan, based on the criteria specified in paragraph (g)(1), then the EGF Facility Permit holder shall submit applications to include in its permit and accept permit conditions that ensure all of the following apply:

(A) NOx RTCs held by the EGF shall be treated as follows:

(i) For an EGF that does not meet the definition of an existing facility, as defined in Rule 2000(c)(35), the quantity of NOx RTCs for all compliance years after the date of approval of the opt-out plan required to be held by the EGF pursuant to Rule 2005 – New Source Review for RECLAIM shall be surrendered by the facility, retired from the market, and used to satisfy any NOx requirements for continuing obligations under Regulation XIII – New Source Review. If needed to equal this amount, any Non-tradable/Non-usable RTCs and any RTCs corresponding to the EGF's contribution to the Regional NSR Holding Account may be used for this purpose and, if RTCs from the Regional NSR Holding Account are used, these RTCs shall be removed from the Regional NSR Holding Account.

(ii) For existing EGFs, that meet the definition of an existing facility, as defined in Rule 2000(c)(35), an amount of NOx RTCs equivalent to the EGF's NOx holdings as of September 22, 2015 adjusted pursuant to Rule 2002(f)(1) for all compliance years after the date of approval of the opt-out plan shall be surrendered by the EGF and retired from the market.

(iii) Any NOx RTCs held by an EGF beyond those referred to in clauses (i) and (ii) above may be sold, traded, or transferred by the facility.

(B) The EGF operator shall ensure that all equipment identified in the opt-out plan as meeting BACT or BARCT shall not exceed the respective BACT or BARCT levels of emissions or any existing permit condition limiting NOx emissions that is lower than BACT or BARCT as of the date of the opt-out plan submittal.

(C) Limits on EGF Emissions

(i) For an EGF that meets the definition of an existing facility in Rule 2000(c)(35), total facility emissions shall be limited to the amount of Compliance Year 2015 RTCs held as of September 22, 2015.

(ii) For an EGF that does not meet the definition of an existing facility in Rule 2000(c)(35), emissions from each NOx source shall be limited to the amount of RTCs required to be held for that source pursuant to Rule 2005 as of the date of opt-out plan approval.

(D) The owner or operator of multiple EGFs under common control shall have one opportunity to apportion the NOx emission limits among its facilities under common control for the purpose of meeting the requirements of clause (C)(i) or (C)(ii) as part of its opt-out plan as specified in paragraph (g)(1), provided all of the facilities opt out concurrently. The apportionment shall be described in the opt-out plan that shall be submitted to the Executive Officer. Each facility shall not have a limit that exceeds the amount of emissions that can be generated by all equipment located at the facility.

(E) Subdivision (j) shall not be applicable to the EGF for any equipment installed or modified after the date of approval of the opt-out plan, and for other equipment at the earliest practicable date but no later than three years after the date of approval of the opt-out plan except Regulation XIII – New Source Review shall apply upon permit issuance.

(F) Notwithstanding the requirements specified in subparagraph (g)(2)(E), the EGF operator shall continue to comply with the requirements of Rule 2012 and its associated protocols unless the Executive Officer has approved an alternative monitoring and recordkeeping plan which is sufficient to determine compliance with all applicable rules.

(G) Notwithstanding the requirements specified in subparagraph (g)(2)(E), for EGFs not subject to Regulation XXX, the EGF's permit shall be re-designated as an "opt-out facility permit" and shall remain in effect, subject to annual renewal, unless expired, revoked, or modified pursuant to applicable rules. The EGF operator shall continue to pay RECLAIM permit fees pursuant to Rule 301(l).

(3) The Executive Officer shall approve or deny the opt-out plan within 180 days of receipt of a complete plan, unless the EGF and the Executive Officer have mutually agreed upon a longer time period. The Executive Officer shall not approve the opt-out plan unless it has been determined that the requirements of subparagraphs (g)(1)(A) and (g)(1)(B) are met, and the EGF accepts appropriate permit conditions to ensure compliance with the requirements of subparagraphs (g)(2)(B) through (H). If, within 180 days or within the mutually agreed upon time period of receiving a complete opt-out plan, the Executive Officer does not take action on the plan, the EGF may consider the plan denied. Executive Officer denial of an opt-out plan can be appealed to the Hearing Board. The Executive Officer shall not re-issue the facility permit removing the EGF from RECLAIM unless the EGF surrenders the required amount of RTCs pursuant to subparagraph (g)(2)(A). Removal from RECLAIM of an EGF with an approved opt-out plan is effective upon issuance of a facility permit incorporating the conditions specified in paragraph (g)(2).

(4) No facility, on the initial Facility Listing or subsequently admitted to RECLAIM, may opt out of the program, unless approved by the Executive Officer pursuant to paragraph (g)(3).

(h) Non-RECLAIM Facility Generation of RTCs

Non-RECLAIM facilities may not obtain RTCs due to a shutdown or curtailment of operations which occurs after October 15, 1993. ERCs generated by non-RECLAIM facilities may not be converted to RTCs if the ERCs are based on a shutdown or curtailment of operations after October 15, 1993.

(i) Exemptions

(1) The following sources, including those that are part of or located on a Department of Defense facility, shall not be included in RECLAIM and are prohibited from electing to enter RECLAIM:

(A) dry cleaners;

(B) fire fighting facilities;

(C) construction and operation of landfill gas control, processing or landfill gas energy recovery facilities;

(D) facilities which have converted all sources to operate on electric power prior to October 15, 1993;

(E) police facilities;

(F) public transit;

(G) restaurants;

(H) potable water delivery operations;

(I) facilities located in the Riverside County portions of the Salton Sea and Mojave Desert Air Basins, except for a facility that has elected to enter the RECLAIM program pursuant to subparagraph (i)(2)(M); and

(J) facilities that have permanently ceased operations of all sources before January 1, 1994.

(K) The facility was removed from RECLAIM pursuant to paragraph (g)(3).

(2) The following sources, including those that are part of or located on a Department of Defense facility, shall not be initially included in RECLAIM but may enter the program pursuant to subdivision (f):

(A) electric utilities (exemption only for the SO_X program);

(B) equipment rental facilities;

(C) facilities possessing solely "various location" permits;

(D) hospitals;

(E) prisons;

(F) publicly owned municipal waste-to-energy facilities;

(G) portions of facilities conducting research operations;

(H) schools or universities;

(I) sewage treatment facilities which are publicly owned and operated consistent with an approved regional growth plan;

(J) electric power generating systems owned and operated by the City of Burbank, City of Glendale or City of Pasadena or any of their successors;

(K) ski resorts;

(L) facilities located on San Clemente Island;

(M) any electric generating facility that has submitted complete permit applications for all equipment requiring permits at the facility on or after January 1, 2001 may elect to enter the NOx RECLAIM program if the facility is located in the Riverside County portions of the Salton Sea or Mojave Desert Air Basins;

(N) facilities that are an agricultural source as defined in California Health and Safety Code § 39011.5; and

(O) any EGF as defined in paragraph (g)(1), except for an EGF that has been removed from NOx RECLAIM, pursuant to paragraph (g)(3).

(j) Rule Applicability

Facilities operating under the provisions of the RECLAIM program shall be required to comply concurrently with all provisions of District rules and regulations, except those provisions applicable to NOx emissions under the rules listed in Table 1, shall not apply to NO_X emissions from NOx RECLAIM facilities, and those provisions applicable to SOx emissions of the rules listed in Table 2 shall not apply to SOx emissions from SOx RECLAIM facilities after the later of the following:

(1) December 31, 1994 for Cycle 1 facilities and June 30, 1995 for Cycle 2 facilities; or

(2) the date the facility has demonstrated compliance with all monitoring and reporting requirements of Rules 2011 or 2012, as applicable.

Notwithstanding the above, NOx and SOx RECLAIM facilities shall not be required to comply with those provisions applicable respectively to NOx and SOx emissions of the listed District rules in Tables 1 and 2 which have initial implementation dates in 1994. The Facility Permit holder shall comply with all other provisions of the rules listed in Table 1 and 2 relating to any other pollutant.

Table 1

EXISTING RULES
NOT APPLICABLE TO RECLAIM FACILITIES FOR
REQUIREMENTS PERTAINING TO NO_X EMISSIONS

RULE	DESCRIPTION
218	Stack Monitoring
429	Start-up & Shutdown Exemption Provisions for NO_X
430	Breakdown Provision
474	Fuel Burning Equipment - NO_X
476	Steam Generating Equipment
1109	Emis. of NO_X Boilers & Proc. Heaters in Petroleum Refineries
1110	Emis. from Stationary I. C. Engines (Demo.)
1110.1	Emis. from Stationary I. C. Engines
1110.2	Emis. from Gaseous and Liquid-Fueled I. C. Engines
1112	Emis. of NO_X from Cement Kilns
1117	Emis. of NO_X from Glass Melting Furnaces
1134	Emis. of NO_X from Stationary Gas Turbines
1135	Emis. of NO_X from Electric Power Generating Systems
1146	Emis. of NO_X from Boilers, Steam Generators, and Proc. Heaters
1146.1	Emis. of NO_X from Small Boilers, Steam Generators, and Proc. Heaters
1159	Nitric Acid Units - Oxides of Nitrogen
Reg. XIII	New Source Review

Table 2

EXISTING RULES
NOT APPLICABLE TO RECLAIM FACILITIES FOR
REQUIREMENTS PERTAINING TO SO_X EMISSIONS

RULE	DESCRIPTION
53	Sulfur Compounds - Concentration - L.A. County
53	Sulfur Compounds - Concentration - Orange County
53	Sulfur Compounds - Concentration - Riverside County
53	Sulfur Compounds - Concentration - San Bernardino County
53A	Specific Contaminants - San Bernardino County
218	Stack Monitoring
430	Breakdown Provisions
407	Liquid and Gaseous Air Contaminants
431.1	Sulfur Content of Gaseous Fuels
431.2	Sulfur Content of Liquid Fuels
431.3	Sulfur Content of Fossil Fuels
468	Sulfur Recovery Units
469	Sulfuric Acid Units
1101	Secondary Lead Smelters/Sulfur Oxides
1105	Fluid Catalytic Cracking Units SO_X
1119	Petroleum Coke Calcining Operations - Oxides of Sulfur
Reg. XIII	New Source Review

3/17/17

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

(Adopted October 15, 1993)(Amended March 10, 1995)(Amended December 7, 1995)
(Amended July 12, 1996)(Amended February 14, 1997)(Amended May 11, 2001)
(Amended January 7, 2005)(Amended November 5, 2010)(Amended December 4, 2015)
(Amended October 7, 2016)

RULE 2002. ALLOCATIONS FOR OXIDES OF NITROGEN (NO_X) AND OXIDES OF SULFUR (SOx)

(a) Purpose

The purpose of this rule is to establish the methodology for calculating facility Allocations and adjustments to RTC holdings for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx).

(b) RECLAIM Allocations

(1) RECLAIM Allocations will begin in 1994.

(2) An annual Allocation will be assigned to each facility for each compliance year starting from 1994.

(3) Allocations and RTC holdings for each year after 2011 are equal to the 2011 Allocation and RTC holdings, as determined pursuant to subdivision (f) unless, as part of the AQMP process, and pursuant to Rule 2015 (b)(1), (b)(3), (b)(4), or (c), the District Governing Board determines that additional reductions are necessary to meet air quality standards, taking into consideration the current and projected state of technology available and cost-effectiveness to achieve further emission reductions.

(4) The Facility Permit or relevant sections thereof shall be re-issued at the beginning of each compliance year to include allocations determined pursuant to subdivisions (c), (d), (e), and (f) and any RECLAIM Trading Credits (RTC) obtained pursuant to Rule 2007 - Trading Requirements for the next fifteen years thereafter and any other modifications approved or required by the Executive Officer.

(5) Annual emission reports submitted pursuant to Rule 301 more than five years after the original due date shall not be considered by the Executive Officer in determining facility Allocations.

(c) Establishment of Starting Allocations

(1) The starting Allocation for RECLAIM NO_X and SO_X facilities initially permitted by the District prior to October 15, 1993, shall be determined by the Executive Officer utilizing the following methodology:

Starting Allocation=Σ[A X B_1]+ERCs+External Offsets

Where

A = the throughput for each NO_X and SO_X source or process unit in the facility for the maximum throughput year from 1989 to 1992 inclusive; and

B_1 = the applicable starting emission factor for the subject source or process unit as specified in Table 1 or Table 2

(2) (A) Use of 1992 data is subject to verification and revision by the Executive Officer or designee to assure validity and accuracy.

(B) The maximum throughput year will be determined by the Executive Officer or designee from throughput data reported through annual emissions reports submitted pursuant to Rule 301 - Permit Fees, or may be designated by the permit holder prior to issuance of the Facility Permit.

(C) To determine the applicable starting emission factor in Table 1 or Table 2, the Executive Officer or designee will categorize the equipment at each facility based on information relative to hours of operation, equipment size, heating capacity, and permit information submitted pursuant to Rule 201 - Permit to Construct, and other relevant parameters as determined by the Executive Officer or designee. No information used for purposes of this subparagraph may be inconsistent with any information or statement previously submitted on behalf of the facility to the District, including but not limited to information and statements previously submitted pursuant to Rule 301 - Permit Fees, unless the facility can demonstrate, by clear and convincing documentation, that such information or statement was inaccurate.

(D) Throughput associated with each piece of equipment or NOx or SOx source will be multiplied by the starting emission factors specified in Table 1 or Table 2. If a lower emission factor was utilized for a given piece of equipment or NOx or SOx source pursuant to Rule 301 - Permit Fees, than the factor in Table 1 or

Table 2, the lower factor will be used for determining that portion of the Allocation.

(E) Fuel heating values may be used to convert throughput records into the appropriate units for determining Allocations based on the emission factors in Table 1 or Table 2. If a different unit basis than set forth in Tables 1 and 2 is needed for emissions calculations, the Executive Officer shall use a default heating value to determine source emissions, unless the Facility Permit holder can demonstrate with substantial evidence to the Executive Officer that a different value should be used to determine emissions from that source.

(3) All NO_X and SO_X ERCs generated at the facility and held by a RECLAIM Facility Permit holder shall be reissued as RTCs. RECLAIM facilities will have these RTCs added to their starting Allocations. RTCs generated from the conversion of ERCs shall have a zero rate of reduction for the year 1994 through the year 2000. Such RTCs shall have a cumulative rate of reduction for the years 2001, 2002, and 2003, equal to the percentage inventory adjustment factor applied to 2003 Allocations pursuant to paragraph (e)(1) of this rule and shall have a rate of reduction for compliance year 2004 and subsequent years determined pursuant to paragraph (f)(1) of this rule.

(4) Non-RECLAIM facilities may elect to have their ERCs converted to RTCs and listed on the RTC Listing maintained by the Executive Officer or designee pursuant to Rule 2007 - Trading Requirements, so long as the written request is filed before July 1, 1994. Such RTCs will be assigned to the trading zone in which the generating facility is located. RTCs generated from the conversion of ERCs shall have a zero rate of reduction for the year 1994 through the year 2000. Such RTCs shall have a cumulative rate of reduction for the years, 2001, 2002, and 2003, equal to the percentage inventory adjustment factor applied to 2003 Allocations pursuant to paragraph (e)(1) of this rule.

(5) External offsets provided pursuant to Regulation XIII - New Source Review, not including any offsets in excess of a 1 to 1 ratio, will be added to the starting Allocation pursuant to paragraph (c)(1) provided:

(A) The offsets were not received from either the Community Bank or the Priority Reserve.

(B) External offsets will only be added to the starting Allocation to the extent that the Facility Permit holder demonstrates that they have not already been included in the starting Allocation or as an ERC.

RTCs issued for external offsets shall not include any offsets in excess of a 1 to 1 ratio required under Regulation XIII - New Source Review.

(C) RTCs generated from the conversion of external offsets shall have a zero rate of reduction for the year 1994 through the year 2000. These RTCs shall have a cumulative rate of reduction for the years 2001, 2002, and 2003, equal to the percentage inventory adjustment factor applied to 2003 Allocations pursuant to paragraph (e)(1) of this rule, and for compliance year 2004 and subsequent years allocations shall be determined pursuant to paragraph (f)(1) of this rule. The rate of reduction for the year 2001 through year 2003 shall not be applied to new facilities initially totally permitted on or after January 7, 2005.

(D) Existing facilities with units that have Permits to Construct issued pursuant to Regulation II - Permits, dated on or after January 1, 1992, or existing facilities which have, between January 1, 1992 and October 15, 1993, installed air pollution control equipment that was exempt from offset requirements pursuant to Rule 1304 (a)(5), shall have their starting Allocations increased by the total external offsets provided, or the amount that would have been offset if the exemption had not applied.

(E) Existing facilities with units whose reported emissions are below capacity due to phased construction, and/or where the Permit to Operate issued pursuant to Regulation II - Permits, was issued after January 1, 1992, shall have their starting Allocations increased by the total external offsets provided.

(6) If a Facility Permit holder can demonstrate that its 1994 Allocation is less than the 1992 emissions reported pursuant to Rule 301 - Permit Fees, and that the facility was, in 1992, operating in compliance with all applicable District rules in effect as of December 31, 1993, the facility's starting Allocation will be equal to the 1992 reported emissions.

(7) For new facilities initially totally permitted on or after January 1, 1993 but prior to October 15, 1993, the starting Allocation shall be equal to the external offsets provided by the facility to offset emission increases at the facility pursuant to Regulation XIII - New Source Review, not including any offsets in excess of a 1 to 1 ratio.

(8) The Allocation for new facilities initially totally permitted on and after October 15, 1993, shall be equal to the total RTCs provided by the facility to offset emission increases at the facility pursuant to Rule 2005- New Source Review for RECLAIM.

(9) The starting Allocation for existing facilities which enter the RECLAIM program pursuant to Rule 2001 - Applicability, shall be determined by the methodology in paragraph (c)(1) of this rule. The most recent two years reported emission fee data filed pursuant to Rule 301 - Permit Fees, may be used if 1989 through 1992 emission fee data is not available. For facilities lacking reported emission fee data, the Allocation shall be equal to the external offsets provided pursuant to Regulation XIII - New Source Review, not including any offsets in excess of a 1 to 1 ratio. The Allocation shall not include any emission offsets received from either the Community Bank or the Priority Reserve.

(10) A facility may not receive more than one set of Allocations.

(11) A facility that is no longer holding a valid District permit on January 1, 1994 will not receive an Allocation, but may, if authorized by Regulation XIII, apply for ERCs.

(12) Clean Fuel Adjustment to Starting Allocation

Any refiner who is required to make modifications to comply with CARB Phase II reformulated gasoline production (California Code of Regulations, Title 13, Sections 2250, 2251.5, 2252, 2260, 2261, 2262, 2262.2, 2262.3, 2262.4, 2262.5, 2262.6, 2262.7, 2263, 2264, 2266, 2267, 2268, 2269, 2270, and 2271) or federal requirements (Federal Clean Air Act, Title II, Part A, Section 211; 42 U.S.C. Section 7545) may receive (an) increase(s) in his Allocations except to the extent that there is an increase in maximum rating of the new or modified equipment. Each facility requesting an increase to Allocations shall submit an application for permit amendment specifying the necessary modifications and tentative schedule for completion. The Facility Permit holder shall establish the amount of emission increases resulting from the reformulated gasoline modifications for each year in which the increase in Allocations is requested. The increase to its Allocations will be issued contemporaneously with the modification according to a schedule approved by the Executive Officer or designee (i.e., 1994 through 1997 depending on the refinery). Each increase to the Allocations shall be equal to the increased emissions resulting from the modifications solely to comply with the state or federal reformulated gasoline requirements at the refinery or facility producing hydrogen for reformulated gasoline production, and shall be established according to present and future compliance limits in current District rules or permits. Allocation increases for each refiner pursuant to this paragraph, shall not exceed 5 percent of the refiner's total starting Allocation, unless any refiner emits less than 0.0135 tons of NO_X per thousand barrels of crude processed, in which case the Allocation increases for such refiner shall not exceed 20 percent of that refiner's starting Allocation. The emissions per amount of crude processed will be determined on the basis of information reported to the District pursuant to Rule 301 - Permit Fees, for the same calendar year as the facility's peak activity year for their NO_X starting Allocation.

(d) Establishment of Year 2000 Allocations

(1) (A) The year 2000 Allocations for RECLAIM NO_X and SO_X facilities will be determined by the Executive Officer or designee utilizing the following methodology:

$$\text{Year 2000 Allocation} = \Sigma [A \times B_2] + \text{RTCs created from ERCs} + \text{External Offsets},$$

Where

A = the throughput for each NO_X or SO_X source or process unit in the facility for the maximum throughput year from 1987 to 1992, inclusive, as reported pursuant to Rule 301 - Permit Fees; and

B_2 = the applicable Tier I year Allocation emission factor for the subject source or process unit, as specified in Table 1 or Table 2.

(B) The maximum throughput year will be determined by the Executive Officer or designee from throughput data reported through annual emissions reports pursuant to Rule 301 - Permit Fees, or may be designated by the permit holder prior to issuance of the Facility Permit.

(C) To determine the applicable emission factor in Table 1 or Table 2, the Executive Officer or designee will categorize the equipment at each facility based on information on hours of operation, equipment size, heating capacity, and permit information submitted pursuant to Rule 201 - Permit to Construct, and other parameters as determined by the Executive Officer or designee. No information used for purposes of this subparagraph may be inconsistent with any information or statement previously submitted on behalf of the facility to the District including but not limited to information and statements previously submitted pursuant to Rule 301 - Permit Fees, unless the facility can demonstrate, by clear and convincing documentation, that such information or statement was inaccurate.

(D) Throughput associated with each piece of equipment or NO_X or SO_X source will be multiplied by the Tier I emission factor specified in Table 1 or Table 2. If a factor lower than the factor in Table 1 or Table 2 was utilized for a given piece of equipment or NO_X or SO_X source pursuant to Rule 301, the lower factor will be used for determining that portion of the Allocation.

(E) The fuel heating value may be considered in determining Allocations and will be set to 1.0 unless the Facility Permit holder demonstrates that it should receive a different value.

(F) The year 2000 Allocation is the sum of the resulting products for each piece of equipment or NO_X or SO_X source multiplied by any inventory adjustment pursuant to paragraph (d)(4) of this rule.

(2) For facilities existing prior to October 15, 1993 which enter RECLAIM after October 15, 1993, the year 2000 Allocation will be determined according to paragraph (d)(1). The most recent two years reported emission fee data filed pursuant to Rule 301 - Permit Fees, may be used if 1989 through 1992 emission fee data is not available. For facilities lacking reported emission fee data, the Allocation shall be equal to their external offsets provided pursuant to Regulation XIII - New Source Review, not including any offsets in excess of a 1 to 1 ratio.

(3) No facility shall have a year 2000 Allocation [calculated pursuant to subdivision (d)] greater than the starting Allocation [calculated pursuant to subdivision (c)].

(4) If the sum of all RECLAIM facilities' year 2000 Allocations differs from the year 2000 projected inventory for these sources under the 1991 AQMP, the Executive Officer or designee will establish a percentage inventory adjustment factor that will be applied to adjust each facility's year 2000 Allocation. The inventory adjustment will not apply to RTCs generated from ERCs or external offsets.

(e) Allocations for the Year 2003

(1) The 2003 Allocations will be determined by the Executive Officer or designee applying a percentage inventory adjustment to reduce each facility's

unadjusted year 2000 Allocation so that the sum of all RECLAIM facilities' 2003 Allocations will equal the 1991 AQMP projected inventory for RECLAIM sources for the year 2003, corrected based on actual facility data reviewed for purposes of issuing Facility Permits and to reflect the highest year of actual Basin-wide economic activity for RECLAIM sources considered as a whole during the years 1987 through 1992.

(2) No facility shall have a 2003 Allocation (calculated pursuant this subdivision) greater than the year 2000 Allocation [calculated pursuant to subdivision (d)].

(f) Annual Allocations for NO_X and SOx and Adjustments to RTC Holdings

(1) Allocations for the years between 1994 and 2000, for RECLAIM NO_X and SO_X facilities shall be determined by a straight line rate of reduction between the starting Allocation and the year 2000 Allocation. For the years 2001 and 2002, the Allocations shall be determined by a straight line rate of reduction between the year 2000 and year 2003 Allocations. NOx Allocations for 2004, 2005, and 2006 and SOx Allocations for 2004 through 2012 are equal to the facility's 2003 Allocation, as determined pursuant to subdivision (e). NOx RTC Allocations and holdings subsequent to the year 2006 and SOx Allocations and holdings subsequent to the year 2012 shall be adjusted to the nearest pound as follows:

(A) The Executive Officer will adjust NOx RTC holdings, as of January 7, 2005 for compliance years 2007 and thereafter by multiplying the amount of RTC holdings by the following adjustment factors for the relevant compliance year, to obtain tradable/usable and non-tradable/non-usable holdings:

Compliance Year	Tradable/Usable NOx RTC Adjustment Factor
2007	0.883
2008	0.856
2009	0.829
2010	0.802
2011 and after	0.775

(B) The Executive Officer shall adjust NOx RTCs held as of September 22, 2015 by the RTC holders identified in Table 7 and their successors using the following adjustment factors to obtain Tradable/Usable and Non-Tradable/Non-Usable RTC Holdings:

Compliance Year	Tradable/Usable NOx RTC Adjustment Factor	Non-tradable/ Non-usable NOx RTC Adjustment Factor
2015	1.0	0
2016	0.906	0.094
2017	0.906	0
2018	0.859	0.047
2019	0.812	0.047
2020	0.719	0.093
2021	0.625	0.094
2022	0.437	0.188
2023 and after	0.437	0

RTC holdings traded from RTC holders in Table 7 on and after September 22, 2015 and held by other RTC holders not listed in Table 7 shall be subjected to the above adjustment factors. The adjustment factor(s) for any RTC sold by an RTC holder that both purchased and sold RTCs between September 22, 2015 and December 4, 2015 shall be based on a last in/first out basis.

(C) The Executive Officer shall adjust NOx RTCs held as of September 22, 2015 by the RTC holders identified in Table 8 and their successors using the following adjustment factors to obtain Tradable/Usable and Non-Tradable/Non-Usable RTC holdings:

Compliance Year	Tradable/Usable NOx RTC Adjustment Factor	Non-tradable/ Non-usable NOx RTC Adjustment Factor
2015	1.0	0
2016	0.931	0.069
2017	0.931	0
2018	0.896	0.035
2019	0.861	0.035
2020	0.792	0.069
2021	0.722	0.070
2022	0.583	0.139
2023 and after	0.583	0

RTC holdings traded from RTC holders in Table 8 on and after September 22, 2015 and held by other RTC holders not listed in Table 8 shall be subjected to the above adjustment factors. The adjustment factor(s) for any RTC sold by an RTC holder that both purchased and sold RTCs between September 22, 2015 and December 4, 2015 shall be based on a last in/first out basis.

(D) RTCs designated as non-tradable/non-usable pursuant to subparagraphs (f)(1)(B) and (f)(1)(C) shall be held, but shall not be traded or used for reconciling emissions pursuant to Rule 2004.

(E) Commencing on January 1, 2008 with NOx RTC prices averaged from January 1, 2007 through December 31, 2007, the Executive Officer will calculate the 12-month rolling average RTC price for all trades for the current compliance year. Commencing on May 1, 2016 with NOx RTC prices averaged from January 1, 2016 through March 31, 2016, the Executive Officer will calculate the 3-month rolling average NOx RTC price for all trades for the current compliance year NOx RTCs and the 12-month rolling average NOx RTC price for all trades for infinite year block NOx RTC as defined in subparagraph (f)(1)(I). The Executive Officer will update the 3-month and 12-month rolling average once per month. The computation of the rolling average prices will not include RTC transactions reported at no price or RTC swap transactions.

(F) The Executive Officer shall transfer to a Regional NSR Holding account the amount of NOx RTCs holdings listed in Table 9 of this Rule from the corresponding facilities identified in the same table.

(G) For purposes of meeting the NSR holding requirement as specified in subdivision (f) of Rule 2005, the facilities identified in Table 9 may use a combination of their Tradable/Usable and Non-tradable/Non-usable RTCs specified in subparagraph (f)(1)(C) and the amount listed for each facility in Table 9, which represents the RTCs in the Regional NSR Holding account.

(H) In the event that the NOx RTC prices exceed $22,500 per ton (current compliance year credits) based on the 12-month rolling average, or exceed $35,000 per ton (current compliance year credits) based on the 3-month rolling average calculated pursuant to subparagraph (f)(1)(E), the Executive Officer will report the determination to the Governing Board. If the Governing Board finds that the 12-month rolling average RTC price exceeds $22,500 per ton or the 3-month rolling average RTC price exceeds $35,000 per ton, then the Non-tradable/Non-usable NOx RTCs, as specified in subparagraphs (f)(1)(B) and (f)(1)(C) valid for the period in which the RTC price is found to have exceeded the applicable threshold, shall be converted to Tradable/Usable NOx RTCs upon Governing Board concurrence.

(I) In the event that the infinite year block NOx RTC prices fall below $200,000 per ton based on the 12-month rolling average, calculated pursuant to subparagraph (f)(1)(E) beginning in 2019 for the compliance year in which Cycle 1 facilities are operating, the Executive Officer will report the determination to the Governing Board.

For the purpose of this rule, infinite year block refers to trades involving blocks of RTCs with a specified start year and continuing into the future for ten or more years.

(J) Pursuant to subparagraphs (f)(1)(H) and (f)(1)(I) the Executive Officer's report to the Board will also include a commitment and schedule to conduct a more rigorous control technology implementation, emission reduction, cost-effectiveness, market analysis, and socioeconomic impact assessment of the RECLAIM program. The Executive Officer's report to the Board will be made at a public hearing at the earliest possible regularly scheduled Board Meeting, but no more than 90 days from Executive Officer determination.

(K) The NOx emission reductions associated with the RTC adjustment factors for compliance years 2016, and 2018 through 2022 shall not be submitted for inclusion into the State Implementation Plan until the adjustments have been in effect for one full compliance year. However, the amount of NOx RTCs adjustments specified in sub-paragraph (f)(1)(F) shall not be submitted for inclusion in the State Implementation Plan.

(L) NOx Allocations for existing facilities that enter RECLAIM after December 4, 2015 for Compliance Year 2016 and all subsequent years shall be the amount determined pursuant to subparagraph (d)(1)(A) except the variable B2 shall be the lowest of:

(i) The applicable 2000 (Tier I) Ending Emission Factor for the subject source(s) or process unit(s), as specified in Table 1 multiplied by the percentage inventory adjustment pursuant to subdivision (e) (0.72);

(ii) The BARCT Emission factor for the subject source as specified in Table 3; and

(iii) The BARCT Emission factor for the subject source, as specified in Table 6.

(M) SOx RTC Holdings as of November 5, 2010, for compliance years 2013 and after shall be adjusted to achieve an overall reduction in the following amounts:

Compliance Year	Minimum emission reductions (lbs.)
2013	2,190,000
2014	2,920,000
2015	2,920,000
2016	2,920,000
2017	3,650,000
2018	3,650,000
2019 and after	4,161,000

(N) The Executive Officer shall determine Tradable/usable SOx RTC Adjustment Factor for each compliance year after 2012 as follows:

$$F_{\text{compliance year } i} = 1 - [Xi / (Ai + Bi + Ci)]$$

Where:

$F_{\text{compliance year } i}$ = Tradable/usable SOx RTC Adjustment Factor for compliance year i starting with 2013

Ai = Total SOx RTCs for compliance year i held as of November 5, 2010, by all RTC holders, except those listed in Table 5

Bi = Total SOx RTCs for compliance year i credited to any facilities listed in Table 5 between August 29, 2009 and November 5, 2010, and not included in Ci

Ci = Total SOx RTCs held as of November 5, 2010 by facilities listed in Table 5 for compliance year i in excess of allocations as determined pursuant to subdivision (e).

Xi = Amount to be reduced for compliance year i starting with 2013 as listed in subparagraph (f)(1)(M).

(O) The Executive Officer shall determine Non-tradable/Non-usable SOx RTC Adjustment Factors for compliance years 2017 through 2019 as follows:

$$N_{\text{compliance year } j} = F_{\text{compliance year 2016}} - F_{\text{compliance year } j}$$

Where:

$N_{\text{compliance year } j}$ = Non-tradable/Non-usable SOx RTC Adjustment Factor for compliance year j

$F_{compliance\ year\ j}$ = Tradable/Usable SOx RTC Adjustment Factor for compliance year j as determined pursuant to subparagraph (f)(1)(N)

j = 2017 through 2019

$F_{compliance\ year\ 2016}$ = Tradable/usable SOx RTC Adjustment Factor for compliance year 2016 as determined pursuant to subparagraph (f)(1)(N)

Non-tradable/Non-usable SOx RTC Adjustment Factors for compliance years 2013, 2014, 2020, and all years after 2020 shall be 0.0.

(P) The Executive Officer shall adjust the SOx RTC holdings as of November 5, 2010, for compliance years 2013 and after as follows:

(i) Apply the Tradable/Usable SOx RTC Adjustment Factor ($F_{compliance\ year\ i}$) and Non-tradable/Non-usable SOx RTC Adjustment Factor ($N_{compliance\ year\ j}$) for the corresponding compliance year as published under subparagraph (f)(1)(Q) to SOx RTC holdings held by any RTC holder except those listed in Table 5;

(ii) Apply no adjustment to SOx RTC holdings that are held as of August 29, 2009 by a facility listed in Table 5, and that are less than or equal to the facility's allocations as determined pursuant to subdivision (e), and that were not credited between August 29, 2009 and November 5, 2010;

(iii) Apply the Tradable/Usable SOx RTC Adjustment Factor ($F_{compliance\ year\ i}$) and Non-tradable/Non-usable SOx RTC Adjustment Factor ($N_{compliance\ year\ j}$) for the corresponding compliance year as published under subparagraph (f)(1)(Q) to any SOx RTC holding as of November 5, 2010, that is held by a facility that is listed in Table 5, and that is over the facility's allocations as determined pursuant to subdivision (e); and

(iv) Apply the Tradable/Usable SOx RTC Adjustment Factor ($F_{compliance\ year\ i}$) and Non-tradable/non-usable SOx RTC Adjustment Factor ($N_{compliance\ year\ j}$) for the corresponding compliance year as published under subparagraph (f)(1)(Q) to any SOx RTC holding that was acquired between August 29, 2009 and November 5, 2010, by a facility that is listed in Table 5.

No SOx RTC holding shall be subject to the SOx RTC adjustments as published under subparagraph (f)(1)(Q) more than once.

(Q) The Executive Officer shall publish the SOx RTC Adjustment Factors determined according to subparagraphs (f)(1)(N) and (f)(1)(O) within 30 days after November 5, 2010.

(R) Commencing on January 1, 2017 and ending on February 1, 2020, the Executive Officer will calculate the 12-month rolling average SOx RTC price for all trades during the preceding 12 months for the current compliance year. The Executive Officer will update the 12-month rolling average once per month. The computation of the rolling average prices will not include RTC transactions reported at no price or RTC swap transactions.

(S) In the event that the SOx RTC prices exceed $50,000 per ton based on the 12-month rolling average calculated pursuant to subparagraph (f)(1)(R), the Executive Officer will report to the Governing Board at a duly noticed public hearing to be held no more than 60 days from Executive Officer determination. The Executive Officer will announce that determination on the SCAQMD website. At the public hearing, the Governing Board will decide whether or not to convert any portion of the Non-tradable/Non-usable RTCs, as determined pursuant to subparagraphs (f)(1)(O) and (f)(1)(P), and how much to convert if any, to Tradable/Usable RTCs. The portion of Non-tradable/Non-usable RTCs available for conversion to Tradable/Usable RTCs shall not include any portion of Non-tradable/Non-usable RTCs that are designated for previous compliance years and has not already been converted by the Governing Board, or that has been otherwise included in the State Implementation Plan pursuant to subparagraph (f)(1)(T).

(T) The Executive Officer will not submit the emission reductions obtained through subparagraph (f)(1)(M) for compliance years 2017 through 2019 for inclusion into the State Implementation Plan until the adjustments for the RTC Holdings have been in effect for one full compliance year.

(U) SOx Allocations for compliance years 2013 and after, for facilities that enter RECLAIM after November 5, 2010, and for basic equipment listed in Table 4 shall be determined according to the BARCT level listed in Table 4 or the permitted emission limits, whichever is lower.

(V) By no later than July 1, 2012, SOx emissions at the exhaust of a Fluidized Catalytic Cracking Unit, as measured at the final stack venting gases originating from the facility's FCC Regenerator, including after the CO Boiler or any additional controls in the system following the regenerator (the final stack shall constitute the only exhaust gas compliance point within the FCCU facility), shall not exceed a concentration of 25 ppm dry @ 0% oxygen on a 365-day rolling average. The numeric concentration-based limit does not apply during time periods in which SOx data are determined to be incorrect due to analyzer calibration or malfunction. For the purpose of demonstrating compliance with this limit, the operator of a FCCU shall commence the use of SOx reducing additives in the FCCU no later than July 1, 2011, unless the operator has an existing wet gas scrubber in operation at BARCT levels prior to November 5, 2010 or can demonstrate to the Executive Officer that the FCCU will achieve this limit by using other control methods.

(2) New facilities initially totally permitted, on and after October 15, 1993, but prior to January 7, 2005, and entering the RECLAIM program after January 7, 2005 shall not have a rate of reduction until 2001. Reductions from 2001 to 2003, inclusive, shall be implemented pursuant to subdivision (e). New facilities initially totally permitted on or after January 7, 2005 using external offsets shall have a rate of reduction for such offsets pursuant to subparagraph (c)(5)(C). New facilities initially totally permitted on or after January 7, 2005 using RTCs shall have no rate of reduction for such RTCs, provided that RTCs obtained have been adjusted according to paragraph (f)(1), as applicable. The Facility Permit for such facilities will require the Facility Permit holder to, at the commencement of each compliance year,

hold RTCs equal to the amount of RTCs provided as offsets pursuant to Rule 2005.

(3) Increases to Allocations for permits issued for Clean Fuel adjustments pursuant to paragraph (c)(12), shall be added to each year's Allocation.

(4) During a State of Emergency declared by the Governor related to electricity demand or power grid stability within the SCAQMD jurisdictional boundaries, the current compliance year Non-tradable/Non-usable NOx RTCs held by electricity generating facilities as defined in Rule 2001(g)(1) that generate and distribute electricity to the grid system(s) affected by the State of Emergency may be used to offset their emissions after completely exhausting their own Tradable/Usable NOx RTCs.

If such a facility has completely exhausted their Non-tradable/Non-usable NOx RTCs, the owner or operator of the facility may apply for the use of the NOx RTCs in the Regional NSR Holding Account. The use of such RTCs in this Account shall be based on availability at the end of each quarter. The owner or operator of each electricity generating facility requesting NOx RTCs from the Regional NSR Holding Account shall submit a written request to the Executive Officer specifying the amount of RTCs needed and the basis for requesting the required amount.

The Executive Officer will determine the amount and distribution of the NOx RTCs from the Regional NSR Holding Account based on the requesting facility meeting the following criteria:

(i) The State of Emergency related to electricity demand or power grid stability within the SCAQMD jurisdictional boundaries, as declared by the Governor, was the direct cause of the excess emissions;

(ii) The facility has been ordered to generate electricity in an increased amount and/or frequency due to the State of Emergency;

(iii) The facility has adequately demonstrated their need for the specific amount of RTCs from the Regional NSR Holding Account; and

(iv) The facility owner or operator has not sold any part of their RTC holdings for the subject compliance year.

If the total RTCs requested exceed the supply of RTCs in this Account, the RTCs will be distributed proportionately according to the offset needs of the facilities on a quarterly basis. These RTCs will be non-tradable, but usable to offset emissions.

(5) The Executive Officer will report to the Governing Board within 60 days of the end of the quarter in which a State of Emergency was declared by the Governor related to electricity demand or power grid stability within the SCAQMD jurisdictional boundaries. Included in this report will be, as applicable:

(i) the quantity of RTCs from the Regional NSR Holding Account that were distributed for compliance with the requirement to reconcile quarterly and annual emissions;

(ii) any adverse impacts that the State of Emergency is having on the RECLAIM program; and

(iii) any potential changes to the RECLAIM program that will be needed to help correct these impacts.

(g) High Employment/Low Emissions (HILO) Facility

The Executive Officer or designee will establish a HILO bank funded with the following maximum total annual emission Allocations:

(1) 91 tons per year of NO_X

(2) 91 tons per year of SO_X

(3) After January 1, 1997, new facilities may apply to the HILO bank in order to obtain non-tradable RTCs. Requests will be processed on a first-come, first-served basis, pending qualification.

(4) When credits are available, annual Allocations will be granted for the year of application and all subsequent years.

(5) HILO facilities receiving such Allocations from the HILO bank must verify their HILO status on an annual basis through their APEP report.

(6) Failure to qualify will result in all subsequent years' credits being returned to the HILO bank.

(7) Facilities failing to qualify for the HILO bank Allocations may reapply at any time during the next or subsequent compliance year when credits are available.

(h) Non-Tradable Allocation Credits

(1) Any existing RECLAIM facility with reported emissions pursuant to Rule 301 - Permit Fees, in either 1987, 1988, or 1993, greater than its starting Allocation, shall be assigned non-tradable credits for the first three years of

the program which shall be determined according to the following methodology:

Non-tradable credit for NO_X and SO_X:

Year 1 = (Σ [A X B_1]) - 1994 Allocation;

Where:

A	=	the throughput for each NO_X or SO_X source or process unit in the facility from the single maximum throughput year from 1987, 1988, or 1993; and
B_1	=	the applicable starting emission factor, as specified in Table 1 or Table 2.
Year 2	=	Year 1 non-tradable credits X 0.667
Year 3	=	Year 1 non-tradable credits X 0.333
Year 4 and subsequent years	=	Zero non-tradable credit.

(2) The use of non-tradable credits shall be subject to the following requirements:

(A) Non-tradable credits may only be used for an increase in throughput over that used to determine the facility's starting Allocation. Non-tradable credits may not be used for emissions increases associated with equipment modifications, change in feedstock or raw materials, or any other changes except increases in throughput. The Executive Officer or designee may impose Facility Permit conditions necessary to ensure compliance with this subparagraph.

(B) The use of activated non-tradable credits shall be subject to a non-tradable RTC mitigation fee, as specified in Rule 301 subdivision (n).

(C) In order to utilize non-tradable credits, the Facility Permit holder shall submit a request to the Executive Officer or designee in writing, including a demonstration that the use of the non-tradable credits complies with all requirements of this paragraph, pay any fees required pursuant to Rule 301 - Fees, and have received written approval from the Executive Officer or designee for their use. The Executive Officer or designee shall deny the request unless the Facility Permit holder demonstrates compliance with all requirements of this paragraph. The Executive Officer or designee shall, in writing, approve or deny the request within three business days of submittal of a complete request and notify the Facility Permit holder of the decision. If the request is denied, the Executive Officer or designee will refund the mitigation fee.

(D) In the event that a facility transfers any RTCs for the year in which non-tradable credits have been issued, the non-tradable credit Allocation shall be invalid, and is no longer available to the facility.

(i) NOx RECLAIM Facility Shutdowns

(1) The requirements specified in this subdivision shall be effective October 7, 2016 and only apply to the NOx RECLAIM facilities listed in Tables 7 and 8 of this rule that had a RECLAIM Allocation as issued pursuant to subdivision (b).

(2) An owner or operator of a NOx RECLAIM facility that permanently shuts down or surrenders all operating permits for the entire facility shall notify the Executive Officer in writing of this shutdown within 30 days.

(3) An owner or operator of a NOx RECLAIM facility that shuts down pursuant to paragraphs (i)(2), (i)(8), or (i)(9) shall have its NOx RTC holdings reduced from all future compliance years by an amount equivalent to the difference between:

(A) The average of actual NOx emissions from equipment that is operated at a level greater than the most stringent applicable BARCT emission factors specified in subparagraph (f)(1)(L) during the highest 2 of the past 5 compliance years for the facility; and

(B) The average NOx emissions from the same equipment that would have occurred in those same 2 years identified in subparagraph (i)(3)(A) if the equipment was operated at the most stringent applicable BARCT emission factors specified in subparagraph(f)(1)(L).

(4) Any offsets provided by the SCAQMD pursuant to Rule 1304 that remain as part of the adjusted initial NOx allocation shall also be subtracted for each future compliance year.

(5) If the reduction of NOx RTCs calculated pursuant to paragraph (i)(3) and (i)(4) exceeds the adjusted initial NOx allocation as specified in paragraph (f)(1) for any future compliance year, the facility shall have its NOx holdings reduced by an amount equivalent to the adjusted initial NOx allocation for that compliance year.

(6) If the reduction of NOx RTCs calculated pursuant to paragraphs (i)(3) through (i)(5) exceeds the NOx RTC holdings, within 180 days of notification by the Executive Officer pursuant to paragraph (i)(11), the owner or operator of the NOx RECLAIM facility shall purchase and surrender to

the Executive Officer sufficient RTCs to fulfill the entire reduction requirement.

(7) In addition to a self-reported facility shutdown, the Executive Officer will notify the owner or operator of a NOx RECLAIM facility that the facility is under review as potentially shutdown if NOx emissions from an APEP report show a substantial decrease in facility-wide emissions compared to the maximum emissions during the last five years. Within 60 days of the notification date, the owner or operator shall notify the Executive Officer that the facility is shutdown or submit information to substantiate that the facility is not shutdown based on one the following:

(A) Permanent emission reductions have been implemented at the facility and can be attributed to implementation of an emissions control strategy such as, but not limited to: implementation of pollution control strategies, efficiency improvements, process changes, material substitution, or fuel changes; or

(B) NOx emission reductions are temporary where temporary NOx emission reductions include, but are not limited to: cyclic operations, economic fluctuations, temporary shutdown of equipment due to equipment maintenance, repair, replacement, permitting, compliance, or availability of feedstocks or fuels; or

(C) The owner or operator of a NOx RECLAIM facility has an approved Planned Non-Operational Plan pursuant to paragraph (i)(9).

(8) The Executive Officer will review information submitted under paragraph (i)(7) and notify the owner or operator within 60 days with a determination that the facility has or has not been deemed as shutdown.

(A) If the Executive Officer determines that the NOx RECLAIM facility is deemed shutdown, the owner or operator of the NOx RECLAIM facility shall be subject to the requirements specified in paragraphs (i)(3) through (i)(6).

(B) The Executive Officer will not consider information submitted pursuant to paragraph (i)(7) beyond 60 days of the notification issue date unless such information is subsequently requested by the Executive Officer.

(C) The owner or operator of the NOx RECLAIM facility may file an appeal to the Hearing Board pursuant to paragraph (i)(11).

(9) The owner or operator of the NOx RECLAIM facility may submit a Planned Non-Operational (PNO) Plan, and fees pursuant to Rule 306, to request status

for a non-operational time period beyond 2 years, but no longer than 5 years for equipment within the facility. The Executive Officer will:

(A) Consider the criteria in subparagraph (i)(7)(B) for approving the plan. All of the referenced criteria shall require company records to support the claim that a PNO status of no longer than 5 years is necessary.

(B) Approve or disapprove the PNO Plan within 180 days of receiving a complete PNO Plan.

(i) If the PNO Plan is approved, the owner or operator of the NOx RECLAIM facility may sell current compliance year RTCs for the duration of the approved PNO Plan. Future year NOx RTCs shall become non-tradable for the duration of the PNO status.

(ii) If the PNO Plan is disapproved and the facility is deemed shutdown by the Executive Officer, the owner or operator of the NOx RECLAIM facility shall be subject to the requirements specified in paragraphs (i)(3) through (i)(6).

(iii) The owner or operator of a NOx RECLAIM facility may appeal the denial of PNO Plan to the Hearing Board.

(10) If a NOx RECLAIM facility has been deemed shutdown pursuant to paragraphs (i)(2), (i)(8), or (i)(9), the RTC holdings shall be reduced pursuant to paragraphs (i)(3) through (i)(5).

(11) The Executive Officer will notify the owner or operator of the NOx RECLAIM facility of the amount of reduction in NOx RTC holdings that was determined pursuant to paragraphs (i)(3) through (i)(5). Reduction of NOx RTC holdings shall be applied to RTCs for all future compliance years following this notification. The Executive Officer shall re-issue the facility permit to reflect the reduction of NOx RTC holdings. The owner or operator may file an appeal to the Hearing Board for the shutdown determination and for the reduction in NOx RTC holdings.

(12) The owner or operator of a NOx RECLAIM facility that has notified the Executive Officer of a facility shutdown pursuant to paragraph (i)(2) or has received notification from the Executive Officer that it is under review as potentially shutdown pursuant to paragraph (i)(7), shall not sell any future compliance year RTCs and may only sell current compliance year RTCs until the Executive Officer notifies the owner or operator of the amount of the reduction of NOx RTCs pursuant to paragraph (i)(11).

(13) Any NOx RECLAIM facility under the same ownership as of September 22, 2015 shall submit a written declaration within 30 days after October 7, 2016 identifying the facilities under the same ownership as of September 22, 2015 and a demonstration of how the facilities identified are under the same ownership. For the purposes of this rule, same ownership is generally defined as facilities and their subsidiaries or facilities that share the same Board of Directors or shares the same parent corporation.

(A) The Executive Officer shall maintain a listing of those facilities that are determined to be of same ownership as of September 22, 2015. The Executive Officer will only amend its same ownership listing to exclude those facilities that no longer qualify for same ownership through circumstances such as mergers, sales, or other dispositions.

(B) In the event of a facility reporting a shutdown or is deemed shutdown by the Executive Officer, NOx RTCs from that facility may be transferred to another facility under the same ownership as listed in the most current listing of same ownership without reductions as specified under paragraphs (i)(3) through (i)(6). Such transferred NOx RTCs shall be designated as non-tradable.

Table 1

RECLAIM NO_X Emission Factors

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor *	2000 (Tier I) Ending Ems Factor *
Afterburner (Direct Flame and Catalytic)	Natural Gas	mmcf	130.000	39.000
Afterburner (Direct Flame and Catalytic)	LPG, Propane, Butane	1000 Gal	RV	3.840
Afterburner (Direct Flame and Catalytic)	Diesel	1000 Gal	RV	5.700
Agr Chem-Nitric Acid	Process-Absrbr Tailgas/Nw	tons pure acid produced	RV	1.440
Agricultural Chem - Ammonia	Process	tons produced	RV	1.650
Air Ground Turbines	Air Ground Turbines	(unknown process units)	RV	1.860
Ammonia Plant	Neutralizer Fert, Ammon Nit	tons produced	RV	2.500
Asphalt Heater, Concrete	Natural Gas	mmcf	130.000	65.000
Asphalt Heater, Concrete	Fuel Oil	1000 gals	RV	9.500
Asphalt Heater, Concrete	LPG	1000 gals	RV	6.400
Boiler, Heater R1109 (Petr Refin)	Natural Gas	mmbtu	0.100	0.030
Boiler, Heater R1109 (Petr Refin)	Fuel Oil	mmbtu	0.100	0.030
Boiler, Heater R1146 (Petr Refin)	Natural Gas	mmbtu	0.045	0.045
Boiler, Heater R1146 (Petr Refin)	Fuel Oil	mmbtu	0.045	0.045
Boiler, Heater R1146 (Petr Refin)	Refinery Gas	mmbtu	0.045	0.045
Boilers, Heaters, Steam Gens Rule 1146 and 1146.1	Natural Gas	mmcf	49.180	47.570
Boilers, Heaters, Steam Gens Rule 1146 and 1146.1	LPG, Propane, Butane	1000 gals	4.400	4.260
Boilers, Heaters, Steam Gens Rule 1146 and 1146.1	Diesel Light Dist. (0.05% S)	1000 gals	6.420	6.210
Boilers, Heaters, Steam Gens Rule 1146 and 1146.1	Refinery Gas	mmcf	51.520	49.840
Boilers, Heaters, Steam Gens	Bituminous Coal	tons burned	RV	4.800
Boiler, Heater, Steam Gen (Rule 1146.1)	Natural Gas	mmcf	130.000	39.460
Boiler, Heater, Steam Gen (Rule 1146.1)	Refinery Gas	mmcf	RV	41.340

* RV = Reported Value

** Does not include ceramic, clay, cement or brick kilns or metal melting, heat treating or glass melting furnaces.

*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor *	2000 (Tier I) Ending Ems Factor *
Boiler, Heater, Steam Gen (Rule 1146.1)	LPG, Propane, Butane	1000 gallons	RV	3.530
Boiler, Heater, Steam Gen (Rule 1146.1)	Diesel Light Dist (0.05%)	1000 gallons	RV	5.150
Boiler, Heater, Steam Gen (Rule 1146)	Natural Gas	mmcf	47.750	47.750
Boiler, Heater, Steam Gen (Rule 1146)	Refinery Gas	mmcf	50.030	50.030
Boiler, Heater, Steam Gen (Rule 1146)	LPG, Propane, Butane	1000 gallons	4.280	4.280
Boiler, Heater, Steam Gen (Rule 1146)	Diesel Light Dist (0.05%)	1000 gallons	6.230	6.230
Boiler, Heater, Steam Gen (R1146, <90,000 Therms)	Natural Gas	mmcf	RV	47.750
Boiler, Heater, Steam Gen (R1146, <90,000 Therms)	Refinery Gas	mmcf	RV	50.030
Boiler, Heater, Steam Gen (R1146, <90,000 Therms)	LPG, Propane, Butane	1000 gallons	RV	4.280
Boiler, Heater, Steam Gen (R1146, <90,000 Therms)	Diesel Light Dist (0.05%)	1000 gallons	RV	6.230
Boiler, Heater, Steam Gen (R1146.1, <18,000 Therms)	Natural Gas	mmcf	RV	39.460
Boiler, Heater, Steam Gen (R1146.1, <18,000 Therms)	Refinery Gas	mmcf	RV	41.340
Boiler, Heater, Steam Gen (R1146.1, <18,000 Therms)	LPG, Propane, Butane	1000 gallons	RV	3.530
Boiler, Heater, Steam Gen (R1146.1, <18,000 Therms)	Diesel Light Dist (0.05%)	1000 gallons	RV	5.150
Boiler, Heater R1109 (Petr Refin)	Refinery Gas	mmbtu	0.100	0.030
Boilers, Heaters, Steam Gens, (Petr Refin)	Natural Gas	mmcf	105.000	31.500
Boilers, Heaters, Steam Gens, (Petr Refin)	Refinery Gas	mmcf	110.000	33.000
Boilers, Heaters, Steam Gens, Unpermitted	Natural Gas	mmcf	130.000	32.500
Boilers, Heaters, Steam Gens, Unpermitted	LPG, Propane, Butane	1000 gallons	RV	3.200
Boilers, Heaters, Steam Gens ****	Natural Gas	mmcf	38.460	38.460

* RV = Reported Value

** Does not include ceramic, clay, cement or brick kilns or metal melting, heat treating or glass melting furnaces.

*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor *	2000 (Tier I) Ending Ems Factor *
Boilers, Heaters, Steam Gens ****	Refinery Gas	mmbtu	0.035	0.035
Boilers, Heaters, Steam Gens ****	LPG, Propane, Butane	1000 gallons	3.55	3.55
Boilers, Heaters, Steam Gens ****	Diesel Light Dist (0.05%), Fuel Oil No. 2	mmbtu	0.03847	0.03847
Boilers, Heaters, Steam Gens, Unpermitted	Diesel Light Dist (0.05%)	1000 gallons	RV	4.750
Catalyst Manufacturing	Catalyst Mfg	tons of catalyst produced	RV	1.660
Catalyst Manufacturing	Catalyst Mfg	tons of catalyst produced	RV	2.090
Cement Kilns	Natural Gas	mmcf	130.000	19.500
Cement Kilns	Diesel Light Dist. (0.05% S)	1000 gals	RV	2.850
Cement Kilns	Kilns-Dry Process	tons cement produced	RV	0.750
Cement Kilns	Bituminous Coal	tons burned	RV	4.800
Cement Kilns	Tons Clinker	tons clinker	RV	2.73***
Ceramic and Brick Kilns (Preheated Combustion Air)	Natural Gas	mmcf	213.000	170.400
Ceramic and Brick Kilns (Preheated Combustion Air)	Diesel Light Distillate (.05%)	1000 gallons	RV	24.905
Ceramic and Brick Kilns (Preheated Combustion Air)	LPG	1000 gallons	RV	16.778
Ceramic Clay Mfg	Drying	tons input to process	RV	1.114
CO Boiler	Refinery Gas	mmbtu		0.030
Cogen, Industr	Coke	tons burned	RV	3.682
Electric Generation, Commercial Institutional Boiler	Distillate Oil	1000 gallons	6.420	6.210
Composite Internal Combustion	Waste Fuel Oil	1000 gals burned	RV	31.340
Curing and Drying Ovens	Natural Gas	mmcf	130.000	32.500

* RV = Reported Value

** Does not include ceramic, clay, cement or brick kilns or metal melting, heat treating or glass melting furnaces.

*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor *	2000 (Tier I) Ending Ems Factor *
Curing and Drying Ovens	LPG, Propane, Butane	1000 gals	RV	3.200
Delacquering Furnace	Natural Gas	mmcf	182.2***	182.2***
Fiberglass	Textile-Type Fibr	tons of material processed	RV	1.860
Fluid Catalytic Cracking Unit	Fresh Feed	1000 BBLS fresh feed	RV	RV*0.3 ***
Fluid Catalytic Cracking Unit with Urea Injection	Fresh Feed	1000 BBLS fresh feed	RV	(RV*0.3) / (1-control efficiency) ***
Fugitive Emission	Not Classified	tons product	RV	0.087
Furnace Process	Carbon Black	tons produced	RV	38.850
Furnace Suppressor	Furnace Suppressor	unknown	RV	0.800
Glass Fiber Furnace	Mineral Products	tons product produced	RV	4.000
Glass Melting Furnace	Flat Glass	tons of glass pulled	RV	4.000
Glass Melting Furnace	Tableware Glass	tons of glass pulled	RV	5.680
Glass Melting Furnaces	Container Glass	tons of glass produced	4.000	1.2***
ICEs****	All Fuels		Equivalent to permitted BACT limit	Equivalent to permitted BACT limit
ICEs, Permitted (Rule 1110.1 and 1110.2)	Natural Gas	mmcf	2192.450	217.360
ICEs Permitted (Rule 1110.2)	Natural Gas	mmcf	RV	217.360
ICEs, Permitted (Rule 1110.1 and 1110.2)	LPG, Propane, Butane	1000 gals	RV	19.460
ICEs, Permitted (Rule 1110.1 and 1110.2)	Gasoline	1000 gals	RV	20.130
ICEs, Permitted (Rule 1110.1 and 1110.2)	Diesel Oil	1000 gals	RV	31.340
ICEs, Exempted per Rule 1110.2	All Fuels		RV	RV
ICEs, Exempted per Rule 1110.2 and subject to Rule 1110.1	All Fuels		RV	RV
ICEs, Unpermitted	All Fuels		RV	RV
In Process Fuel	Coke	tons burned	RV	24.593
Incinerators	Natural Gas	mmcf	130.000	104.000
Industrial	Propane	1000 gallons	RV	20.890
Industrial	Gasoline	1000 gallons	RV	21.620

* RV = Reported Value

** Does not include ceramic, clay, cement or brick kilns or metal melting, heat treating or glass melting furnaces.

*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor*	2000 (Tier I) Ending Ems Factor *
Industrial	Dist.Oil/Diesel	1000 gallons	RV	33.650
Inorganic Chemicals, H2SO4 Chamber	General	tons pure acid produced	RV	0.266
Inorganic Chemicals, H2SO4 Contact	Absrbr 98.0% Conv	tons 100% H2S04	RV	0.376
Iron/Steel Foundry	Steel Foundry, Elec Arc Furn	tons metal processed	RV	0.045
Metal Heat Treating Furnace	Natural Gas	mmcf	130.000	104.000
Metal Heat Treating Furnace	Diesel Light Distillate (.05%)	1000 gallons	RV	15.200
Metal Heat Treating Furnace	LPG	1000 gallons	RV	10.240
Metal Forging Furnace (Preheated Combustion Air)	Natural Gas	mmcf	213.000	170.400
Metal Forging Furnace (Preheated Combustion Air)	Diesel Light Distillate (.05%)	1000 gallons	RV	24.905
Metal Forging Furnace (Preheated Combustion Air)	LPG	1000 gallons	RV	16.778
Metal Melting Furnaces	Natural Gas	mmcf	130.000	65.000
Metal Melting Furnaces	LPG, Propane, Butane	1000 gals	RV	6.400
Miscellaneous		bbls-processed	RV	1.240
Natural Gas Production	Not Classified	mmcf gas	RV	6.320
Nonmetallic Mineral	Sand/Gravel	tons product	RV	0.030
NSPS	Refinery Gas	mmbtu	RV	0.030
Other BACT Heater (24F-1)	Natural Gas	mmcf	RV	RV
Other Heater (24F-1)	Pressure Swing Absorber Gas	mmcf	RV	RV
Ovens, Kilns, Calciners, Dryers, Furnaces**	Natural Gas	mmcf	130.000	65.000
Ovens, Kilns, Calciners, Dryers, Furnaces**	Diesel Light Dist. (0.05% S)	1000 gals	RV	9.500
Paint Mfg, Solvent Loss	Mixing/Blending	tons solvent	RV	45.600
Petroleum Refining	Asphalt Blowing	tons of asphalt produced	RV	45.600
Petroleum Refining, Calciner	Petroleum Coke	Calcined Coke	RV	0.971***
Plastics Prodn	Polyester Resins	tons product	RV	106.500
Pot Furnace	Lead Battery	lbs Niter	0.077***	0.062***
Process Specific	ID# 012183	(unknown process units)	RV	240.000
Process Specific	SCC 30500311	tons produced	RV	0.140

* RV = Reported Value

** Does not include ceramic, clay, cement or brick kilns or metal melting, heat treating or glass melting furnaces.

*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor*	2000 (Tier I) Ending Ems Factor *
Process Specific	ID 14944	(unknown process units)	RV	0.512
SCC 39090003			RV	170.400
Sec. Aluminum	Sweating Furnace	tons produced	RV	0.300
Sec. Aluminum	Smelting Furnace	tons metal produced	RV	0.323
Sec. Aluminum	Annealing Furnace	mmcf	130.000	65.000
Sec. Aluminum	Boring Dryer	tons produced	RV	0.057
Sec. Lead	Smelting Furnace	tons metal charged	RV	0.110
Sec. Lead	Smelting Furnace	tons metal charged	RV	0.060
Sodium Silicate Furnace	Water Glass	Tons Glass Pulled	RV	6.400
Steel Hot Plate Furnace	Natural Gas	mmcf	213.000	106.500
Steel Hot Plate Furnace	Diesel Light Distillate (.05%)	1000 gallons	31.131	10.486
Steel Hot Plate Furnace	LPG, Propane, Butane	1000 gallons	20.970	10.486
Surface Coal Mine	Haul Road	tons coal	RV	62.140
Tail Gas Unit		hours of operation	RV	RV
Turbines	Butane	1000 Gallons	RV	5.700
Turbines	Diesel Oil	1000 gals	RV	8.814
Turbines	Refinery Gas	mmcf	RV	62.275
Turbines	Natural Gas	mmcf	RV	61.450
Turbines (micro-)	Natural Gas	mmcf	54.4	54.4
Turbines - Peaking Unit	Natural Gas	mmcf	RV	RV
Turbines - Peaking Unit	Dist. Oil/Diesel	1000 gallons	RV	RV
Utility Boiler	Digester/Landfill Gas	mmcf	52.350	10.080
Turbine	Natural Gas	mmcf	RV	61.450
Turbine	Fuel Oil	1000 gallons	RV	8.810
Turbine	Dist.Oil/Diesel	1000 gallons	RV	3.000
Utility Boiler Burbank	Natural Gas	mmcf	148.670	17.200
Utility Boiler Burbank	Residual Oil	1000 gallons	20.170	2.330
Utility Boiler, Glendale	Natural Gas	mmcf	140.430	16.000
Utility Boiler, Glendale	Residual Oil	1000 gallons	20.160	2.290
Utility Boiler, LADWP	Natural Gas	mmcf	86.560	15.830
Utility Boiler, LADWP	Residual Oil	1000 gallons	12.370	2.260
Utility Boiler, LADWP	Digester Gas	mmcf	52.350	10.080
Utility Boiler, LADWP	Landfill Gas	mmcf	37.760	6.910
Utility Boiler, Pasadena	Natural Gas	mmcf	195.640	18.500
Utility Boiler, Pasadena	Residual Oil	1000 gallons	28.290	2.670
Utility Boiler, SCE	Natural Gas	mmcf	74.860	15.600
Utility Boiler, SCE	Residual Oil	1000 gallons	10.750	2.240

* RV = Reported Value

** Does not include ceramic, clay, cement or brick kilns or metal melting, heat treating or glass melting furnaces.

*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Table 2

RECLAIM SO_X Emission Factors

Sulfur Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Emission Factor *	Ending Emission Factor *
Air Blown Asphalt		hours of operation	RV	RV
Asphalt Concrete	Cold Ag Handling	tons produced	RV	0.032
Calciner	Petroleum Coke	Calcined Coke	RV	0.000
Catalyst Regeneration		hours of operation	RV	RV
Cement Kiln	Distillate Oil	1000 gallons	RV	RV
Cement Mfg	Kilns, Dry Process	tons produced	RV	RV
Claus Unit		pounds	RV	RV
Cogen	Coke	pounds per ton	RV	RV
Non Fuel Use		hours of operation	RV	RV
External Combustion Equipment / Incinerator	Natural Gas	mmcf	RV	0.830
External Combustion Equip/Incinerator	LPG, Propane, Butane	1000 gallons	RV	4.600
External Combustion Equip/Incinerator	Diesel Light Dist. (0.05% S)	1000 gallons	7.00	5.600
External Combustion Equip/Incinerator	Residual Oil	1000 gallons	8.00	6.400
External Combustion Equip/Incinerator	Refinery Gas	mmcf	RV	6.760
Fiberglass	Recuperative Furn, Textile-Type Fiber	tons produced	RV	2.145
Fluid Catalytic Cracking Units		1000 bbls refinery feed	RV	13.700
Glass Mfg, Forming/Fin	Container Glass		RV	RV
Grain Milling	Flour Mill	tons Grain Processed	RV	RV
ICEs	Natural Gas	mmcf	RV	0.600
ICEs	LPG, Propane, Butane	1000 gallons	RV	0.350
ICEs	Gasoline	1000 gallons	RV	4.240
ICEs	Diesel Oil	1000 gallons	6.24	4.990
Industrial	Cogeneration, Bituminous Coal	tons produced	RV	RV
Industrial (scc 10200804)	Cogeneration, Coke	tons produced	RV	RV
Inorganic Chemcals	General, H2SO4 Chamber	tons produced	RV	RV
Inorganic Chemcals	Absrbr 98.0% Conv, H2SO4 Contact	tons produced	RV	RV

* RV = Reported Value

*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

Sulfur Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Emission Factor *	Ending Emission Factor *
Inprocess Fuel	Cement Kiln/Dryer, Bituminous Coal	tons produced	RV	RV
Iron/Steel Foundry	Cupola, Gray Iron Foundry	tons produced	RV	0.720
Melting Furnace, Container Glass		tons produced	RV	RV
Mericher Alkyd Feed		hours of operation	RV	RV
Miscellaneous	Not Classified	tons produced	RV	0.080
Miscellaneous	Not Classified	tons produced	RV	0.399
Natural Gas Production	Not Classified	mmcf	RV	527.641
Organic Chemical (scc 30100601)		tons produced	RV	RV
Petroleum Refining (scc30600602)	Column Condenser		RV	1.557
Petroleum Refining (scc30600603)	Column Condenser		RV	1.176
Refinery Process Heaters	LPG fired	1000 gal	RV	2.259
Pot Furnace	Lead Battery	lbs Sulfur	0.133***	0.106***
Sec. Lead	Reverberatory, Smelting Furnace	tons produced	RV	RV
Sec. Lead	Smelting Furnace, Fugitiv	tons produced	RV	0.648
Sour Water Oxidizer		hours of operation	RV	RV
Sulfur Loading		1000 bbls	RV	RV
Sour Water Oxidizer		1000 bbls fresh feed	RV	RV
Sour Water Coker		1000 bbls fresh feed	RV	RV
Sodium Silicate Furnace		tons of glass pulled	RV	RV
Sulfur Plant		hours of operation	RV	RV
Tail gas unit		hours of operation	RV	RV
Turbines	Refinery Gas	mmcf	RV	6.760
Turbines	Natural Gas	mmcf	RV	0.600
Turbines	Diesel Oil	1000 gal	6.24	0.080
Turbines	Residual Oil	1000 gallons	8.00	0.090
Utility Boilers	Diesel Light Dist. (0.05% S)	1000 gallons	7.00	0.080
Utility Boilers	Residual Oil	1000 gallons	8.00	0.090
Other Heater (24F-1)	Pressure Swing Absorber Gas	mmcf	RV	RV

* RV = Reported Value

*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

Table 3

RECLAIM NO_X 2011 Ending Emission Factors

Nitrogen Oxides Basic Equipment	BARCT Emission Factor
Asphalt Heater, Concrete	0.036 lb/mmbtu (30 ppm)
Boiler, Heater R1109 (Petr Refin) >110 mmbtu/hr	0.006 lb/mmbtu (5 ppm)
Boilers, Heaters, Steam Gens, (Petr Refin) >110 mmbtu/hr	0.006 lb/mmbtu (5 ppm)
Boiler, Heater, Steam Gen (Rule 1146.1) 2-20 mmbtu/hr	0.015 lb/mmbtu (12 ppm)
Boiler, Heater, Steam Gen (Rule 1146) >20 mmbtu/hr	0.010 lb/mmbtu (9 ppm)
CO Boiler	85% Reduction
Delacquering Furnace	0.036 lb/mmbtu (30 ppm)
Fluid Catalytic Cracking Unit	85% Reduction
Iron/Steel Foundry	0.055 lb/mmbtu (45 ppm)
Metal Heat Treating Furnace	0.055 lb/mmbtu (45 ppm)
Metal Forging Furnace (Preheated Combustion Air)	0.055 lb/mmbtu (45 ppm)
Metal Melting Furnaces	0.055 lb/mmbtu (45 ppm)
Other Heater (24F-1)	0.036 lb/mmbtu (30 ppm)
Ovens, Kilns, Calciners, Dryers, Furnaces	0.036 lb/mmbtu (30 ppm)
Petroleum Refining, Calciner	0.036 lb/mmbtu (30 ppm)
Sec. Aluminum	0.055 lb/mmbtu (45 ppm)
Sec. Lead	0.055 lb/mmbtu (45 ppm)
Steel Hot Plate Furnace	0.055 lb/mmbtu (45 ppm)
Utility Boiler	0.008 lb/mmbtu (7 ppm)

Table 4
RECLAIM SOx Tier III Emission Standards

Basic Equipment	BARCT Emission Standard
Calciner, Petroleum Coke	10 ppmv (0.11 lbs/ton coke)
Cement Kiln	5 ppmv (0.04 lbs/ton clinker)
Coal-Fired Boiler	5 ppmv (95% reduction)
Container Glass Melting Furnace	5 ppmv (0.03 lbs/ton glass)
Diesel Combustion	15 ppm by weight as required under Rule 431.2
Fluid Catalytic Cracking Unit	5 ppmv (3.25 lbs/thousand barrels feed)
Refinery Boiler/Heater	40 ppmv (6.76 lbs/mmscf)
Sulfur Recovery Units/Tail Gas	5 ppmv for combusted tail gas (5.28 lbs/hour)
Sulfuric Acid Manufacturing	10 ppmv (0.14 lbs/ton acid produced)

Table 5
List of SOx RECLAIM Facilities Referenced in Subparagraphs (f)(1)(M) and (f)(1)(O)

FACILITY PERMIT HOLDER	AQMD ID NO.
AES HUNTINGTON BEACH, LLC*	115389
AIR LIQUIDE LARGE INDUSTRIES U.S., LP	148236
ANHEUSER-BUSCH INC., (LA BREWERY)	16642
CALMAT CO	119104
CENCO REFINING CO	800373
EDGINGTON OIL COMPANY	800264
EQUILON ENTER. LLC, SHELL OIL PROD. US	800372
EXIDE TECHNOLOGIES	124838
INEOS POLYPROPYLENE LLC	124808
KIMBERLY-CLARK WORLDWIDE INC.-FULT. MILL	21887
LUNDAY-THAGARD COMPANY	800080
OWENS CORNING ROOFING AND ASPHALT, LLC	35302
PABCO BLDG PRODUCTS LLC,PABCO PAPER, DBA	45746
PARAMOUNT PETR CORP*	800183
QUEMETCO INC	8547
RIVERSIDE CEMENT CO	800182
TECHALLOY CO., INC.	14944
TESORO REFINING AND MARKETING CO*	151798
THE PQ CORP	11435
US GYPSUM CO	12185
WEST NEWPORT OIL CO	42775

* SOx RECLAIM facilities that have RTC Holdings larger than initial allocations as of August 29, 2009.

Table 6

RECLAIM NO_X 2022 Ending Emission Factors

Nitrogen Oxides Basic Equipment	BARCT Emission Factor
Boiler, Heater R1109 (Petr Refin) >40 mmbtu/hr	2 ppm
Cement Kilns	0.5 lbs per ton clinker
Fluid Catalytic Cracking Unit	2 ppm
Gas Turbines	2 ppm
Glass Melting Furnaces – Container Glass	80% reduction (0.24 lb/ton glass produced)
ICEs, Permitted (Rule 1110.2) (Non-OCS)	11 ppm @15%O_2 0.041 lb/MMBTU 43.05 lb/mmcf
Metal Heat Treating Furnace >150 mmbtu/hr	0.011 lb/mmbtu (9 ppm)
Petroleum Refining, Calciner	10 ppm
Sodium Silicate Furnace	80% reduction (1.28 lb/ton glass pulled)
SRU/Tail Gas Unit	95% reduction 2ppm

Table 7

List of NOx RECLAIM Facilities Referenced in Subparagraph (f)(1)(B)

FACILITY PERMIT HOLDER	AQMD ID NO.
CHEVRON PRODUCTS CO.	800030
EXXONMOBIL OIL CORPORATION	800089
PHILLIPS 66 CO/LA REFINERY WILMINGTON PL	171107
PHILLIPS 66 COMPANY/LOS ANGELES REFINERY	171109
TESORO REF & MKTG CO LLC,CALCINER	174591
TESORO REFINING & MARKETING CO, LLC	174655
TESORO REFINING AND MARKETING CO, LLC	151798
TESORO REFINING AND MARKETING CO, LLC	800436
ULTRAMAR INC	800026
NOx RTC holders not designated as Facility Permit Holders as of September 22, 2015, except any NOx RTC holders listed in Table 8	Multiple

Table 8
List of NOx RECLAIM Facilities Referenced in Subparagraph (f)(1)(C)

FACILITY PERMIT HOLDER	AQMD ID NO.
AES ALAMITOS, LLC	115394
AES HUNTINGTON BEACH, LLC	115389
AES REDONDO BEACH, LLC	115536
BERRY PETROLEUM COMPANY	119907
BETA OFFSHORE	166073
BICENT (CALIFORNIA) MALBURG LLC	155474
BORAL ROOFING LLC	1073
BURBANK CITY, BURBANK WATER & POWER	25638
BURBANK CITY,BURBANK WATER & POWER,SCPPA	128243
CALIFORNIA PORTLAND CEMENT CO	800181
CALIFORNIA STEEL INDUSTRIES INC	46268
CANYON POWER PLANT	153992
CPV SENTINEL LLC	152707
DISNEYLAND RESORT	800189
EDISON MISSION HUNTINGTON BEACH, LLC	167432
EL SEGUNDO POWER, LLC	115663
EXIDE TECHNOLOGIES	124838
GENERAL ELECTRIC COMPANY	700126
HARBOR COGENERATION CO, LLC	156741
INLAND EMPIRE ENERGY CENTER, LLC	129816
LA CITY, DWP HAYNES GENERATING STATION	800074
LA CITY, DWP SCATTERGOOD GENERATING STN	800075
LA CITY, DWP VALLEY GENERATING STATION	800193
LONG BEACH GENERATION, LLC	115314
NEW- INDY ONTARIO, LLC	172005
NRG CALIFORNIA SOUTH LP, ETIWANDA GEN ST	115315
OWENS-BROCKWAY GLASS CONTAINER INC	7427
OXY USA INC	169754
PACIFIC CLAY PRODUCTS INC	17953
PARAMOUNT PETR CORP	800183
PASADENA CITY, DWP	800168
PQ CORPORATION	11435
QUEMETCO INC	8547
SAN DIEGO GAS & ELECTRIC	4242
SNOW SUMMIT INC	43201
SO CAL EDISON CO	4477
SO CAL GAS CO	800128
SO CAL GAS CO	800127
SO CAL GAS CO	5973
SO CAL GAS CO/PLAYA DEL REY STORAGE FACI	8582
SOLVAY USA, INC.	114801

FACILITY PERMIT HOLDER	AQMD ID NO.
SOUTHERN CALIFORNIA EDISON	160437
TABC, INC	3968
TAMCO	18931
US GOVT, NAVY DEPT LB SHIPYARD	800153
WALNUT CREEK ENERGY, LLC	146536
WHEELABRATOR NORWALK ENERGY CO INC	51620
WILDFLOWER ENERGY LP/INDIGO GEN., LLC	127299

Table 9
List of NOx RECLAIM Facilities for the Regional NSR Holding Account with Balances (in lbs)

FACILITY PERMIT HOLDER	AQMD ID NO.	2016		2017		2018		2019		2020		2021		2022		2023+	
		Dec 2016	Jun 2017	Dec 2017	Jun 2018	Dec 2018	Jun 2019	Dec 2019	Jun 2020	Dec 2020	Jun 2021	Dec 2021	Jun 2022	Dec 2022	Jun 2023	Dec 2023+	Jun 2023+
BICENT (CALIFORNIA) MALBURG LLC	155474	0	0	1,854	1,854	1,854	1,854	2,794	2,794	3,735	3,734	5,588	5,588	7,469	7,469	11,204	11,203
BURBANK CITY, BURBANK WATER & POWER, SCPPA	128243	0	0	1,604	5,159	1,604	5,159	2,418	7,775	3,232	10,392	4,836	15,551	6,464	20,784	9,695	31,177
CANYON POWER PLANT	153992	0	0	3,248	2,548	3,248	2,548	4,896	3,840	6,543	5,133	9,792	7,680	13,087	10,265	19,630	15,398
CPV CENTINEL LLC	152707	0	0	9,645	6,981	9,645	6,981	14,538	10,522	19,430	14,063	29,075	21,044	38,860	28,127	58,290	42,190
GENERAL ELECTRIC COMPANY/INLAND EMPIRE ENERGY CENTER	700126/ 129816	0	0	9,065	6,573	9,065	6,573	13,664	9,907	18,262	13,241	27,327	19,815	36,524	26,484	54,785	39,725
LONG BEACH GENERATION, LLC	115314	0	0	0	5,962	0	5,962	0	8,986	0	12,010	0	17,971	0	24,019	0	36,029
SOUTHERN CALIFORNIA EDISON	160437	0	0	13,227	6,758	13,227	6,758	19,937	10,184	26,646	13,612	39,874	20,370	53,293	27,225	79,940	40,837
WALNUT CREEK ENERGY, LLC	146536	0	0	3,690	4,242	3,690	4,242	5,562	6,393	7,434	8,544	11,124	12,786	14,867	17,089	22,301	25,633
WILDFLOWER ENERGY LP/INDIGO GEN., LLC	127299	0	0	0	3,483	0	3,483	0	5,250	0	7,016	0	10,499	0	14,033	0	21,049

(Adopted October 15, 1993)(Amended December 7, 1995)(Amended July 12, 1996)
(Amended May 11, 2001)(Amended April 6, 2007)

RULE 2004. REQUIREMENTS

(a) Purpose

The purpose of this rule is to establish the requirements for operating under the RECLAIM program. The rule includes provisions pertaining to permits, Allocations, reporting, variances, and breakdowns.

(b) Compliance Period and Certification of Emissions

(1) The compliance year shall be divided into four quarters for emission reporting and certification purposes. The 30 calendar days after the conclusion of each of the first three quarters shall be a reconciliation period. During the reconciliation period, the Facility Permit holder shall calculate the facility's total emissions for the quarter, acquire and have credited to the facility, pursuant to Rule 2007 - Trading Requirements and Rule 2020 – RECLAIM Reserve, any RTCs necessary to reconcile the Allocation to the emissions, and except as provided under paragraph (b)(6), submit to the Executive Officer a Quarterly Certification of Emissions. In addition, to reconcile the Allocation to the emissions, power producing facilities may utilize the Mitigation Fee Program specified in subdivision (o) of this rule.

(2) The Quarterly Certification of Emissions shall be made in the manner and form specified by the Executive Officer and shall be certified for accuracy by the highest ranking management official with responsibility for operation of equipment subject to the Facility Permit, except as provided under paragraph (b)(6). The Quarterly Certification of Emissions shall be calculated as required by Rules 2011 - Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Sulfur (SO_X) Emissions, and 2012 - Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Nitrogen (NO_X) Emissions, and Facility Permit conditions applicable to the facility.

(3) Upon receipt of the certified Quarterly Report, the Executive Officer will debit the RTC Listing for the submitting facility by the amount certified in the report.

(4) The 60 calendar days following the last day of each compliance year shall be the reconciliation period for the last quarter. On or before the last day of such reconciliation period, the Facility Permit holder shall calculate the facility's total emissions for the last quarter, acquire and have credited to the facility, pursuant to Rule 2007 and Rule 2020, any RTCs necessary to reconcile the Allocations to the emissions, and except as provided under paragraph (b)(6), submit an Annual Permit Emissions Program (APEP) report, as prescribed by the Executive Officer, for the purpose of compliance reporting, permit review, and determination of fees. As part of the APEP report, the Facility Permit holder shall accurately report the information specified in Rule 2015 subparagraph (b)(1)(C), (b)(1)(D), and (b)(1)(H) for the District's annual audit.

(5) Except as provided in subdivision (c), the reconciliation period following the end of a quarter shall be used to reconcile the Allocation only with emissions from that quarter.

(6) The Facility Permit holder of a facility that does not have any NOx or SOx emitting sources located at the facility (including, but not limited to, permitted equipment, non-permitted equipment pursuant to Rule 219, rental or leased equipment, or equipment operated by contractors) shall not be required to submit Quarterly Certification of Emissions pursuant to paragraphs (b)(1) and (b)(2) and APEP reports pursuant to paragraph (b)(4) provided that the Facility Permit holder:

(A) submits an application for permit amendment;

(B) demonstrates to the satisfaction of the Executive Officer that there are no NOx or SOx sources located at the facility; and

(C) receives an amended Facility Permit containing permit conditions to ensure that there are no NOx or SOx emissions from the facility at all times.

(7) A Facility Permit holder which has submitted an application for permit amendment pursuant to paragraph (b)(6) for exemption from the reporting requirements of paragraphs (b)(1), (b)(2), and (b)(4) shall not locate or operate NOx or SOx sources at the facility unless such application has been cancelled or denied or the permit has been amended to allow construction and operation of NOx or SOx sources. Once the Executive Officer has issued a permit amendment allowing construction and operation of a NOx or SOx source, the facility shall no longer be exempt

under this paragraph. If the Facility Permit holder is found in violation of any permit condition issued pursuant to paragraph (b)(6), the facility shall be assessed a single separate violation of this rule for each source and each day the source was on the premises. For purposes of determining emissions from each violating source, on each and every day that the source was on the premises, emissions shall be calculated assuming the source was uncontrolled and operated at maximum capacity for 24 hours a day.

(c) Correction of Quarterly Certification of Emissions

(1) The Facility Permit holder may, at any time prior to the end of the reconciliation period for the last quarter of the compliance year, make corrections to any quarterly certification of emissions, provided that the Facility Permit holder demonstrates that:

(A) emissions were inaccurately certified due to an error caused by conditions beyond the reasonable control of the Facility Permit holder; and

(B) the corrected information is accurate; and

(C) the Facility Permit holder has made the correction within thirty days of discovering the error necessitating the correction or within thirty days of when the error reasonably could have been discovered, whichever is earlier.

(2) If a correction is made to a Quarterly Certification of Emissions:

(A) the certification requirements set forth in paragraph (b)(2) shall apply to the correction; and

(B) the RTC Listing will be amended to show the corrected amount.

(C) the Facility Permit holder shall, within 30 days of the correction of the Quarterly Certification of Emission, but no later than the end of the reconciliation period for the last quarter, acquire any RTCs as necessary pursuant to Rule 2007 and Rule 2020 to reconcile the Allocation to the revised certification, and for a Facility Permit holder of a Power Producing Facility, comply with subdivision (o) of this rule.

(d) Prohibition of Emissions in Excess of Annual Allocation

(1) Emissions from a RECLAIM facility from the beginning of a compliance year through the end of any quarter shall not exceed the annual emissions Allocation in effect at the end of the applicable reconciliation period for such quarter. Except as provided in paragraph (d)(2), or subdivision (o), any such emissions in excess of the Allocation shall constitute a single, separate violation of this rule for each day of the compliance year (365 days).

(2) In the event of a violation of paragraph (d)(1), the Facility Permit holder may, pursuant to this paragraph, establish a number of violations less than that set forth in paragraph (d)(1) above. The number of violations under this paragraph shall be the number of days or portion thereof, during which any source of the subject RECLAIM pollutant operated after the Allocation was exceeded, plus one violation for each 1,000 pounds, or portion thereof, emitted in excess of the Allocation. In order to establish the number of violations under this paragraph, the Facility Permit holder shall have the burden of establishing the number of days, or such lesser period as can be established, that the cumulative facility emissions were less than the annual emission Allocation. If the Facility Permit holder is not able to establish the number of days or period during which the cumulative facility emissions were less than the annual emission Allocation, the facility shall be in violation pursuant to paragraph (d)(1) of this rule.

(3) If the average annual price of RTCs exceeds $8,000 dollars per ton then for purposes of paragraph (d)(2) of this rule, one violation per 500 pounds or portion thereof, of excess emissions shall be used in lieu of one violation per 1,000 pounds or a portion thereof, of excess emissions. The average annual price of RTCs will be the price most recently determined pursuant to Rule 2015 (b)(1)(E).

(4) For purposes of this rule, emissions from the facility shall be determined solely pursuant to methods and procedures specified in Regulation XX - Regional Clean Air Incentives Market (RECLAIM) and the Facility Permit, if applicable.

(e) Prohibition of Submission of an Inaccurate Quarterly Certification of Emissions

(1) Any Quarterly Certification of Emissions determined by the Executive Officer to be inaccurate, shall constitute a violation of this rule, unless the report was corrected by the Facility Permit holder in accordance with the requirements of paragraph (c)(1).

(2) A violation of this subdivision shall constitute a single, separate violation of this rule for each day in the quarter.

(f) Permit Requirements

(1) The Facility Permit holder shall, at all times, comply with all rules and permit conditions applicable to the facility, as specified in the Facility Permit.

(2) A person shall not build, erect or install a new source or a modification as defined in Rule 2000 - General, without first complying with Rule 201 - Permit to Construct.

(g) Emissions in Excess of a Concentration Limit

(1) In the event emissions exceed a concentration limit, as established by a source test, the days of violation shall be presumed to include the date of the source test and each and every day thereafter until the Facility Permit holder establishes that continuous compliance has been achieved, except to the extent the Facility Permit holder can prove that there were intervening days during which no violation occurred or that the violation was not continuing in nature.

(2) In the event emissions exceed a concentration limit, as established by a source test, the emissions from the source to which the concentration limit applies shall be calculated using the higher concentration for purposes of determining compliance with the facility's Allocation until the Facility Permit holder demonstrates that it is in compliance with the concentration limit set forth in the Facility Permit.

(h) Federal Requirements for the Use of Clean Fuels or Advanced Control Technology

Effective November 15, 1998, each new, modified, and existing electric utility and industrial and commercial boiler which emits more than 25 tons per year of Oxides of Nitrogen shall:

(1) burn as its primary fuel natural gas, methanol, or ethanol (or a comparably low polluting fuel); or

(2) use advanced control technology, such as catalytic control technology or other comparably effective control methods, for reduction of emissions of Oxides of Nitrogen.

For purposes of paragraph (h)(1), the term "primary fuel" means the fuel which is used 90 percent or more of the operating time. This subdivision shall not apply during any natural gas supply emergency as defined in Title III of the Natural Gas Policy Act of 1978.

(i) Breakdown Provisions

(1) Reporting Requirements

(A) The Facility Permit holder shall report any breakdown which results in:

(i) a violation of any rule or permit condition not specified in subparagraph (i)(2)(B); or

(ii) a request of excess emissions not be counted in determining compliance with the RECLAIM facility's annual allocations.

Such breakdown shall be reported by telephone, or other District-approved method to the Executive Officer within one hour of such breakdown or within one hour of the time the Facility Permit holder knew or reasonably should have known of its occurrence. Such report shall identify the time, specific location, equipment involved, responsible party to contact for further information, and to the extent known, the causes of the breakdown and the estimated time for repairs. In the case of emergencies that prevent a person from reporting all required information within the one-hour limit, the Executive Officer may extend the time for the reporting of required information provided such person has notified the Executive Officer of the breakdown within the one-hour limit.

(B) Within seven (7) calendar days after the breakdown has been corrected, but no later than thirty (30) calendar days from the initial date of the breakdown, unless an extension has been approved in writing by the Executive Officer, the Facility Permit holder shall submit a Breakdown Emissions Report to the Executive Officer which contains all of the following:

(i) an identification of the equipment involved in causing or suspected in having caused or having been affected by the breakdown;

(ii) the duration of the breakdown;

(iii) the date of correction and information demonstrating that compliance is achieved;

(iv) an identification of the types of emissions, if any, resulting from the breakdown;

(v) a quantification of the emissions in excess of those occurring under normal operating conditions (“excess emissions”), if any, resulting from the breakdown using a District-approved method consistent with the requirements of Rules 2011 and 2012 and Appendix A for each rule;

(vi) information substantiating that the breakdown did not result from operator error, neglect or improper operation or maintenance procedures;

(vii) information substantiating that steps were immediately taken to correct the condition causing the breakdown and to minimize the emissions, if any, resulting from the breakdown;

(viii) a description of the corrective measures undertaken and/or to be undertaken to avoid such a breakdown in the future; and

(ix) pictures of the equipment which failed, if available.

(2) Compliance During Breakdown

(A) Any rule or permit condition not specified in subparagraph (i)(2)(B) shall be inapplicable to a violation directly caused by a breakdown, provided that all of the following criteria are met:

(i) the Facility Permit holder meets the reporting requirements specified in paragraph (i)(1);

(ii) the breakdown did not result from operator error, neglect, or improper operation or maintenance procedures;

(iii) steps are immediately taken to correct conditions leading to the breakdown, and emissions caused by the breakdown are mitigated to the maximum extent feasible; and

(iv) the equipment in violation is shut down by the end of an operating cycle, or within twenty-four hours from the time the Facility Permit holder knew or reasonably should have known of the breakdown, whichever is sooner.

For the purpose of this rule, an operating cycle means a period of time within which a round of regularly recurring events is completed, and cannot be stopped without the risk of endangering public safety or health, causing material damage to the equipment or product, or cannot be stopped due to technical constraints. Economic reasons alone will not be sufficient to extend this time period. The operating cycle includes batch processes that may start and finish several times within a twenty-four hour period, in which case each start to finish interval is considered a complete cycle.

(B) Subparagraph (i)(2)(A) shall not apply to the following District Regulations, Rules and permit conditions:

(i) Regulations I, IX, X, XIV, XVII, XXX, and XXXI;

(ii) Rules 402, 2004 (b), (d), (e), (j), and (l), 2011, and 2012;

(iii) any permit condition which implements any Rule or Regulation specified in clause (i) or (ii).

(C) If a violation of any rule or permit condition not specified in subparagraph (i)(2)(B) is likely or suspected as a result of a reported breakdown, the Executive Officer will promptly investigate and determine whether the occurrence constitutes a breakdown in accordance with the criteria set forth in subparagraph (i)(2)(A). If the Executive Officer determines that the occurrence did not constitute a breakdown, no relief shall be granted under subparagraph (i)(2)(A).

(D) Equipment may be operated beyond the time limit in clause (i)(2)(A)(iv), provided that a petition for an emergency variance has been filed with the Clerk of the Hearing Board in accordance with Regulation V. In the event that the breakdown occurs or the time limit in clause (i)(2)(A)(iv) ends outside of the normal District working hours, the intent to file for an emergency variance shall be transmitted to the District in the manner and form prescribed by the Executive Officer.

(3) Excess Emissions and Annual Allocations

(A) The Facility Permit holder meeting the reporting requirements specified in paragraph (i)(1) may request that excess emissions not be counted in determining compliance with the RECLAIM facility's annual Allocation pursuant to the requirements specified in subparagraphs (i)(3)(B) or (i)(3)(C).

(B) Excess emissions occurring within the first 24 hours after the breakdown shall not be counted in determining compliance with the RECLAIM facility's annual Allocation if the Breakdown Emissions Report specified in subparagraph (i)(1)(B) contains the following additional information, and the Executive Officer approves the Breakdown Emissions Report:

(i) the names of operators of the identified equipment, their immediate supervisors, and the managers responsible for the operation and/or maintenance of the identified equipment; and

(ii) the names of any other witnesses to the breakdown, if any.

(C) Excess emissions occurring beyond the first 24 hours and up to thirty (30) calendar days after the breakdown shall not be counted in determining compliance with the RECLAIM facility's annual Allocation if the Breakdown Emissions Report specified in subparagraph (i)(1)(B) contains the additional information specified in subparagraph (i)(3)(B) and the following additional information, and the Executive Officer approves the Breakdown Emissions Report:

(i) information substantiating that it was beyond the RECLAIM Facility Permit holder's reasonable control to correct the breakdown condition within 24 hours; and

(ii) information substantiating that the RECLAIM Facility Permit holder was unable to provide on-site offsets for the excess emissions resulting from the breakdown.

(D) The Executive Officer will notify the RECLAIM Facility Permit holder, in writing, within thirty calendar days of submission of a Breakdown Emissions Report, regarding whether the report is approved or disapproved. If approved, the notification shall specify the duration during which the excess emissions resulting from the breakdown shall not be counted in determining the RECLAIM facility's annual Allocation, and the type and amount of emissions so exempt. If the Executive Officer does not respond within thirty days, the Facility Permit holder may deem the report denied for appeal purposes.

(j) Tampering

A person shall not tamper or interfere with, alter or adjust any monitoring or other equipment used to detect the amount, concentration, rate or other characteristic of emissions emanating from any source in a RECLAIM facility in any way which conceals or disguises the type and quantity of any such emissions.

(k) Compliance Dates

The failure to comply with any requirement in this regulation within the time specified shall constitute a separate violation for each day until such requirement is satisfied.

(l) Variances

No variance may be granted from the following provisions of this regulation:

(A) any provisions which require Permits to Construct or which set forth requirements for Permits to Construct;

(B) subdivision (n) of this rule or the missing data provisions of Appendices A to Rules 2011 and 2012; and

(C) subdivisions (b) and (d) of Rule 2004, and any permit conditions which state annual Allocations.

(m) Emergencies

In the event that responses to national, regional, or local emergencies require increased emissions in excess of Department of Defense (DoD) facility Allocations, such emissions shall not be counted for purposes of determining compliance with Rule 2004 (d)(1). The DoD facility will notify the Executive Officer, in writing, within one week after the start of increased emissions caused by emergency operations as listed above.

(n) Missing Data Provisions for Recordkeeping and Reporting

(1) In the event the Executive Officer determines that the emissions data developed or reported by the Facility Permit holder are inaccurate or incomplete or not derived in the manner required by this regulation or the Facility Permit, the missing data provisions set forth in Rules 2011 and 2012, Appendices A shall be used for the purpose of calculating emissions for recordkeeping, reporting, certification, and compliance with Allocations.

(2) In the event a facility does not meet the monitoring requirements, emissions shall be determined pursuant to the missing data provisions of the applicable Rule 2011 or 2012 Appendices A for purposes of determining compliance with Rule 2004 (d)(1).

(o) Emission Mitigation Fee Program for Power Producing Facilities

(1) The mitigation fee program specified in Rule 2020 may be used through the 2004 compliance year by power producing facilities that emit greater than their annual allocations provided the facility or any facility under common ownership has not transferred or sold RTCs to any other entity (other than facilities under common ownership) or the District since January 11, 2001 for any compliance year during which the mitigation fee program is used.

(2) The Executive Officer will:

(A) deduct RTCs in accordance with paragraphs (b)(3) and (b)(4) of Rule 2010; and

(B) replace the amount of deducted RTCs on a prorated basis according to the amount of RTCs generated, but not to exceed the original amount of RTCs deducted, no later than the compliance year during which RTCs are deducted.

(3) Notwithstanding the provisions of paragraphs (b)(3) and (b)(4) of Rule 2010, if the RTCs required to reconcile emissions pursuant to Rule 2004 (b)(1) is:

(A) less than the amount requested from the Mitigation Fee Program, then the difference between RTCs deducted from the future year allocation and RTCs required to reconcile emissions shall be refunded to the facility; or

(B) greater than the amount requested from the Mitigation Fee Program, then the facility shall be subject to the provisions of subdivision (d) of this rule, and paragraph (b)(1) and subdivisions (c) and (d) of Rule 2010, for the emissions in excess of the amount requested from the Mitigation Fee Program.

(p) RECLAIM Air Quality Investment Program (AQIP)

Emission reductions from the RECLAIM AQIP may be used through the 2004 compliance year by RECLAIM facilities that meet the definition of Structural Buyer, as defined in Rule 2000 (c)(74).

(q) Modeling Requirements

(1) If actual NOx or SOx emissions for any compliance year from a RECLAIM facility exceed its initial allocation provided by the District for that facility by forty (40) tons per year or more, the Facility Permit holder shall conduct modeling to analyze the potential impact of the increased emissions.

(2) The modeling analysis shall be submitted within 90 days of the end of the compliance year.

(3) Analysis shall be conducted for all equipment identified as a major source, as defined by Rule 2011 and Rule 2012 for the RECLAIM pollutants subject to the requirement in paragraph (q)(1), pursuant to the methodology in Rule 2005, Appendix A, consistent with applicable portions of 40 CFR Part 51, Appendix W, or other method approved by AQMD, CARB, and EPA.

3/17/17

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

(Adopted October 15, 1993)(Amended December 7, 1995)(Amended May 10, 1996)
(Amended July 12, 1996)(Amended February 14, 1997)(Amended April 9, 1999)
(Amended April 20, 2001)(Amended May 6, 2005)(Amended June 3, 2011)
(Amended December 4, 2015)

RULE 2005. NEW SOURCE REVIEW FOR RECLAIM

(a) Purpose

This rule sets forth pre-construction review requirements for new facilities subject to the requirements of the RECLAIM program, for modifications to RECLAIM facilities, and for facilities which increase their allocation to a level greater than their starting Allocation plus non-tradable credits. The purpose of this rule is to ensure that the operation of such facilities does not interfere with progress in attainment of the National Ambient Air Quality Standards, and that future economic growth in the South Coast Air Basin is not unnecessarily restricted.

(b) Requirements for New or Relocated RECLAIM Facilities

(1) The Executive Officer shall not approve the application for a Facility Permit to authorize construction or installation of a new or relocated facility unless the applicant demonstrates that:

(A) Best Available Control Technology will be applied to every emission source located at the facility; and

(B) the operation of any emission source located at the new or relocated facility will not cause a violation nor make significantly worse an existing violation of the state or national ambient air quality standard at any receptor location in the District for NO2 as specified in Appendix A. The applicant shall use the modeling procedures specified in Appendix A.

(2) The Executive Officer shall not approve the application for a Facility Permit authorizing operation of a new or relocated facility, unless the applicant demonstrates that:

(A) the facility holds sufficient RTCs, including any RTCs from Table 9 in Rule 2002, to offset the total facility emissions for the first year of operation, at a 1-to-1 ratio; and

(B) the RTCs procured to comply with the requirements of subparagraph (b)(2)(A) were obtained pursuant to the requirements of subdivision (e), and

(C) the total facility emissions determined to comply with the requirements of subparagraph (b)(2)(A) shall also include ship emissions directly associated with activities at stationary sources subject to this rule as follows:

(i) all emissions from ships during the loading and unloading of cargo and while at berth where the cargo is loaded or unloaded; and

(ii) non-propulsion ship emissions within coastal waters under District jurisdiction.

(c) Requirements for Existing RECLAIM Facilities, Modification to New RECLAIM Facilities, Facilities which Undergo a Change of Operator, or Facilities which Increase an Annual Allocation to a Level Greater Than the Facility's Starting Allocation Plus Non-tradable Credits.

(1) The Executive Officer shall not approve an application for a Facility Permit Amendment to authorize the installation of a new source or modification of an existing source which results in an emission increase as defined in subdivision (d), unless the applicant demonstrates that:

(A) Best Available Control Technology will be applied to the source; and

(B) the operation of the source will not result in a significant increase in the air quality concentration for NO2 as specified in Appendix A. The applicant shall use the modeling procedures specified in Appendix A.

(2) The Executive Officer shall not approve an application for a Facility Permit Amendment to authorize operation of the new or modified source which results in an emission increase as defined in subdivision (d), unless the applicant demonstrates that the facility holds sufficient RTCs to offset the annual emission increase for the first year of operation at a 1-to-1 ratio.

(3) The Executive Officer shall not approve an application for Change of Operator for a Facility Permit unless the applicant demonstrates that the facility holds sufficient RTCs for the compliance year in which the change of operator permit is issued. Credits must be held in an amount equal to:

(A) The annual Allocation initially issued to the original Facility Permit holder for existing facility as defined in Rule 2000 for the same compliance year, in which the change of operator permit is issued, multiplied, where applicable, by the Tradable/Usable RTC Adjustment Factor for the same compliance year as listed in Rule 2002(f)(1)(A); or

(B) The sum of annual RECLAIM pollutants from all the sources located at the facility. The amount of annual RECLAIM pollutants for each source shall be calculated by the maximum hourly potential to emit, over an operating schedule of 24 hours per day and 365 days per year, or shall be based on a permit condition limiting the source's emission.

(4) The Executive Officer shall not approve an application to increase an annual Allocation to a level greater than the facility's starting Allocation plus non-tradable credits, unless the applicant demonstrates that:

(A) each source which creates an emission increase as defined in subdivision (d) will:

(i) apply Best Available Control Technology;

(ii) not result in a significant increase in the air quality concentration for NO2 as specified in Appendix A; and

(B) the facility holds sufficient RTCs acquired pursuant to subdivision (e) to offset the annual increase in the facility's starting Allocation plus non-tradable credits at a 1-to-1 ratio for a minimum of one year.

(d) Emission Increase

An increase in emissions occurs if a source's maximum hourly potential to emit immediately prior to the proposed modification is less than the source's post-modification maximum hourly potential to emit. The amount of emission increase will be determined by comparing pre-modification and post-modification emissions on an annual basis by using: (1) an operating schedule of 24 hours per day, 365 days per year; or (2) a permit condition limiting mass emissions.

(e) Trading Zones Restrictions

Any increase in an annual Allocation to a level greater than the facility's starting plus non-tradable Allocations, and all emissions from a new or relocated facility must be fully offset by obtaining RTCs originated in one of the two trading zones as illustrated in the RECLAIM Trading Zones Map. A facility in Zone 1 may only obtain RTCs from Zone 1. A facility in Zone 2 may obtain RTCs from either Zone 1 or 2, or both.

(f) Offsets

The Facility Permit for a new or modified facility shall require compliance with this subdivision, if applicable.

(1) Any facility which was required to provide offsets pursuant to paragraphs (b)(2), or subparagraph (c)(4)(B) or any new facility required to provide offsets pursuant to paragraph (c)(2) shall, at the commencement of each compliance year, hold RTCs, including any RTCs from Table 9 in Rule 2002, in an amount equal to the amount of such required offsets. The Facility Permit holder may reduce the amount of offsets required pursuant to this subdivision by accepting a permit condition limiting emissions which shall serve in lieu of the starting Allocation plus non-tradable credits for purposes of paragraph (c)(4).

(2) Except for the RTCs referenced in Table 9 of Rule 2002, unused RTCs acquired to comply with this subdivision or with paragraphs (b)(2), (c)(2), or subparagraph (c)(4)(B) may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year.

(3) In lieu of compliance with paragraph (f)(2), the Facility Permit holder may accept a permit condition limiting quarterly emissions from the facility. A facility with quarterly emission limits may sell, at any time after the end of that quarter and prior to the end of the reconciliation period for that compliance year, unused RTCs acquired pursuant to this subdivision, excluding the RTCs referenced in Table 9 of Rule 2002, at the amount not to exceed the difference between the permitted emission limit for that quarter and the emissions during that quarter as reported to the District in the Quarterly Emission Certification. Any facility with quarterly certified emissions exceeding the quarterly emission limit for any quarter may sell RTCs, excluding the RTCs referenced in Table 9 of Rule 2002, only during the reconciliation period for the fourth quarter of the applicable compliance year. If there are a total of three exceedances in any five consecutive compliance years, the facility shall permanently comply with paragraph (f)(2) in lieu of (f)(3).

(g) Additional Federal Requirements for Major Stationary Sources

The Executive Officer shall not approve the application for a Facility Permit or an Amendment to a Facility Permit for a new, relocated or modified major stationary source, as defined in the Clean Air Act, 42 U.S.C. Section 7511a(e), unless the applicant:

(1) certifies that all other major stationary sources in the state which are controlled by the applicant are in compliance or on a schedule for compliance with all applicable federal emission limitations or standards (42 U.S.C. Section 7503(a)(3)); and

(2) submits an analysis of alternative sites, sizes, production processes and environmental control techniques for the proposed source which demonstrates that the benefits of the proposed source significantly outweigh the environmental and social cost imposed as a result of its location, construction, or modification (42 U.S.C. Section 7503(a)(5));

(3) Compliance Through California Environmental Quality Act.

The requirements of paragraph (g)(2) may be met through compliance with the California Environmental Quality Act in the following manner.

(A) if the proposed project is exempt from California Environmental Quality Act analysis pursuant to a statutory or categorical exemption pursuant to Title 14, California Code of Regulations, Sections 15260 to 15329, paragraph (g)(2) shall not apply to that project;

(B) if the proposed project qualifies for a negative declaration pursuant to Title 14 California Code of Regulations, Section 15070, or a mitigated negative declaration as defined in Public Resources Code Section 21064.5, paragraph (g)(2) shall not apply to that project; or

(C) if the proposed project has been analyzed by an environmental impact report pursuant to Public Resources Code Section 21002.1 and Title 14 California Code of Regulations, Section 15080 et seq., paragraph (g)(2) shall be deemed satisfied.

(4) Protection of Visibility

(A) Conduct a modeling analysis for plume visibility in accordance with the procedures specified in Appendix B if the net emission increase from the new or modified source exceeds 40 tons/year of NO_X; and the location of the source, relative to the closest boundary of a specified_Federal Class I area, is within the distance specified in Table 4-1.

Table 4-1

Federal Class I Area	*Distance (km)*
Agua Tibia	28
Cucamonga	28
Joshua Tree	29
San Gabriel	29
San Gorgonio	32
San Jacinto	28

(B) In relation to a permit application subject to the modeling analysis required by subparagraph (g)(4)(A), the Executive Officer shall:

(i) deem a permit application complete only when the applicant has complied with the requisite modeling analysis for plume visibility pursuant to subparagraph (g)(4)(A);

(ii) notify and provide a copy of the complete permit application file to the applicable Federal Land Manager(s) within 30 calendar days after the application has been deemed complete and at least 60 days prior to final action on the permit application;

(iii) consider written comments, relative to visibility impacts from the new or modified source, from the responsible Federal Land Manager(s), including any regional haze modeling performed by the Federal Land Manager(s), received within 30 days of the date of notification when determining the terms and conditions of the permit;

(iv) consider the Federal Land Manager(s) findings with respect to the geographic extent, intensity, duration, frequency and time of any identified visibility impairment of an affected Federal Class I area, including how these factors correlate with times of visitor use of the Federal Class I area, and the frequency and timing of natural conditions that reduce visibility; and,

(v) explain its decision or give notice as to where to obtain this explanation if the Executive Officer finds that the Federal Land Manager(s) analysis does not demonstrate that a new or modified source may have an adverse impact on visibility in an affected Federal Class I area.

(C) If a project has an adverse impact on visibility in an affected Federal Class I area, the Executive Officer may consider the cost of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, the useful life of the source, and all other relevant factors in determining whether to issue or deny the Permit to Construct or Permit to Operate.

(h) Public Notice

The applicant shall provide public notice, if required, pursuant to Rule 212 - Standards for Approving Permits.

(i) Rule 1401

All new or modified sources shall comply with the requirements of Rule 1401 - New Source Review of Carcinogenic Air Contaminants, if applicable.

(j) Compliance with State and Federal New Source Review Requirements

The Executive Officer will report to the District Governing Board regarding the effectiveness of Rule 2005 in meeting the state and federal New Source Review requirements for the preceding year. The Executive Officer may impose permit conditions to monitor and ensure compliance with such requirements. This report shall be incorporated in the Annual Program Audit Report prepared pursuant to Rule 2015(b)(1).

(k) Exemptions

(1) Functionally identical source replacements are exempt from the requirements of subparagraph (c)(1)(B) of this rule.

(2) Physical modifications that consist of the installation of equipment where the modification will not increase the emissions rate of any RECLAIM pollutant, and will not cause an increase in emissions above the facility's current year Allocation, shall be exempt from the requirements of paragraph (c)(2).

(3) Increases in hours of operation or throughput for equipment or processes permitted prior to October 15, 1993 that the applicant demonstrates would not violate any permit conditions in effect on October 15, 1993 which were imposed in order to limit emissions to implement New Source Review offset requirements, shall be exempt from the requirements of this rule.

(4) Increase to RECLAIM emission concentration limits or emission rates not associated with Best Available Control Technology permit conditions provided that the increase is not a result of any modification to equipment shall be exempt from the requirements of this rule.

(5) The requirements under subparagraphs (b)(1)(B) and (c)(1)(B), and clause (c)(4)(A)(ii) shall not apply to equipment used exclusively on a standby basis for non-utility electrical power generation or any other equipment used on a standby basis in case of emergency, provided the source does not operate more than 200 hours per year as evidenced by an engine-hour meter or equivalent method and is listed as emergency equipment in the Facility Permit.

APPENDIX A

The following sets forth the procedure for complying with the air quality modeling requirements. An applicant must either (1) provide an analysis approved by the Executive Officer or designee, or (2) show by using the Screening Analysis below, that a significant change (increase) in air quality concentration will not occur at any receptor location for which the state or national ambient air quality standard for NO_2 is exceeded.

Table A-1 of the screening analysis is subject to change by the Executive Officer, based on improved modeling data.

SCREENING ANALYSIS

Compare the emissions from the equipment you are applying for to those in Table A-1. If the emissions are less than the allowable emissions, no further analysis is required. If the emissions are greater than the allowable emissions, a more detailed air quality modeling analysis is required.

Table A-1
Allowable Emissions
for Noncombustion Sources and for
Combustion Sources less than 40 Million BTUs per hour

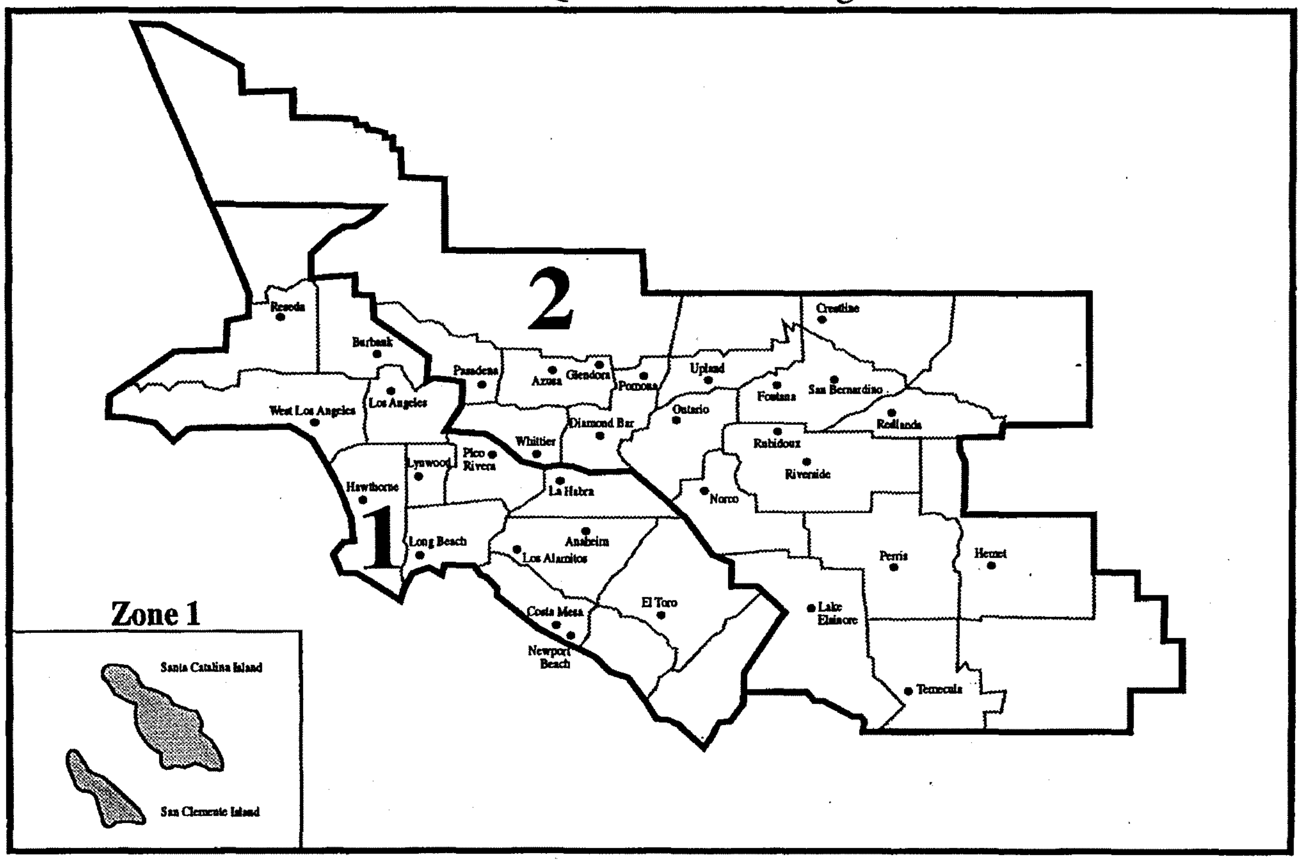
Heat Input Capacity (million BTUs/hr)	NOx (lbs/hr)
Noncombustion Source	0.068
2	0.20
5	0.31
10	0.47
20	0.86
30	1.26
40	1.31

Table A-2
Most Stringent Ambient Air Quality Standard and
Allowable Change in Concentration
For Each Air Contaminant/Averaging Time Combination

Air Contaminant	Averaging Time	Most Stringent Air Quality Standard		Significant Change in Air Quality Concentration	
Nitrogen Dioxide	1-hour	25 pphm	500 ug/m^3	1 pphm	20 ug/m^3
	Annual	5.3 pphm	100 ug/m^3	0.05 pphm	1 ug/m^3

RECLAIM Trading Zones

South Coast AQMD Air Monitoring Stations



APPENDIX B

MODELING ANALYSIS FOR VISIBILITY

(a) The modeling analysis performed by the applicant shall consider:

(1) the net emission increase from the new or modified source; and

(2) the location of the source and its distance to the closest boundary of specified Federal Class I area(s).

(b) Level 1 and 2 screening analysis for adverse plume impact pursuant to paragraph (g)(4) of this rule for modeling analysis of plume visibility shall consider the following applicable screening background visual ranges:

Federal Class I Area	Screening Background Visual Range (km)
Agua Tibia	171
Cucamonga	171
Joshua Tree	180
San Gabriel	175
San Gorgonio	192
San Jacinto	171

For level 1 and 2 screening analysis, no adverse plume impact on visibility results when the total color contrast value (Delta-E) is 2.0 or less and the plume contrast value (C) is 0.05 or less. If these values are exceeded, the Executive Officer shall require additional modeling. For level 3 analysis the appropriate background visual range, in consultation with the Executive Officer, shall be used. The Executive Officer may determine that there is no adverse visibility impact based on substantial evidence provided by the project applicant.

(c) When more detailed modeling is required to determine the project's visibility impact or when an air quality model specified in the Guidelines below is deemed inappropriate by the Executive Officer for a specific source-receptor application, the model may be modified or another model substituted with prior written approval by the Executive Officer, in consultation with the federal Environmental Protection Agency and the Federal Land Managers.

(d) The modeling analysis for plume visibility required pursuant to paragraph (g)(4) of this rule shall comply with the most recent version of:

(1) "Guideline on Air Quality Model (Revised)" (1986), supplement A (1987), supplement B (1993) and supplement C (1994), EPA-450/2-78-027R, US EPA, Office of Air Quality Planning and Standards Research Triangle Park, NC 27711; and

(2) "Workbook for Plume Visual Impact Screening and Analysis (Revised)," EPA-454-/R-92-023, US EPA, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711;

(3) "User's Manual for the Plume Visibility Model (PLUVUE II) (Revised)," EPA-454/B-92-008, US EPA, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711 (for Level-3 Visibility Analysis)

(Adopted October 15, 1993)(Amended December 7, 1995)(Amended May 11, 2001)

RULE 2006. PERMITS

(a) Purpose

The purpose of this rule is to set forth the procedures for issuing and amending Facility Permits.

(b) Issuance of Facility Permit

(1) The Executive Officer will compile a draft inventory of sources at each Cycle 1 RECLAIM facility and provide the draft inventory to the prospective Facility Permit holder of each such facility. No later than six months after providing the draft inventories to the Cycle 1 facilities, the Executive Officer will compile a draft inventory of sources at each Cycle 2 RECLAIM facility and provide the draft inventory to the prospective Facility Permit holder of each such facility.

(2) Within 30 days of receipt of the draft inventory, the prospective Facility Permit holder shall submit inventory corrections to the Executive Officer. At a minimum, the prospective Facility Permit holder shall identify each source of RECLAIM pollutants located at the facility, and shall submit equipment descriptions and operating parameters for such sources if required by the Executive Officer. Equipment previously exempt pursuant to Rule 219 - Equipment Not Requiring a Written Permit Pursuant to Regulation II, shall be listed by category. Inventory corrections shall be submitted in a form and manner specified by the Executive Officer.

(3) After receiving the corrected list of emission sources from the facility, the Executive Officer will, based on the corrected list and any other relevant information, issue a Facility Permit for each RECLAIM facility. The Facility Permit will be issued by January 1, 1994 for Cycle 1 facilities and by July 1, 1994 for Cycle 2 facilities.

(4) Each Facility Permit shall include the following terms and conditions:

(A) a description of each source or process unit and emission control device located at the facility, including sources of non-RECLAIM pollutants. Equipment previously exempt pursuant to Rule 219 - Equipment Not Requiring a Written Permit Pursuant to Regulation II, shall be listed by category and updated annually with the submittal of the APEP Report.

(B) a starting Allocation for the initial compliance year, which shall be calculated pursuant to Rule 2002 - Allocations for Oxides of Nitrogen (NO_x) and Oxides of Sulfur (SO_x);

(C) an Allocation for each compliance year through the year 2010, determined pursuant to Rule 2002 - Allocations for Oxides of Nitrogen (NO_x) and Oxides of Sulfur (SO_x);

(D) emission rates, or concentration limit, if applicable, and emission monitoring, recordkeeping and reporting conditions for each emission source in accordance with Rules 2011 - Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Sulfur (SO_x) Emissions, 2012 - Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Nitrogen (NO_x) Emissions;

(E) applicable federal Clean Air Act Title V requirements;

(F) conditions, other than concentration limits, appropriate to ensure that the source is operated within the applicable range of any emission rate specified for the source pursuant to Rules 2011 - Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Sulfur (SO_x) Emissions, and/or 2012 - Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Nitrogen (NO_x) Emissions;

(G) all permit conditions applicable to sources at the facility which were in effect immediately prior to issuance of the Facility Permit and which relate to toxics and other non-RECLAIM pollutants;

(H) conditions necessary to ensure continued compliance with BACT requirements imposed prior to issuance of the Facility Permit;

(I) all permit conditions applicable to sources at the facility immediately prior to issuance of the Facility Permit, provided that, unless the conditions are otherwise required by this regulation, such conditions will be in effect until December 31, 1994 for Cycle 1 facilities and June 30, 1995 for Cycle 2 facilities, or until such date the Executive Officer determined in writing that the facility has complied with all monitoring and reporting requirements of Rule 2011 or 2012, as applicable, whichever is later;

(J) permit conditions to ensure enforceability of, and compliance with, all applicable District rules and state and federal statutes and regulations which the District has jurisdiction to enforce;

(K) the term of the Facility Permit; and

(L) any other provisions necessary to assure compliance with District rules or state or federal statutes or regulations

(5) For facilities identified after January 1, 1994 as being subject to RECLAIM pursuant to Rule 2001 (c)(1)(D), the Executive Officer will issue a Facility Permit which will contain those provisions specified in paragraph (b)(4) of this rule.

(6) For facilities which enter RECLAIM pursuant to Rule 2001 (f), the Facility Permit will contain those provisions specified in paragraph (b)(4) of this rule.

(7) The Facility Permit shall serve as the Permit to Operate within the meaning of Rule 203 - Permit to Operate, for all equipment and sources at the facility. All valid preexisting Permits to Operate and Permits to Construct will be incorporated into the Facility Permit. An amendment to a Facility Permit may constitute both a Permit to Construct a modified source within the meaning of Rule 201 - Permit to Construct, and a Permit to Operate the modified source.

(8) Operation of any source that is not listed in the Facility Permit in the manner described in subparagraph (b)(4)(A) shall constitute a violation of this rule.

(9) The terms and conditions of the Facility Permit may be appealed to the Hearing Board. Such an appeal shall be filed within 30 days of the issuance of the permit or amendment thereto. The pendency of an appeal shall not stay the effect of the permit.

(c) Amendments to Facility Permits and the RTC Listing

(1) The Executive Officer will annually decrease an Allocation when the Facility Permit holder is a seller of RTCs and has complied with Rule 2007 - Trading Requirements.

(2) The Executive Officer will decrease a facility's Allocation pursuant to Rule 2010 (b)(1) when the Facility Permit holder has been found to be in violation of Rule 2004 (d).

(3) The Executive Officer will annually increase an Allocation when:

(A) the buyer of RTCs has an approved Facility Permit;

(B) the Facility Permit holder has complied with Rule 2007 - Trading Requirements, and with Rule 2005 - New Source Review for RECLAIM, if applicable; and

(C) the buyer of RTCs has not requested an RTC certificate.

(4) The Executive Officer shall deny any application for permit amendment unless the applicant demonstrates that operation of the facility, pursuant to the proposed revised permit will comply with all applicable District rules, and state and federal statutes and regulations which the District has jurisdiction to enforce.

(5) The Executive Officer may, upon annual renewal, add or amend written conditions on the Facility Permit to assure compliance with, and enforceability of, any applicable District rule, or state or federal statute or regulation which the District has jurisdiction to enforce.

(Adopted October 15, 1993)(Amended December 7, 1995)(Amended May 11, 2001)
(Amended December 5, 2003)(Amended September 3, 2004)(Amended January 7, 2005)
(Amended May 6, 2005)(Amended April 6, 2007)

RULE 2007. TRADING REQUIREMENTS

(a) Purpose

The purpose of this rule is to define the RECLAIM trading unit and to establish trading requirements for RECLAIM.

(b) Nature of RECLAIM Trading Credits (RTCs)

(1) An RTC is a limited authorization to emit RECLAIM pollutants in accordance with the restrictions and requirements of District rules and state and federal law.

(2) An RTC may be bought, sold, traded or otherwise transferred or acquired in accordance with the provisions of this rule.

(3) An RTC shall not constitute a security or other form of property, but may be used as collateral or security for indebtedness.

(4) The District reserves the right to amend the RECLAIM rules in response to program reevaluations pursuant to Rule 2015 - Backstop Provisions, or at other times. Nothing in District rules shall be construed to limit the District's authority to condition, limit, suspend or terminate any RTCs or the authorization to emit which is represented by a Facility Permit.

(c) Term of RTCs

(1) An RTC shall be denominated in terms of one pound of a RECLAIM pollutant and shall have a term of one year. Cycle 1 facilities, representing approximately half of the total RTCs allocated in each trading zone, will receive RTCs that have an issue date of January 1 and an expiration date of December 31. The remaining Cycle 2 facilities will receive RTCs that have an issue date of July 1 and an expiration date of June 30.

(2) A Facility Permit holder may acquire and use RTCs, except as provided in paragraphs (c)(4), (c)(5), and (c)(6), issued in either cycle regardless of the facility's initial RTC allocation cycle. However, the expiration date of an RTC is not affected by trading for use in the other cycle.

(3) A Facility Permit holder may acquire and use expired RTCs, except as provided in paragraph (c)(4), (c)(5), and (c)(6), to reconcile emissions during a quarter in which the annual Allocation was exceeded, if the following conditions are met:

(A) such transaction and use occurs during the reconciliation period immediately following the quarter during which the subject emissions occurred; and

(B) the RTCs are used to reconcile emissions that occurred during the RTC term.

(4) Not withstanding Rule 2004, a Facility Permit holder of a Power Producing Facility may not use NOx RTCs to reconcile emissions for any quarter starting on or after January 1, 2001 and ending January 7, 2005, unless such RTCs were:

(A) acquired prior to January 12, 2001 by the Facility Permit holder or any facility under common ownership, or

(B) generated under an approved emission reduction credit program, other than RECLAIM allocations, or

(C) acquired pursuant to paragraph (c)(8) of this rule.

The date of acquisition of RTCs specified in subparagraph (c)(4)(A) shall be evidenced by either the RTC Listing, as provided under subdivision (d) of this rule, or by a purchase agreement that was executed by both trading parties on or before January 11, 2001 for which the RTC trade registration was received by the Executive Officer by either May 1, 2001, or May 11, 2001 if the purchase agreement or contract was for future transfer of RTCs. The execution date of the purchase agreement shall be evidenced by either notarization or sworn statements by the trading parties.

(5) Notwithstanding paragraph (c)(4) of this rule, RTCs purchased after January 11, 2001, and the trade registration was received by the Executive Officer prior to May 1, 2001, may be used for demonstrating compliance with the first quarter of calendar year 2001 only.

(6) The Facility Permit holder of a Power Producing Facility may sell NOx RTCs to the District at a price not to exceed the Participation Fee specified in Rule 2020 (h)(1). Such sales shall not disqualify the facility from participating in the Mitigation Fee Program.

(7) A Facility Permit holder of a Power Producing Facility may sell NOx RTCs above the facility's original allocation issued by the District for each compliance year. Transfer of such RTCs to any party prior to January 7, 2005 shall disqualify the Facility Permit Holder from participating in the Mitigation Fee Program for the year or years for which the RTCs are transferred or sold.

(8) Notwithstanding the requirements of paragraph (c)(7), on and after January 7, 2005, a Facility Permit holder of a Power Producing Facility may buy NOx RTCs valid for Compliance Year 2005 or any future compliance year from any party.

(9) Notwithstanding the requirements of paragraph (c)(7), on and after January 7, 2005, a Facility Permit holder of a Power Producing Facility may only sell or transfer NOx RTCs of its original allocation issued by the District for Compliance Years 2005 or 2006 to new power generating facilities brought on line as of January 1, 2004 or later, and may sell or transfer NOx RTCs for Compliance Year 2007 or any future compliance year of its original allocation issued by the District to any party.

(10) Notwithstanding the requirements of paragraph (c)(7), on and after January 7, 2005, a Facility Permit holder of a Power Producing Facility may sell or transfer NOx RTCs to another facility under common ownership for any compliance year.

(d) RTC Listing

The Executive Officer will maintain an RTC Listing specifying all RTCs held by each facility or person. The listing is the official and controlling record of RTC holdings. The Executive Officer will amend the RTC Listing upon any of the following actions:

(1) RTC transfer;

(2) change in name of an RTC holder;

(3) expiration of unused RTCs;

(4) a reduction of a facility's annual emission Allocation pursuant to Rule 2010 (b)(1)(A) or (b)(3); or

(5) at the end of each quarter's reconciliation period.

(e) Acquisition of RTCs

RTCs may be acquired only as follows:

(1) Initially, the Facility Permit holder is granted, pursuant to Rule 2002, RTCs for each year equal to the facility's annual Allocation for that year.

(2) Any person may acquire RTCs through purchase, trade or other means of transfer from any person who holds RTCs. The following requirements shall govern the transfer of RTCs:

(A) The transfer of RTCs shall be effective only upon amendment by the Executive Officer of the RTC Listing.

(B) The Executive Officer shall not amend the RTC Listing unless the seller and the buyer have jointly filed a Registration of RTC Transfer. The Registration of RTC Transfer shall include, but not be limited to, the following information:

(i) identification of the seller and buyer. If the seller is an agent, broker, or other intermediary representing the owner of the RTC, the owner of the RTC shall also be identified. In the case of pooled transactions or markets, buyers and owners of RTCs involved in the transactions of RTCs can be identified in aggregate;

(ii) RTC expiration date;

(iii) purchase agreement or transaction confirmation;

(iv) the amount and type of emissions involved in this transaction for each buyer, seller, and owners of RTCs;

(v) the transaction date;

(vi) the RECLAIM trading zone from which the RTCs originated;

(vii) the price per pound of emissions, if sold;

(viii) if the RTCs for transfer are for the current compliance year, the seller shall indicate one or more of the following four causes for the generation of RTCs:

(I) process change;

(II) addition of control equipment;

(III) production decrease; or

(IV) equipment or facility shutdown.

If the seller is not a RECLAIM facility, and cause for generation has been previously reported, no cause need be indicated.

(ix) if the RTCs for transfer are valid for a subsequent compliance year, the seller shall comply with clause (viii) or may alternatively indicate that the manner of generating the RTCs has not yet been determined;

(x) the buyer shall indicate one or more of the following three uses of the RTCs:

(I) issuance of RTC Certificate;

(II) increase of Allocation to satisfy annual compliance or increased production; or

(III) use under Rule 2005 - New Source Review for RECLAIM.

(xi) the origin of the RTCs, such as allocation issued by the District, converted from mobile source emission reduction credits, or converted from area source credits.

(C) The parties to an agreement for a contingent right to purchase RTCs shall report to the District the total volume of RTCs in such contract agreement, the dates, the relevant time frames for the future delivery of credits, and all prices paid within five (5) business days of the contract agreement. An agent, broker, or other intermediary representing the contracting parties may report on their behalf. Such a report need not identify the potential buyer and seller. Once the contingent right has been exercised, a Registration of RTC Transfer shall be submitted within five (5) business days and all other applicable rules shall apply.

(D) The Executive Officer shall not amend the RTC Listing to identify a new holder of RTCs, or to add RTCs to an existing RTC holder, until an equivalent amount of RTCs are debited from the seller.

(E) When RTCs are transferred from an Allocation, the debit shall result in an automatic amendment of the Allocation.

(F) When the buyer is a RECLAIM facility, the Executive Officer shall amend the buyer's Allocation or issue an RTC certificate in the name of the buyer, as requested pursuant to subparagraph (e)(2)(H).

(G) When the buyer is not a RECLAIM facility the Executive Officer will issue an RTC certificate in the name of the buyer.

(H) The seller and buyer shall jointly file a Registration of RTC Transfer within five (5) business days of the date of the trading transaction.

(I) The parties to an agreement for a forward contract shall report to the District all information regarding the transactions identified in subparagraphs (e)(2)(B)(i) through (vii), as well as the relevant time frames for the future delivery of credits, within five (5) business days of the contract agreement. An agent, broker, or other intermediary representing the contracting parties may report on their behalf. If the buyer or seller requests confidentiality, the District will keep the identities of the buyer and of the seller confidential to the extent allowed by law until the contract has been exercised as a transfer of RTCs. Once the forward contract has been exercised, a Registration of RTC Transfer shall be submitted within five (5) business days and all other applicable rules shall apply.

(J) A buyer or seller who is not a RECLAIM Facility Permit holder and who is not domiciled in the State of California shall submit contemporaneously with the filing of the Registration of RTC Transfer, or have on file with the District:

(i) written proof of appointment of a licensed Agent for Service of Process within the State of California with such appointment being effective for at least an additional four years after the most recent trade, in a manner and form specified by the Executive Officer;

(ii) written consent that, in the event of any dispute regarding any purchase or sale of RTCs, the transaction and the resolution of any related dispute, claim or prosecution shall be governed by the laws of the State of California, and;

(iii) written consent that the Superior Court of the State of California, County of Los Angeles, shall have jurisdiction and shall be the proper venue for any legal proceeding relating to any sale or purchase of RTCs.

(3) For pooled transactions or markets, in the event that any of the RTCs involved in the transactions are subsequently invalidated, the agent, broker, or intermediary representing the buyers and sellers shall revise the transaction or identify the specific buyers and sellers of each RTC transferred within 2 business days of written notice by the Executive Officer. Failure to provide the information shall constitute a violation of this rule and result in invalidation of all pooled buyer's RTCs in proportion to the amount obtained in the purchase. If this does not occur, each buyer of the RTCs involved in the pooled transaction or market shall be subject to a violation notice.

(f) Date of Eligibility for Trading of RTCs

(1) RTCs issued as part of an Allocation are eligible for transfer upon approval of the Facility Permit;

(2) RTCs credited pursuant to Rule 2008 - Mobile Source Credits, are eligible for transfer upon issuance; and

(3) RTCs to replace existing ERCs held by non-RECLAIM facilities pursuant to Rule 2002 (c)(5) are eligible for transfer upon issuance.

(g) RTC Certificates

(1) RTC Certificates may only be issued by the Executive Officer for RTCs which are not part of an Allocation.

(2) RTC Certificates shall designate the name of the holder, the Regulation XIII zone and RECLAIM trading zone from which the RTC originated, the issue date, the expiration date, and an annual emissions value.

(3) RTC Certificates may be acquired by transfer as set forth in subdivision (e). In addition, a Facility Permit holder may elect to reduce the Allocation and, upon such amendment to the Facility Permit by the Executive Officer, shall be issued an RTC Certificate. The value of the certificate shall be equivalent to the reduction in the Allocation in the year for which the certificate is issued.

(4) RTC certificates may be surrendered for application to create or increase an Allocation.

(h) Retirement of RTCs

RTCs may be surrendered to the District for retirement from the market. All RTC retirements will be documented annually through the annual program audit, and used to provide further progress for clean air. RTCs retired to their issue date shall be exempt from the RTC Allocation Fee specified in Rule 301 - Permit Fees.

(i) RTC Trading Prohibition

No person shall, in connection with any agreement or proposed agreement for the transfer of any RTC, knowingly make or cause to be made to any other person any false report or statement regarding RTCs.

3/21/94

(Adopted October 15, 1993)

RULE 2008. MOBILE SOURCE CREDITS

(a) Purpose

The purpose of this rule is to establish criteria for and requirements on utilizing emission reductions generated from 1600 series rules as RTCs.

(b) Requirements

(1) RTCs may be issued based on emission reductions which comply with all requirements of any 1600 series rule, except that any person may generate and receive such RTCs. RTCs may only be generated from vehicles registered in the Basin.

(2) In order to receive RTCs pursuant to Rule 1610 as specified in this rule, a minimum of 100 vehicles shall be scrapped, subsequent to the adoption of this rule.

(3) The first annual issue date of RTCs shall be the scheduled RTC issue date immediately following the date on which the reductions were deemed eligible for use pursuant to Regulation XVI - Mobile Source Offset Programs, or the current compliance year, if requested. Zone 1 shall be the zone of origination for all RTCs obtained pursuant to this rule.

(c) Limitations

The Executive Officer will approve plans for scrapping vehicles pursuant to Regulation XVI, for no more than 30,000 vehicles per year.

(Adopted October 15, 1993)(Amended May 11, 2001)(Amended January 7, 2005)
(Amended April 6, 2007)

RULE 2010. ADMINISTRATIVE REMEDIES AND SANCTIONS

(a) Purpose

This rule specifies provisions to ensure that RECLAIM facilities which exceed their Allocation provide compensating emission reductions. This rule also provides for administrative penalties for RECLAIM rule violations.

(b) Emissions in Excess of Allocation

(1) Upon determining that a Facility Permit holder has violated Rule 2004 (d), the Executive Officer will:

(A) reduce the facility's annual emissions Allocation for the compliance year following the determination by the total amount the Allocation was exceeded. The total amount exceeded is calculated as the sum of the individual quarterly exceedances. If the original facility has undergone a complete or partial change of operator during or subsequent to the compliance year in which the violation occurred, any later Facility Permit holder who has a valid Facility Permit resulting from that or any subsequent change of operator shall be held both individually and jointly liable with the original Facility Permit holder that violated Rule 2004 (d) for the total Allocation exceedances. The Executive Officer will reduce the Allocation or account of the facility operator who caused the violation to cover the amount of exceedances to the maximum extent possible. The Executive Officer will proportion any remaining required reductions among any later facility operators holding valid Facility Permits based on each facility's potential to emit the pollutant of the exceedance. Additionally, the Executive Officer may revise the Facility Permits of the original and subsequent Facility Permit holders in accordance with subparagraph (b)(1)(B)

(B) revise the Facility Permit to impose any conditions the Executive Officer determines to be appropriate to prevent future violations of Rule 2004 (d).

(2) If the Executive Officer petitions for a permit revocation pursuant to Health and Safety Code Section 42307 due to a violation of Rule 2004 (d), and the Hearing Board finds that Rule 2004 (d) was violated, it may revoke the Facility Permit pursuant to Health and Safety Code Section 42309 and invalidate all RTCs held for the facility's use. Any subsequent application for a Facility Permit filed for that facility shall be subject to all requirements of Rule 2005 - New Source Review for RECLAIM.

(3) Upon approval of a request for emission reductions from the Mitigation Fee Program, the Executive Officer will deduct RTCs equal to the amount of emissions in the approved request from the facility's RTC holding in the second compliance year or earlier following the compliance year in which emissions are requested. Deductions for compliance years 2001, 2002, and 2003 can be extended by no more than one additional year provided the Mitigation Fee Program achieves at least 75 percent reductions, in aggregate, by the second compliance year. However, emissions requested from the Mitigation Fee Program for compliance year 2004 shall be deducted no later than the 2005 compliance year.

(4) Upon Executive Officer approval of a request from a Facility Permit holder subject to the deductions under paragraph (b)(3) of this rule, a facility may set aside from such deductions the amount no greater than the amount of RTCs necessary to meet the requirements of Rule 2005 (c) to operate new electric generating equipment permitted and constructed after May 11, 2001. If actual NOx emissions from such new equipment is less than the amount of RTCs set aside, the remaining balance of the set aside RTCs shall be subject to the requirements of paragraph (b)(3). Such set aside shall not exempt a Facility Permit holder from accounting for all RECLAIM NOx emissions at its facility.

(c) Administrative Penalties

(1) For any violation of RECLAIM, the Executive Officer may seek an administrative penalty up to $500 per violation, per day, pursuant to Health and Safety Code Section 42402.5. If administrative penalties are sought, the Executive Officer will:

(A) provide written notice of the administrative penalty to the Facility Permit holder, including a written explanation of the basis for the penalty;

(B) provide an opportunity for a hearing by the Executive Officer or designee(s) within thirty (30) days of the date of the notice. The hearing shall include the right to call and examine witnesses under oath, the right to introduce exhibits, and the right to a record of the hearing.

(C) The hearing shall not be conducted according to technical rules of evidence. The rules of privilege shall be effective to the same extent that they are recognized in civil actions, and irrelevant evidence shall be excluded.

(D) Within thirty (30) days after the hearing, the Executive Officer or designee(s) will mail to the Facility Permit holder a notice of final decision including a statement of reasons therefore.

(E) In determining the amount of administrative penalty to be assessed, the Executive Officer or designee(s) will take into account all relevant circumstances, including but not limited to, the factors specified in Health and Safety Code Section 42403.

(2) The Facility Permit holder shall pay any administrative penalty within thirty (30) days after receipt of notice pursuant to subparagraph (c)(1)(A), or if a hearing has been held, within thirty (30) days of the date of receipt of notice pursuant to subparagraph (c)(1)(D). If the penalty is not paid when due, the Executive Officer may petition the Hearing Board to revoke the Facility Permit. If the Hearing Board finds that the penalties have not been paid, it shall revoke the Facility Permit.

(d) Other Remedies and Sanctions

The remedies and sanctions provided in this rule are in addition to any sanctions, penalties, actions or other remedies available under law.

(Adopted October 15, 1993) (Amended March 10, 1995)(Amended September 8, 1995)
(Amended December 7, 1995)(Amended July 12, 1996)(Amended February 14, 1997)
(Amended April 11, 1997)(Amended April 9, 1999)(Amended March 16, 2001)
(Amended May 11, 2001)(Amended December 5, 2003)(Amended January 7, 2005)

RULE 2011. REQUIREMENTS FOR MONITORING, REPORTING, AND RECORDKEEPING FOR OXIDES OF SULFUR (SO_X) EMISSIONS

(a) Purpose

The purpose of this rule is to establish the monitoring, reporting, and recordkeeping requirements for SO_X emissions under the RECLAIM program.

(b) Applicability

The provisions of this rule shall apply to any RECLAIM SO_X source or SO_X process unit. The SO_X sources and process units regulated by this rule include, but are not limited to:

Boilers	Fluid Catalytic Cracking Units
Internal Combustion Engines	Dryers
Heaters	Fume Incinerators/Afterburners
Gas Turbines	Test Cells
Furnaces	Tail Gas Units
Kilns and Calciners	Sulfuric Acid Production
Ovens	Waste Incinerators

(c) Major SO_X Source

(1) Major SO_X source means any of the following SO_X sources, except for such SO_X sources reclassified to process units at approved Super Compliant Facilities as specified in paragraph (c)(4):

(A) any petroleum refinery fluid catalytic cracking unit;

(B) any tail gas unit;

(C) any sulfuric acid production unit;

(D) any equipment that burns refinery, landfill or sewage digester gaseous fuel, except gas flares;

(E) any existing equipment using SO_X CEMS or equivalent monitoring device, or that is required to install such monitoring device under District rules to be implemented as of October 15, 1993;

(F) any SO_X source or process unit elected by the Facility Permit holder or required by the Executive Officer or designee to be monitored with a CEMS or equivalent monitoring device;

(G) any SO_X source or process unit for which SO_X emissions reported pursuant to Rule 301 - Permit Fees, were equal to or greater than 10 tons per year for any calendar year between 1987 to 1991, inclusive, excluding any SO_X source or process unit which has reduced SO_X emissions to below 10 tons per year prior to January 1, 1994.

(2) The Facility Permit holder of a major SO_X source shall:

(A) install, maintain, and operate a direct monitoring device for each major SO_X source to continuously measure the concentration of SO_X emissions or fuel sulfur content and all other applicable variables specified in Table 2011-1 and Appendix A, Chapter 2, Table 2-A; or

(B) install, maintain, and operate an alternative monitoring device which has been determined by the Executive Officer or designee to be equivalent to CEMS in relative accuracy, reliability, reproducibility and timeliness according to the requirements set forth in Appendix A, Chapter 2.

(C) The operating requirements specified in subparagraph (c)(2)(A) or (c)(2)(B) shall not apply during any time period not to exceed 96 hours provided that all of the following are met:

(i) the Facility Permit holder reports emissions as specified in Appendix A;

(ii) the direct monitoring device has been either:

(I) shut down for maintenance performed pursuant to the facility's Quality Assurance and Quality Control Program or

(II) damaged in a fire or mechanical or electrical failure caused by circumstances beyond the Facility Permit holder's control; and

(iii) Whenever the monitoring device is non-operational for more than 24 hours, the Facility Permit holder shall submit a report to the Executive Officer within 96 hours after the device becomes non-operational. Such report shall include information as prescribed by the Executive Officer including at a minimum the cause of the shutdown, the time the monitoring device became non-operational, the time or estimated time the monitoring device returned to normal operation, and the maintenance performed or corrective and preventative actions taken to prevent future non-operational conditions.

If the source for which the CEMS is certified to monitor is not operating when the CEMS is in maintenance or being repaired, and either the flow or concentration monitor is properly operating, and clauses (c)(2)(C)(i) and (c)(2)(C)(ii) are met, then the above time period shall be extended for an additional 96 hours.

(3) The Facility Permit holder of a major SO_X source shall:

(A) install, maintain, and operate a reporting device to electronically report to the District Central SO_X Station for each major SO_X source: total daily mass emissions of SO_X and daily status codes. Such data shall be transmitted by 5:00 p.m. of the following day. If the facility experiences a power, computer, or other system failure that prevents the reporting of total daily mass emissions of SO_X and daily status codes, the Facility Permit holder shall be granted 24 hours to submit the required report. Between July 1, 1995 and December 31, 1995, SO_X emissions after the 24-hour extension, shall be calculated using interim reporting procedures set forth in Appendix A, Chapter 2. Starting January 1, 1996 and thereafter, SO_X emissions after the 24-hour extension shall be calculated pursuant to the missing data requirements set forth in Appendix A, Chapter 2. For each major SO_X source opting to comply with subparagraph (c)(10), reports of SO_X mass emissions shall be electronically filed on a monthly instead of daily basis; and

(B) submit Monthly Emissions Report aggregating SO_X emissions from all major sources within 15 days following the end of each calendar month. In its Monthly Emissions Report, the Facility Permit holder may correct daily transmitted data for that month, provided such corrections are clearly identified and justified.

(C) Notwithstanding subparagraph (c)(3)(A), starting May 11, 2001 if a power, computer, or other system failure precludes the Facility Permit holder from reporting total daily mass emissions of SO_X and daily status codes by 5:00 p.m., the Facility Permit holder shall be granted 96 hours to submit the required report provided that the raw data as obtained by the direct monitoring device is stored at the facility. SO_X emissions reported after the 96-hour extension shall be calculated pursuant to the missing data requirements set forth in Appendix A, Chapter 2. The provisions of this subparagraph shall be limited to no more than three non-consecutive occurrences per compliance year.

(D) The requirement of calculating emissions using Missing Data Procedures under subparagraph (c)(3)(A) shall not apply if the failure to report the total daily mass emissions of SO_X and daily status codes is due to a demonstrated failure at the District's Central Station preventing it from receiving the data. The Facility Permit holder shall submit the report within 48 hours of the problem being corrected, provided that the raw data as obtained by the direct monitoring device is stored at the facility. SO_X emissions reported after the 48-hour extension shall be calculated pursuant to the missing data requirements set forth in Appendix A, Chapter 2.

(4) Super Compliant Facilities

(A) Facilities operating at or below their adjusted 2003 Allocation as of their 1994 compliance year.

(i) The Facility Permit holder of major SO_X sources may reclassify its major SO_X sources to SO_X process units provided that (1) the facility's annual SO_X emissions as properly reported in its 1994 compliance year APEP report are already at or below the level of its adjusted compliance year 2003 SO_X Allocation. The adjusted compliance year 2003 SO_X Allocation shall be the compliance year 2003 SO_X Allocation as calculated pursuant to Rule 2002 subdivision (e) plus any compliance year 2003 SO_X RTCs resulting from conversion of ERCs which the Facility Permit holder had applied to own by July 1, 1994 and has continuously owned, unless such RTCs have already been accounted for in the compliance year 2003 Allocation as established pursuant to Rule 2002 subdivision (e); and (2) it submits a complete application for SO_X Super Compliance status on or before December 2, 1996. The Executive Officer will provisionally approve for purposes of paragraph (c)(5) such application if the Facility Permit holder has retired all SO_X RTCs in excess of the facility's adjusted compliance year 2003 Allocation for each of the compliance years from the year of application submittal through the 2010 compliance year. The Facility Permit holder need not retire any RTCs (excluding converted ERCs) which are held by transfer pursuant to Rule 2007 paragraph (e)(2); however, such non-retired RTCs must be converted into RTC certificates pursuant to Rule 2007 subdivision (g), transferred to a different holder, or retired. For the purposes of this rule, converted ERCs shall mean SO_X RTCs resulting from conversion of ERCs which the Facility Permit holder had applied to own by July 1, 1994 and has continuously owned.

(ii) Final approval of SO_X Super Compliant status shall be granted if the Executive Officer or designee approves the initial source test required by subparagraph (c)(4)(C) and the facility's total annual SO_X emissions has not exceeded its adjusted compliance year 2003 Allocation.

(B) Facilities not operating at or below their adjusted 2003 Allocation as of their 1994 compliance year.

(i) On or before December 2, 1996 the facility Permit holder of major SO_X sources may submit a complete application for SO_X Super Compliant status. Such applications must also include a complete application for permit modifications to install SO_X emission reduction equipment or to make any other physical modifications to substantially reduce emissions from each major SO_X source to be reclassified as a SOx process unit. The Executive Officer shall deny the application for Super Compliant status unless the applicant demonstrates the proposed modifications would comply with all applicable District rules and would permanently reduce the facility's total annual SO_X emissions to a level not to exceed its adjusted compliance year 2003 SO_X Allocation as defined in clause (c)(4)(A)(i), would not result in any increases in the mass emissions of any other air contaminant or in emissions to any other media, and would not result in any increases in receptor concentrations of any air contaminant in excess of the values identified in Table A-2 of Rule 1303;

(ii) Upon issuance of the permit to construct for the modification specified in clause (c)(4)(B)(i), the Executive Officer shall also issue a provisional approval of the facility's application for SO_X Super Compliant status for purposes of paragraph (c)(5).

(iii) Final approval of SO_X Super Compliant status shall be granted if the following provisions are met:

(I) An approved permit to operate has been issued for the modification specified in clause (c)(4)(B)(i);

(II) The facility's total annual SO_X emissions as reported in its APEP report are at a level at or below the facility's adjusted compliance year 2003 SO_X Allocation on a permanent basis no later than the facility's 1998 compliance year;

(III) The Facility Permit holder has retired all SO_X RTCs in excess of the facility's adjusted compliance year 2003 Allocation for each of the compliance years from the earlier of the facility's 1998 compliance year or the facility's first full compliance year with SO_X Super Compliant Facility status through the facility's 2010 compliance year. The Facility Permit holder need not retire any RTCs (excluding converted ERCs as defined in clause (c)(4)(A)(i) which are held by transfer pursuant to Rule 2007 paragraph (e)(2); however, such non-retired RTCs must be converted into RTC certificates pursuant to Rule 2007 subdivision (g), transferred to a different holder, or retired; and

(IV) The facility Permit holder has an approved initial source test as required under subparagraph (c)(4)(C).

(C) The Facility Permit holder shall have initial source tests conducted to establish an equipment specific emission rate, for each major source to be reclassified as a SO_X process unit, pursuant to Appendix A, Chapter 4, Subdivision D prior to January 1, 1998 for Cycle 1 facilities and prior to July 1, 1998 for Cycle 2 facilities. In lieu of an equipment specific emission rate, the Executive Officer may approve an equipment specific concentration limit if the Facility Permit holder demonstrates to the satisfaction of the Executive Officer that there are no measurable operating parameters to establish an accurate equipment specific emission rate. The Facility Permit holder shall have initial source tests conducted in accordance with test methods listed under Rule 2011, Appendix A, Chapter 4, Subdivision A - Test Methods, to establish emission levels of the source. The Facility Permit holder shall select an equipment-specific concentration limit for each major source which will be reclassified as a SO_X process unit. The concentration limits selected shall be consistent with the source test results and at a level adequate to allow continuous compliance and shall be enforceable through permit conditions.

(i) For facilities seeking Super Compliant status pursuant to subparagraph (c)(4)(A), the Facility Permit holder may use the concentration limit to determine emissions retroactive to the date of provisional approval of the application for SO_X Super Compliant status.

(ii) For facilities seeking Super Compliant status pursuant to subparagraph (c)(4)(B), the Facility Permit holder may use the concentration limit to determine emissions retroactive to the date of completion of modification.

(D) Requirements to maintain Super Compliant status.

Super Compliant status is contingent upon the Facility Permit holder meeting at all times the following provisions:

(i) Every major SO_X source at a Super Compliant SO_X facility which is reclassified as a SO_X process unit with an approved equipment specific emission rate shall be source tested a minimum of once every twelve months in order to establish an equipment specific emission rate, pursuant to Appendix A, Chapter 4, Subdivision D. These source tests shall be conducted every four calendar quarters after the initial source test. If a source test is not conducted within three months after the required date, the facility shall no longer be considered Super Compliant, unless upon good cause the Executive Officer has granted a written extension of time. The source test results shall, upon approval, constitute the basis for assigning equipment specific emission rates which shall be used for purposes of reporting emissions and determining compliance.

(ii) Every major SO_X source at a Super Compliant SO_X facility which is reclassified as a SO_X process unit with an approved equipment specific concentration limit shall comply with that limit on a sixty-minute basis. In addition, compliance with the approved equipment specific concentration limit shall be demonstrated by source test a minimum of once every six months. Such tests shall be conducted for a duration of sixty minutes in accordance to test methods listed under Rule 2011, Appendix A, Chapter 4, Subdivision A - Test Methods. These source tests shall be conducted every two calendar quarters after the initial source test. If a source test is not conducted within three months after the required date, the facility shall no longer be considered Super Compliant, unless upon good cause the Executive Officer has granted a written extension of time. If the results of a source test indicate non-compliance with the concentration limit then the Facility Permit holder shall select a new concentration limit which is consistent with the source test results unless the Facility Permit holder demonstrates to the satisfaction of the Executive Officer or designee that no change is warranted. If all tests conducted pursuant to this paragraph over a two-year period comply with the equipment-specific concentration limit then the facility shall have the option of reducing the source test frequency to once every four quarters. If any test conducted on a four quarter cycle exceeds the concentration limit then the facility shall return to conducting source tests every two quarters until the facility is able to demonstrate consecutive compliance over another two year period.

(iii) The facility's total annual SO_X emissions, as reported in its APEP report, shall not exceed the facility's adjusted compliance year 2003 SO_X Allocation. If there are such exceedances for two consecutive years or in any three years, the facility shall no longer be considered Super Compliant.

(5) Any Facility Permit holder of a facility which is provisionally approved for SO_X Super Compliant status shall have the option for each major SOx source to be reclassified as a SOx process unit, in lieu of following the procedures specified in clauses E(1)(d)(i), E(1)(d)(ii), and E(1)(d)(iii) of Appendix A Chapter 2, to monitor and report emissions pursuant to paragraph (d)(2). This option shall be available to the Facility Permit holder retroactively from July 1, 1995 if the complete application for SO_X Super Compliant status is submitted on or before January 2, 1996, or retroactively from the date of application submittal if the complete

application is submitted after January 2 and before December 3, 1996. If the facility is unsuccessful at obtaining final approval as a SO_X Super Compliant Facility then the procedures specified in clauses E(1)(d)(i), E(1)(d)(ii), and E(1)(d)(iii) of Appendix A Chapter 2 shall apply retroactively to each major SOx source reclassified as a process unit for which SO_X emissions had been calculated pursuant to paragraph (d)(2) from the date the facility began monitoring and reporting major SO_X source emissions as SO_X process unit emissions to the date a CEMS is installed and certified.

(6) After final approval of Super Compliant status, a Facility Permit holder may elect to discontinue its Super Compliant status and increase its annual Allocations above the level of its adjusted compliance year 2003 Allocation provided it first meets all of the following requirements:

(A) The Facility Permit holder submits an application to discontinue SO_X Super Compliant status and to have all sources at the facility that were reclassified from major SO_X sources to SO_X process units pursuant to paragraph (c)(4) permanently revert back to major SO_X sources;

(B) The Facility Permit holder installs, operates, and certifies in compliance with Rule 2012 paragraphs (c)(2) and (c)(3) monitoring and reporting systems on each source at the facility that was reclassified from a major SO_X source to a SO_X process unit pursuant to paragraph (c)(4); and

(C) The Facility Permit holder acquires, pursuant to Rule 2007, sufficient RTCs to ensure that the facility continuously operates in compliance with Rule 2004 subdivision (d).

(7) If a facility designated as a SO_X Super Compliant Facility pursuant to paragraph (c)(4) exceeds its adjusted compliance year 2003 SO_X Allocation, then the facility shall acquire, pursuant to Rule 2007, sufficient RTCs to cover such exceedance and shall be considered in violation of Rule 2004(d)(1).

(8) If the Executive Officer determines that a facility designated as a SO_X Super Compliant Facility exceeds its adjusted compliance year 2003 SO_X Allocation for two consecutive years or any three years, then that facility shall no longer be considered Super Compliant. If a facility loses its Super Compliant status pursuant to this paragraph or subparagraph

(c)(4)(D), all sources at the facility that were reclassified from major SO_X sources to SO_X process units pursuant to paragraph (c)(4) shall permanently revert back to major SO_X sources and shall become subject to the monitoring and reporting requirements of paragraphs (c)(2) and (c)(3) according to the following schedule:

(A) Within 1 month from the end of the compliance year, submit a monitoring, reporting, and recordkeeping plan specifying the use of CEMS;

(B) During the shorter of the first twelve months from the end of the compliance year or until the facility complies with paragraphs (c)(2) and (c)(3), the Facility Permit holder shall comply with the monitoring requirements of paragraph (f)(3) of this rule; and

(C) Within one year from the end of the compliance year, comply with paragraphs (c)(2) and (c)(3) and have appropriate direct monitoring equipment installed and certified pursuant to Appendix A.

(9) Infrequently-Operated Major SOx Source

Subparagraphs (c)(2)(A) and (c)(2)(B) shall not apply to a major SOx source if the Facility Permit holder complies with the following requirements.

(A) The Facility Permit holder submits an application for each major SOx source to classify such source to be an infrequently-operated major SOx source, demonstrating to the satisfaction of the Executive Officer that such source will not be operated more than 30 days in the current or next compliance year, and receives written approval from the Executive Officer. The Executive Officer shall further not approve an application to classify a major source to be an infrequently-operated major SOx source if such source had been previously classified as an infrequently-operated source for any time during the 18 calendar months prior to the filing date of the application.

(B) The Facility Permit holder accepts and complies with all permit conditions imposed to ensure compliance with subparagraphs (c)(9)(C) and (c)(9)(D).

(C) The Facility Permit holder shall comply with all of the following requirements:

(i) While the infrequently-operated major SOx source is operating, the Facility Permit holder shall comply with provisions under subparagraphs (c)(2)(A), (c)(2)(B), or Rule 2011, Appendix A, Chapter 2, Paragraph B.6. - Alternative Data Acquisition Using Reference Methods.

(ii) While the infrequently-operated major SOx source is not operating, the Facility Permit holder shall disconnect fuel or process feed line(s) and place flanges at both ends of the disconnected line(s) and install, maintain, and operate a monitoring device, which has been approved by the Executive Officer, to provide a continuous positive indicator of the operational status of the source to the remote terminal unit (RTU) for the purposes of demonstrating the source is not operating and for preparing emissions reports.

(D) A source, which has been approved as an infrequently-operated source pursuant to paragraph (c)(9), shall not be operated more than 30 days in any compliance year unless the following requirements are met:

(i) The Facility Permit holder shall provide written notification to the Executive Officer that the infrequently-operated major SOx source will be operated more than 30 days in any compliance year on or before the day that such source will be operated in excess of 30 days in any compliance year.

(ii) The infrequently-operated Major SOx source complies with subparagraph (c)(2)(A) or (c)(2)(B) on the thirty first day of operation in any compliance year except if that source qualifies for a one-time only CEMS certification period as provided in subparagraph (c)(11).

(10) Non-Operated Major SOx Source

Subparagraphs (c)(2)(A) and (c)(2)(B) shall not apply to a major SOx source if the Facility Permit holder complies with the following requirements.

(A) The Facility Permit holder submits an application for each major

SOx source to classify such source to be a non-operated major SOx source, demonstrating to the satisfaction of the Executive Officer that such source will not be operated in the current or next compliance year, and receives written approval from the Executive Officer. The Executive Officer shall further not approve an application to classify a major source to be a non-operated major SOx source if such source had previously been classified as a non-operated source for any time during the 18 calendar months prior to the filing date of the application.

(B) The Facility Permit holder accepts and complies with all permit conditions imposed to ensure compliance with subparagraphs (c)(10)(C) and (c)(10)(D).

(C) The Facility Permit holder shall comply with the requirements under either subclause (i) or (ii):

(i) The Facility Permit holder shall:

(I) disconnect fuel feed lines and place flanges at both ends of the disconnected lines, and

(II) render the source non-operational by either disconnecting the process feed lines and place flanges at both ends of the disconnected lines or removing a major component of the source necessary for its operation.

(ii) The Facility Permit holder shall monitor the source with an operating CEMS that was certified to monitor emissions from that source in accordance with District Rule 218 - Stack Monitoring or Rule 2011 and Appendix A, and maintain records demonstrating the source's non-operational status as required by either Rule 218 or these rules, whichever is applicable.

(D) A source, which has been approved as a non-operated source pursuant to paragraph (c)(10), shall not be operated until the following requirements are met:

(i) The Facility Permit holder shall provide written notification to the Executive Officer that the source will be operated. The notification shall be made no less than 30 days prior to starting operation of the source.

(ii) The source meets the requirements of subparagraph (c)(2)(A) or (c)(2)(B) no later than 30 calendar days after the start of operation except as provided under paragraph (c)(11). Until the source meets the requirements of subparagraph (c)(2)(A) or (c)(2)(B), emissions shall be determined pursuant to the Missing Data Procedures as specified under Rule 2011, Appendix A, Chapter 2, Subdivision E.

(11) An infrequently-operated or non-operated major SOx source qualifies for a one-time only CEMS certification period if:

(A) the source has never been monitored by a RECLAIM certified CEMS since October 15, 1993, and

(B) the source has been in compliance with paragraph (c)(9) or (c)(10) during the previous 12 months prior to the date the source operates in excess of the applicable operating time limit.

This one-time only CEMS certification period shall commence on the first day of any operation for non-operated major sources and the thirty-first day of any operation for infrequently operated major sources in any compliance year and ends on the date the CEMS is certified or 12 calendar months from the first day of any operation for non-operated major sources and the thirty-first day of any operation for infrequently operated major sources, whichever date is earlier. By the end of this CEMS certification period, the Facility Permit holder shall install, operate, and maintain all required monitoring, reporting, and recordkeeping systems. During this CEMS certification period, the Facility Permit holder shall comply with the monitoring, reporting, and recordkeeping requirements of paragraphs (f)(2) and (f)(3).

(12) If an approved infrequently-operated or non-operated major SOx source fails to meets the requirements of the applicable paragraph (c)(9) or (c)(10) that source shall no longer be considered an infrequently-operated or non-operated major SOx source, and the facility permit holder of the source shall be considered in violation for each day from the start of the compliance year and emissions shall be determined as if the source had been operating from the start of the compliance year according to Missing Data Procedures as specified under Rule 2011, Appendix A, Chapter 2,

clause (E)(1)(d)(iii), except for those days in which the Facility Permit holder can conclusively prove that the source has not been operated.

(d) SO_X Process Unit

(1) SO_X process unit is any piece of SO_X emitting equipment which is not a major SO_X source or a piece of equipment designated in Rule 219 - Equipment Not Requiring a Written Permit Pursuant to Regulation II.

(2) The Facility Permit holder of a SO_X process unit shall comply with paragraphs (c)(2) and (c)(3) for any SO_X process unit, or elect to comply with the following:

(A) install, maintain, and operate a totalizing fuel meter and/or timer, or any device approved by the Executive Officer or designee to be equivalent in accuracy, reliability, reproducibility and timeliness, for the SO_X process unit, to measure quarterly fuel usage or other applicable measured variables specified in Table 2011-1, and Appendix A, Chapter 3, Table 3-A; and

(B) report quarterly mass emission of SO_X to the District Central Station 30 days after the end of each of the first three quarters and 60 days after the last quarter of a compliance year for each process unit using a modem, the District Internet Web Site, or any reporting device approved by the Executive Officer to be equivalent in accuracy, reliability, and timeliness; and

(C) accept the emission factor as specified pursuant to paragraphs (d)(3), (d)(4), or (d)(5) in the Facility Permit, as the sole method for determining mass emissions for all purposes, including, but not limited to, determining:

(i) compliance with the annual allocations;

(ii) excess emissions;

(iii) the amount of penalties; and

(iv) fees.

(3) Starting January 1, 1994 for Cycle 1 facilities, and July 1, 1994 for Cycle 2 facilities, calculations of mass emissions from each process unit shall be based upon the emission factor specified in Rule 2002. The emission factor for each process unit will be specified in the Facility Permit and will remain valid unless amended by the Executive Officer or designee pursuant to paragraphs (d)(4) or (d)(5).

(4) A Facility Permit holder may apply to the Executive Officer or designee to amend the emission factor to an equipment or category specific emission rate in the Facility Permit for a SO_X process unit at any time. If the applicant demonstrates to the Executive Officer or designee that the equipment or category specific emission rate is reliable, accurate, and representative for the purpose of calculating SO_X emissions, the Executive Officer or designee will amend the Facility Permit to incorporate the equipment or category specific emission rate. The equipment or category specific emission rate shall take effect prospectively from the date the Facility Permit is amended.

(5) The Executive Officer or designee may amend the Facility Permit at any time to specify an equipment or category specific emission rate for a SO_X process unit if the equipment or category specific emission rate is determined to be more reliable, accurate, or representative of that unit's emissions than the previous emission factor stated in the Facility Permit. The equipment or category specific emission rate shall take effect prospectively from the date the Facility Permit is amended.

(e) General Requirements

(1) A Facility Permit holder shall at all times comply with all requirements specified in subdivisions (c), (d), (e), (f) and (g) for monitoring, reporting and recordkeeping, including but not limited to, measuring, reporting, timesharing, determining mass emissions, and installing, maintaining or operating monitoring, measuring, and reporting devices, in accordance with the applicable requirements set forth in Appendix A.

(2) The monitoring system and the applicable method for determination of mass emissions for each SO_X source or process unit will be specified in the Facility Permit, in accordance with the applicable requirements set forth in Appendix A.

(3) The time-sharing of CEMS or equivalent devices among SO_X sources may be allowed by the Executive Officer or designee in accordance with the requirements for time-sharing specified in Appendix A. In such cases, the Executive Officer or designee will specify conditions in the Facility Permit upon which time-sharing may occur.

(4) Any monitoring system certified prior to October 15, 1993 requiring a change to its full scale span range in order to meet the certification

requirements set forth in Appendix A, shall be recertified by the District in accordance with the recertification requirements specified in Chapter 2, Section B.15, in Appendix A.

(5) The Executive Officer or designee may at any time require a Facility Permit holder to use a specific monitoring and reporting system if the Executive Officer or designee determines that the elected system is inadequate to accurately determine mass emissions.

(6) The sharing of totalizing fuel meters may be allowed by the Executive Officer or designee if the process units served by the fuel meters have the same emission factor.

(7) A Facility Permit holder of any SO_X major source, process unit, or piece of equipment which is exempt from permit requirements pursuant to Rule 219 - Equipment Not Requiring a Written Permit Pursuant to Regulation II, shall determine SO_X emissions according to the methodology specified in Appendix A. Process units, or pieces of equipment exempt from permit requirements pursuant to Rule 219 shall report such SO_X emissions in the Quarterly Certification of Emissions required by Rule 2004 - Requirements. Emissions from equipment exempt from permit requirements pursuant to Rule 219 shall also be reported quarterly to the District Central Station by the end of the quarterly reconciliation period as specified under Rule 2004(b) – Compliance Period and Certification of emissions. Alternatively, these emissions may be reported using the District Internet Web Site.

(8) A Facility Permit holder shall at all times comply with all applicable requirements specified in this rule and Appendix A for monitoring, reporting and recordkeeping of operations of RECLAIM SOx sources that are not included in the Facility Permit so as to determine and report to the District Central Station the quarterly emissions from these sources by the end of the quarterly reconciliation period as specified under Rule 2004(b). These sources may include, but are not limited to, rental equipment, equipment operated by contractors, and equipment operated under a temporary permit or without a District permit. In addition, the Facility Permit holder shall include emissions from these sources in the Quarterly Certification of Emissions required by Rule 2004.

(f) Compliance Schedule

(1) Facilities with existing CEMS and fuel meters as of October 15, 1993 shall continue to follow recording and reporting procedures required by District rules and regulations in effect immediately prior to October 15, 1993 until December 31, 1994 for Cycle 1 facilities and June 30, 1995 for Cycle 2 facilities.

(2) Between January 1, 1994 and December 31, 1994 for Cycle 1 facilities and between July 1, 1994 and June 30, 1995 for Cycle 2 facilities, interim emission reports shall be submitted to the District by the Facility Permit holder. The interim reports shall comply with all of the data requirements of this rule and Appendix A, except that the reporting frequency shall be monthly for major sources, and quarterly for process units. Such reports shall be submitted by the fifteenth (15^{th}) day of each month for major sources, and as specified in paragraph (b)(2) of Rule 2004 - Requirements, for process units.

(3) A Facility Permit holder shall install, maintain and operate a totalizing fuel meter or any device approved by the Executive Officer or designee to be equivalent in accuracy, reliability, reproducibility, and timeliness for each major source and process unit by January 1, 1994 for Cycle 1 facilities, and July 1, 1994 for Cycle 2 facilities, except that sharing of such devices may be allowed, pursuant to paragraph (e)(6) of this rule.

(4) All required or elected monitoring and reporting systems specified in subdivision (c) and (d) shall be installed no later than December 31, 1994 for Cycle 1 facilities and June 30, 1995 for Cycle 2 facilities. Monitoring, Reporting, and Recordkeeping (MRR) Forms will be provided by the Executive Officer or designee by November 15, 1993 for Cycle 1 facilities and April 15, 1994 for Cycle 2 facilities. The information required on such MRR forms shall be submitted no later than December 31, 1993 for Cycle 1 facilities and June 30, 1994 for Cycle 2 facilities.

(5) The Facility Permit holder of an existing facility which elects to enter RECLAIM or a facility which is required to enter RECLAIM shall install all required or elected monitoring, reporting and recordkeeping systems no later than 12 months after entry into RECLAIM. During the 12 months prior to the installation of the required or elected monitoring, reporting

and recordkeeping systems, the Facility Permit holder shall comply with the monitoring, reporting, and recordkeeping requirements of paragraphs (f)(2) and (f)(3) of this rule.

(6) The Facility Permit holder which installs a new major SOx source at an existing facility shall install, operate, and maintain all required monitoring, reporting and recordkeeping systems no later than 12 months after the initial start up of the major SOx source. During the interim period between the initial start up of the major SOx source and the provisional certification date of the CEMS, the Facility Permit holder shall comply with the monitoring requirements of paragraphs (f)(2) and (f)(3) of this rule.

(g) Recordkeeping

The Facility Permit holder of a major SO_X source or SO_X process unit shall maintain all data required to be gathered, computed or reported pursuant to this rule and Appendix A for three years after each APEP report is submitted to the District except that all data gathered or computed for intervals of less than 15 minutes shall be maintained for a minimum of 48 hours. The Facility Permit holder of a major SOx source which is required to comply with 40 CFR Part 75 may instead opt to comply with the applicable recordkeeping requirements under 40 CFR Part 75. All records shall be made available to the District staff upon request.

(h) Source Testing

All required source testing shall comply with applicable District Source Test Methods 1.1, 1.2, 2.1, 2.2, 2.3, 3.1, 4.1, 6.1, 100.1 and 307-91; ASTM Methods D3588-91, D4891-89, D1945-81, D4294-90, and D2622-92, and EPA Method 19.

(i) Exemption

The provisions of this rule shall not apply to gas flares.

(j) Appeals

The Facility Permit holder of a facility which has established Super Compliant status shall have a maximum of ten calendar days from the receipt of notification that the facility is no longer Super Compliant in which to file an appeal of such finding to the District Hearing Board in accordance with the requirements of Rule 216.

(k) Appendix A

All provisions of Appendix A are incorporated herein by reference.

Attachment: Appendix A - "Protocol for Monitoring, Reporting and Recordkeeping for Oxides of Sulfur (SO_X) Emissions."

Table 2011-1

MEASURED VARIABLES AND REPORTED DATA FOR SO_X SOURCES

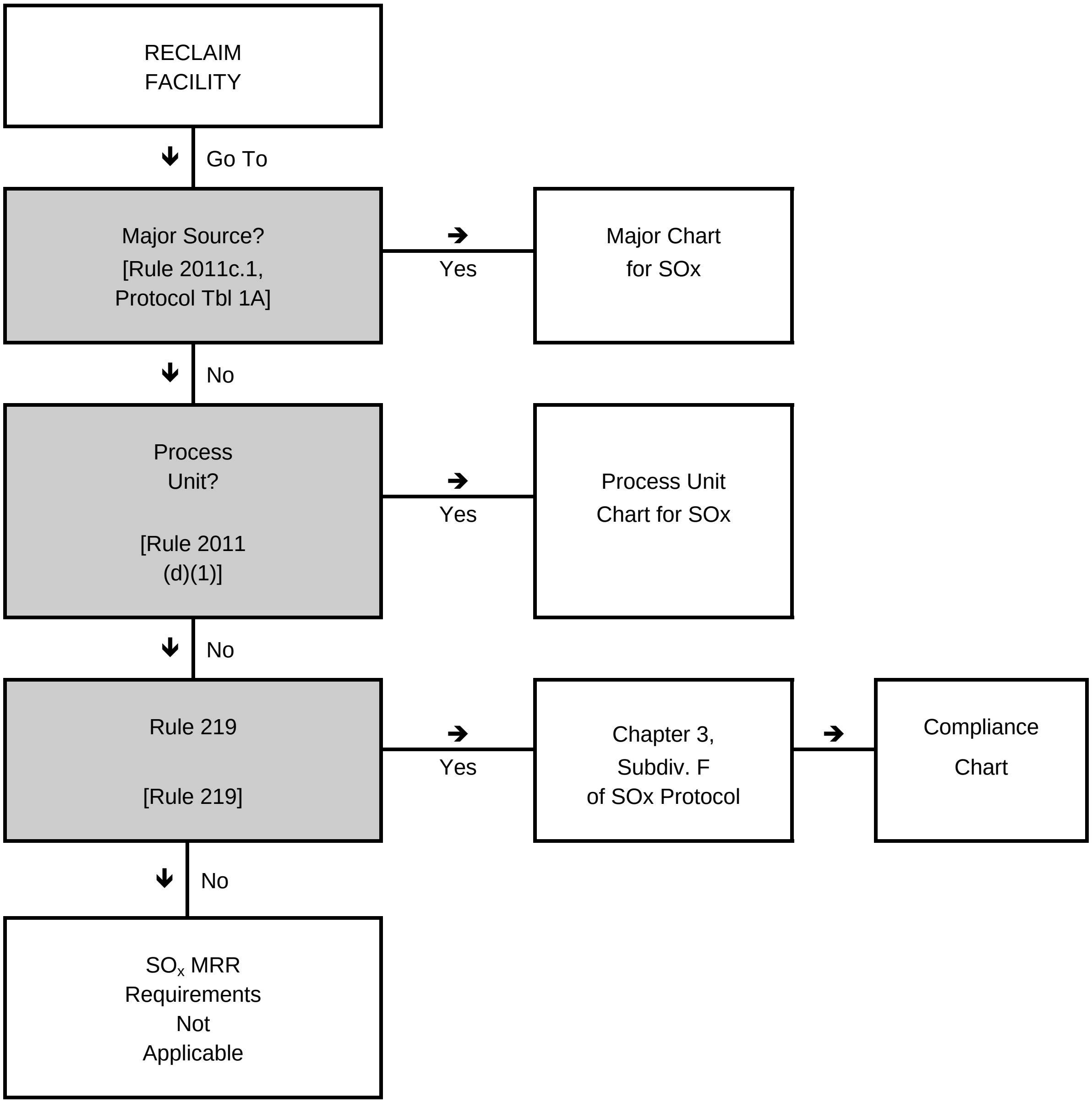
SO_X SOURCES	**MEASURED VARIABLES**	**RECORDING FREQUENCY**	**REPORTED DATA**	**TRANSMITTING/ REPORTING FREQUENCY**
All sources subject to Paragraphs (c)(2) and (c)(3)	Stack SO_X concentration, Exhaust flow rate, and Status codes OR SO_X concentration, Stack O_2 concentration, Fuel flow rate and Status codes OR Fuel sulfur content, Fuel flow rate, and Status codes	Once every 15 minutes	Total daily mass emissions from each source Daily status codes	Once a day for transmitting/ once a month for reporting
SO_X Process units subject to Paragraph (d)(2)	Fuel usage OR Operating time and Production/ Processing/ Feed rate	Quarterly	Total quarterly mass emissions	Once a quarter for reporting

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

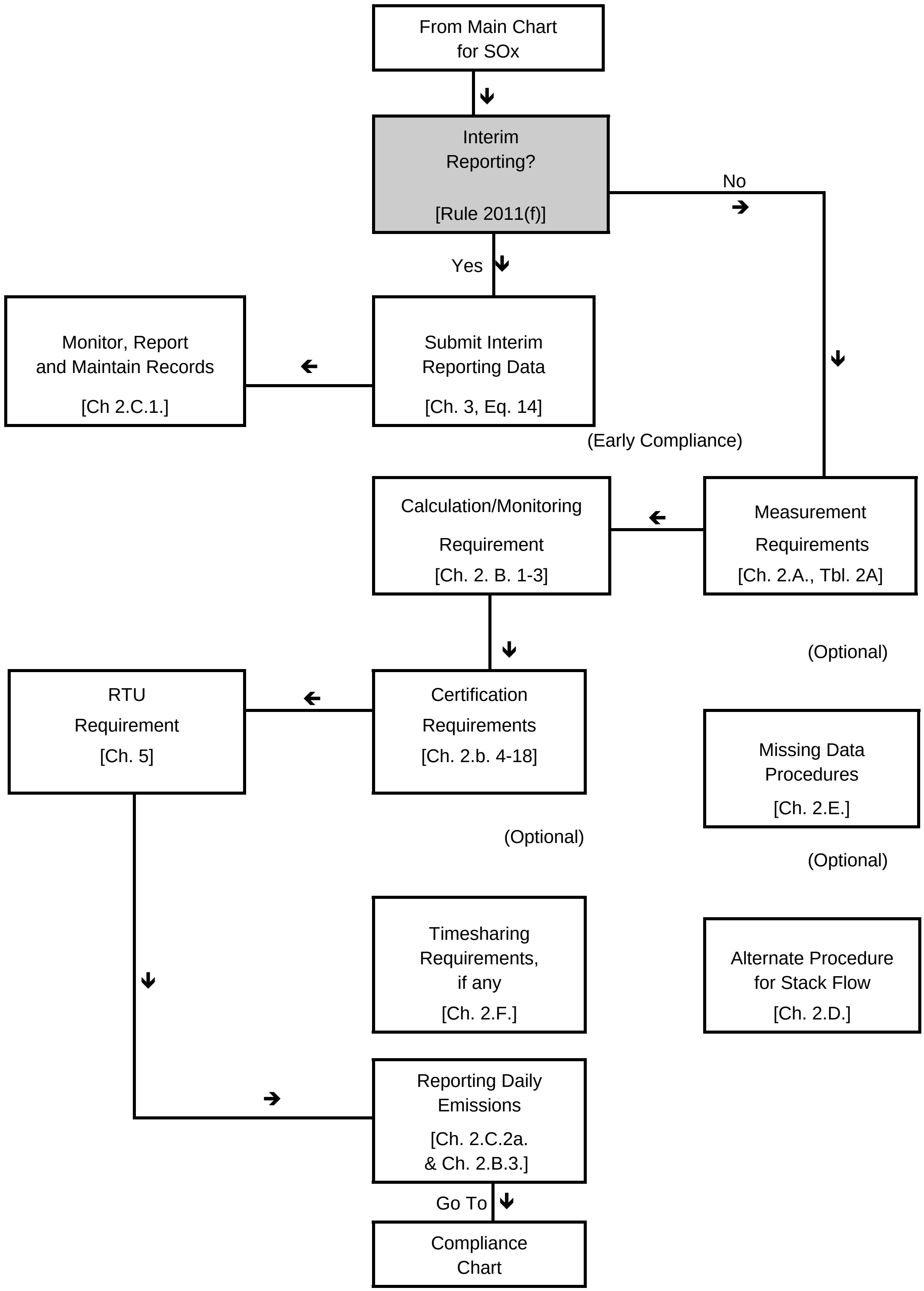
RULE 2011 PROTOCOL - APPENDIX A

Rule 2011 - Protocol for Monitoring, Reporting, and Recordkeeping for Oxides of Sulfur (SO_X) Emissions

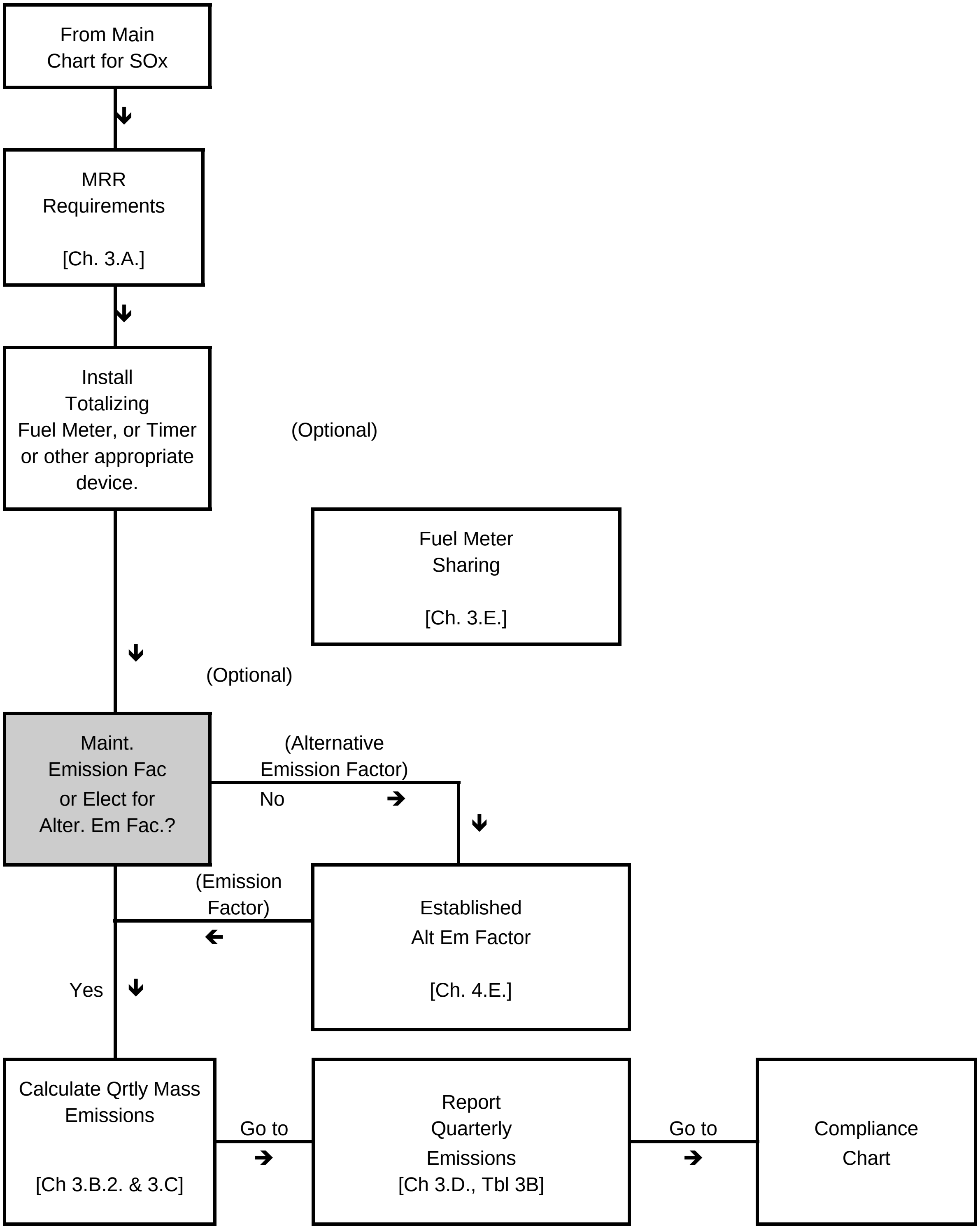
Main Chart for SOx



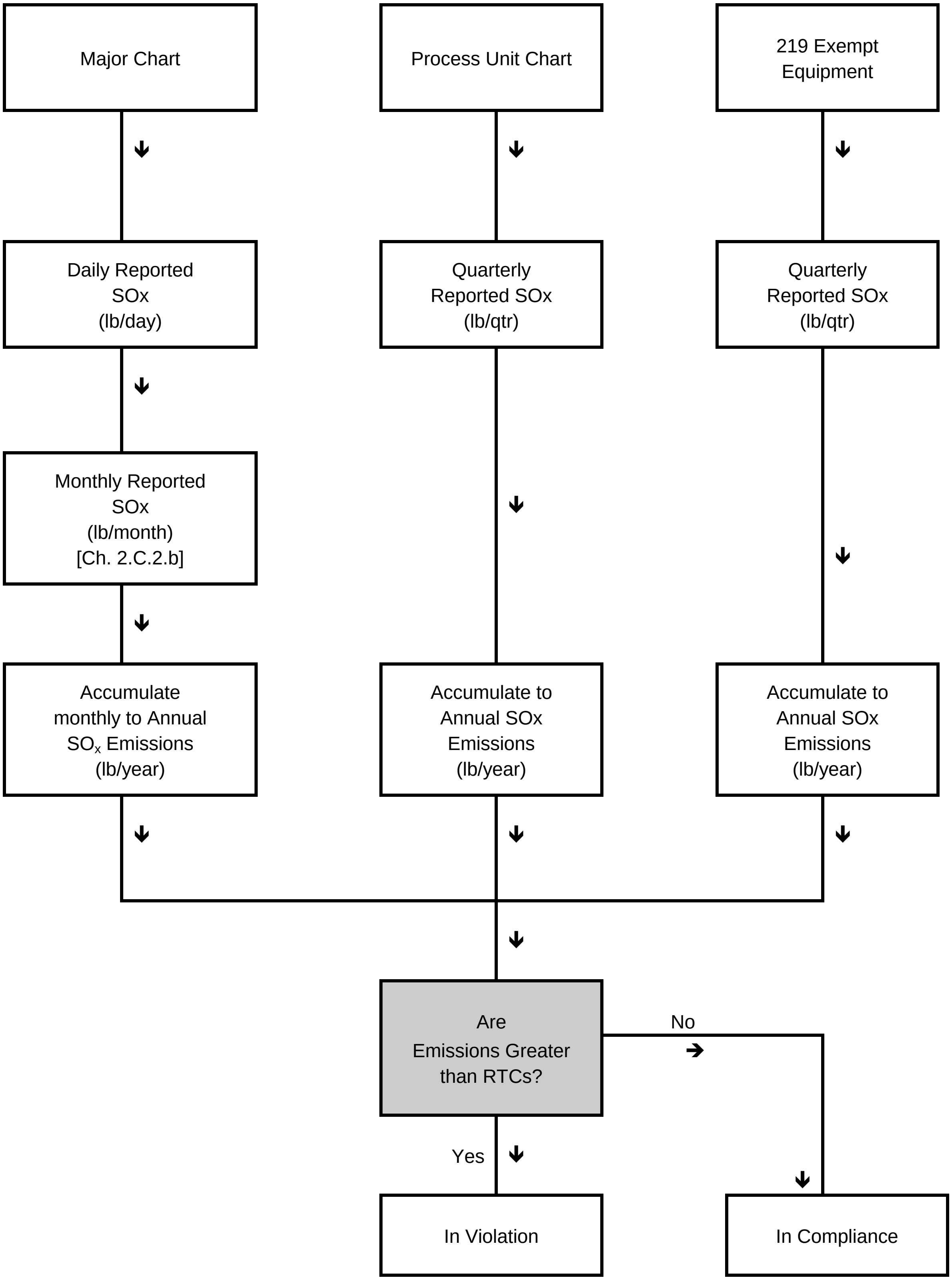
Major Chart for SOx



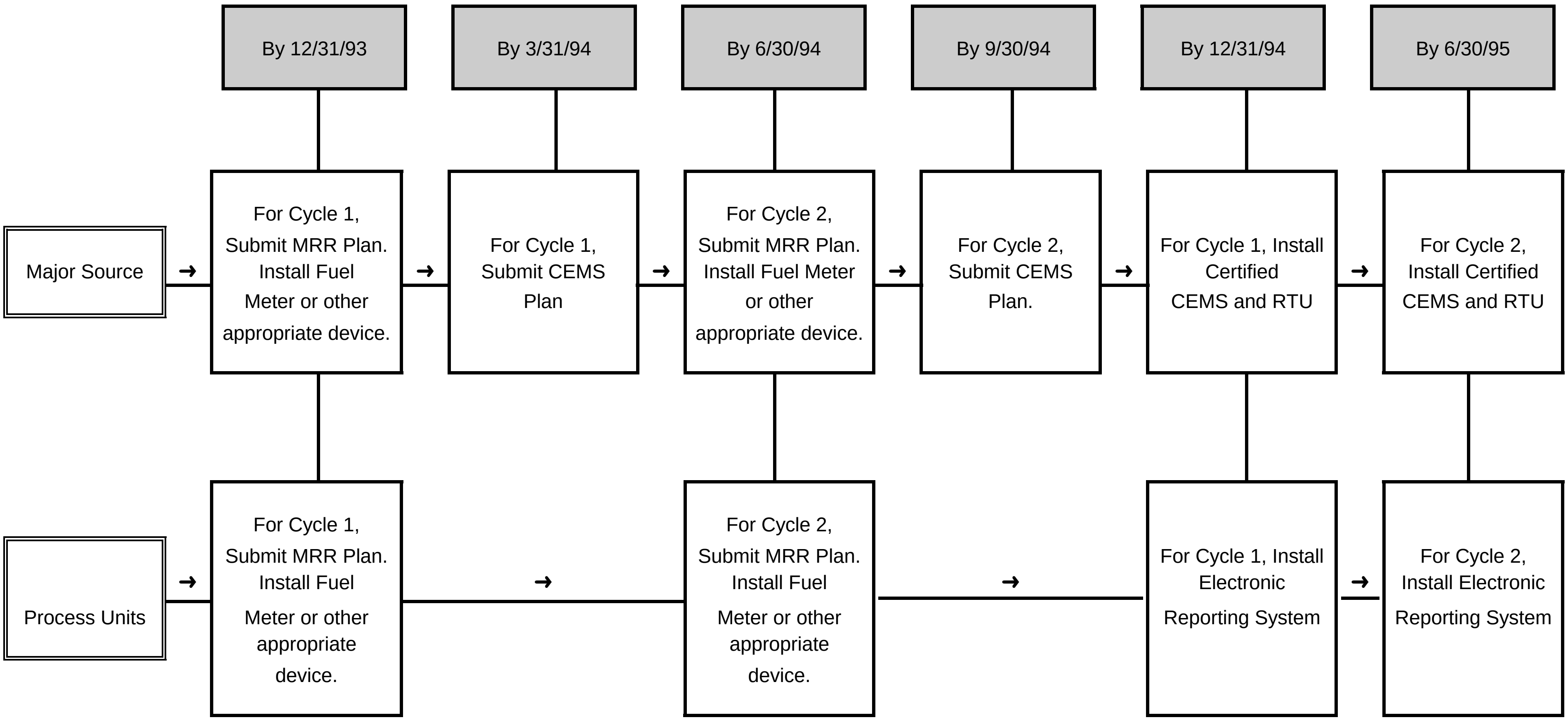
Process Chart For SOx



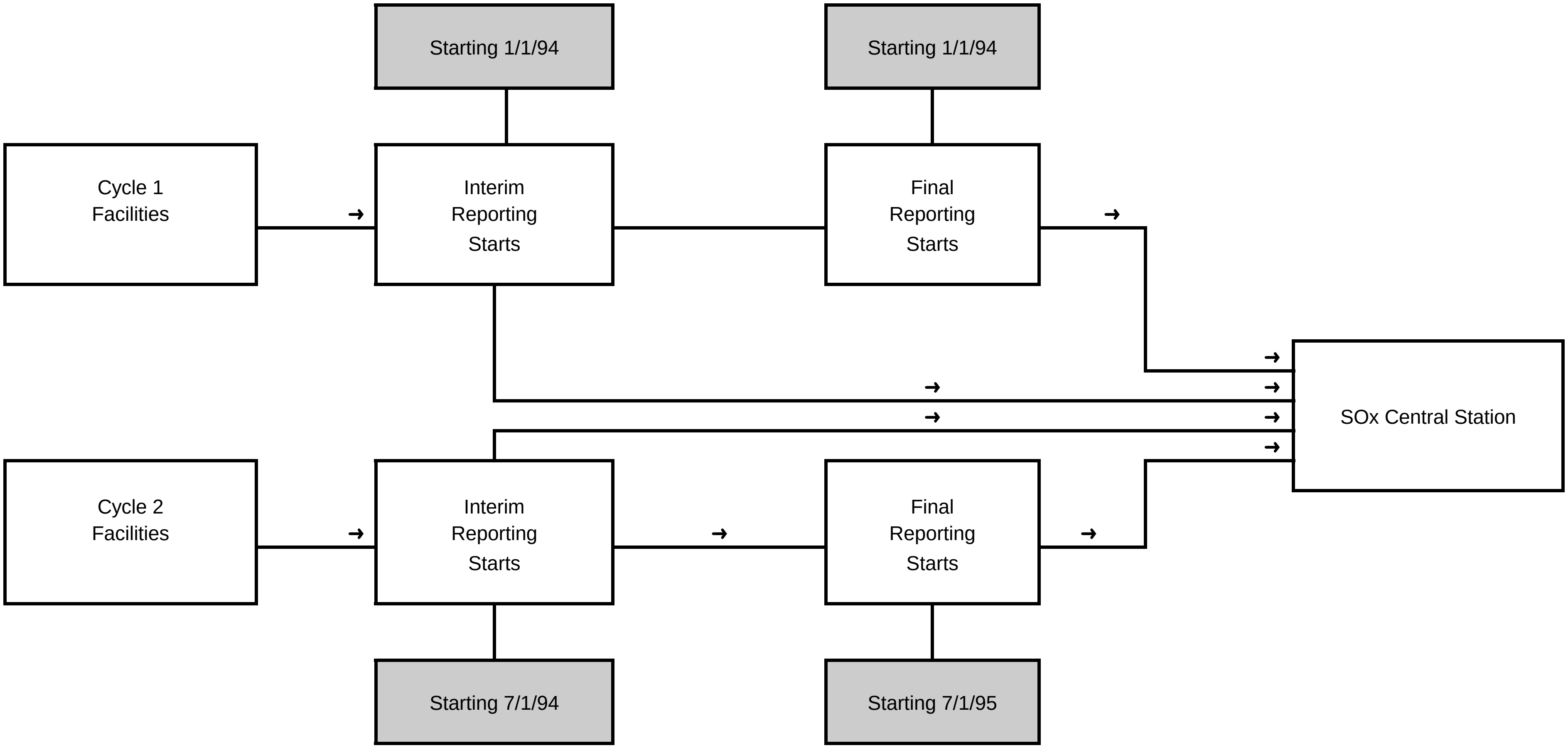
Compliance Chart For SOx



SOx Timeline Chart For Plan, Certification And Installation



Timeline for SO_x Emission Reporting



Note 1: The Facility Permit Holder shall submit a variance to the hearing board, if any of the deadlines are not met.
Note 2: Refer to Chapter 6 of SOx Protocol for remedial actions required when the loss of categorization status occurs.

RULE 2011 PROTOCOL- CHAPTER 1

OVERVIEW

This document provides the technical specifications for normally operated RECLAIM sources subject to District Rule 2011 "Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Sulfur (SO_x) Emissions". District Rule 2011 divides sources into three categories - major sources, SO_x process units and Rule 219 - "Equipment Not Requiring a Written Permit Pursuant to Regulation II" sources. The one difference in requirements between these source categories is the monitoring approach. A major source shall be monitored by a continuous emissions monitoring system (CEMS) or alternative monitoring system, while a SO_x process unit has the option to be monitored manually based on fuel usage and emission factor.

Oxides of sulfur (SOx) emissions shall be composed of sulfur dioxide (SO_2) emissions. No later than June 30, 1994 the Executive Officer will determine the feasibility for estimating sulfur trioxide (SO_3) emissions as a function of SO_2 emissions for a petroleum refinery fluid catalytic cracking unit. If the Executive Officer determines that the surrogate approach is feasible then a unit-specific protocol will be developed by the Executive Officer by August 31, 1994. The Facility Permit holder of a petroleum refinery fluid catalytic cracking unit shall apply the protocol prospectively to determine SOx emissions on both SO_2 and SO_3 emissions. If the Executive Officer determines that the surrogate approach is not feasible then SOx emissions shall continue to be based only on SO_2 emissions.

These SO_x source categories also differ in the way in which they transmit data to the District's Central Station and the reporting frequency. Major sources shall electronically transmit the data via an RTU on a daily basis. In addition, aggregated SO_x emissions from all major sources must be submitted in a Monthly Emissions Report. SO_x process units have the option to report SO_x emissions as part of the Quarterly Certification of Emissions required by Rule 2004 - Requirements.

The criteria for determining the major source applicability is presented in Table 1-A. A SO_x process unit is one or more piece(s) of equipment which is not a major source, provided that each equipment in a process unit is subject to an identical emission factor specified in subdivision (d) of Rule 2011.

The Facility Permit will limit mass emissions in accordance with the following relationship:

$$\sum E_{CEMS} + \sum E_{EF} + \sum E_{219} \leq \text{RTCs}$$

where:

$\sum E_{CEMS}$	=	sum of facility emissions monitored by CEMS or alternative monitoring system
$\sum E_{EF}$	=	sum of facility emissions from process units subject to emission factors $(EF)_{pu}$
$\sum E_{219}$	=	sum of facility emissions from equipment exempt under Rule 219, subject to emission factor $(EF)_{219}$.
RTC	=	RECLAIM Trading Credit held by the Facility Permit holder

The fuel usage for any process unit or equipment exempt under Rule 219 shall not exceed the value determined in accordance with the following relationship:

$$\Sigma\,(FxEF)_{pu} + \Sigma\,(FxEF)_{219} < RTC - \Sigma\,E_{CEMS}$$

where:

F = Fuel usage for the process unit or equipment exempt under Rule 219

The Facility Permit holder shall document the duration of operating time of any rental equipment or equipment operated by a contractor at the RECLAIM facility. Emissions generated at the RECLAIM facility by either rental equipment or equipment not listed or required to be listed under the Facility Permit and operated by a contractor, which exceeds 72 hours of operation in a quarter, shall be determined and reported by the Facility Permit holder according to the applicable methodology specified for each major source or process unit or Rule 219 exempt equipment.

The duration of operating time and emissions from equipment operated by contractors need not be monitored or reported if the equipment is exclusively used for the following purposes that do not contribute to the manufacturing process:

- Landscaping and grounds maintenance;
- Maintenance and repair of structure, equipment, and their appurtenances;
- Construction and demolition; or
- Environmental investigation, testing, and remediation.

A Facility Permit holder subject to the requirements of Rules 2005(b)(2) and 2005(f) shall monitor and report applicable emissions as specified in Rule 2005(b)(2)(C). The emissions from these activities shall be determined according to the methodology specified for process units.

Emissions resulting from equipment during breakdowns shall be quantified in a manner specified by the Executive Officer in accordance with the following criteria:

1. When emissions are within the valid monitoring range of the monitor, the emissions shall be calculated based on the methodology pursuant to Chapters 2 and 3.
2. When emissions exceed the valid monitoring range of the monitor, the emissions may be calculated based on any one or more of the following:
   - Source test data
   - Fuel flow or throughput
   - Sulfur content of fuel during the breakdown period
   - Emission factor
   - Control efficiencies
   - Any other relevant data that may be used to determine emissions during breakdown.

This document has been divided into chapters addressing the various compliance aspects of Rule 2011. A summary of each chapter follows:

CHAPTER 2: MAJOR SOURCES - CONTINUOUS EMISSION MONITORING SYSTEM (CEMS)

Chapter 2 describes the methodologies for measuring and reporting SO_X emissions from major sources. If a major source category is applicable, then the Facility Permit holder shall be required to comply with the performance standards associated with a CEMS or an equivalent monitoring device.

For major sources, measurement and reporting requirements apply to variables used to calculate the SO_X emissions as well as the variables used to track the operation of basic, control, and monitoring equipment.

Unless specifically exempted by Rule 2011, the Facility Permit holder shall measure and record all applicable variables as specified in Table 2-A.

Several important aspects of Chapter 2 include:

- equations describing the method used to calculate SO_X emissions,
- operational requirements,
- obtaining valid data points,
- alternative data acquisition methods,
- accuracy requirements,
- quality assurance procedures,
- missing data procedures,
- final and interim reporting procedures, and
- timesharing

CHAPTER 3: PROCESS UNITS - PERIODIC REPORTING AND RULE 219 EQUIPMENT

Chapter 3 describes the measuring and reporting requirements for the SO_X process unit category and equipment exempt from permit under Rule 219. SO_X process units which comprise of one or more pieces of equipment in accordance with Rule 2011 shall base emission calculations primarily on fuel consumption or operating time in conjunction with the emission factor. The requirements and procedures for an emission factor and election conditions for an alternative emission factor shall apply to process units. These SO_X process units may include equipment that are lumped together only if the units have the same emission factor.

Important aspects of Chapters 3 include equations describing the method used to calculate SO_X emissions and reporting procedures for process units as well as determining SO_X emissions from equipment exempt under Rule 219.

CHAPTER 4: PROCESS UNITS - SOURCE TESTING

This Chapter presents a brief description of the required test methods for determining alternative emission factors for process units .

CHAPTER 5: REMOTE TERMINAL UNITS - ELECTRONIC REPORTING

Once the variables for determining emissions and equipment operations have been measured, the measured data would be stored at the facility. In addition, selected measured and calculated data would be transmitted to the District's Central Station Computer. This storing and transmitting of data for major sources shall be performed by the remote terminal unit (RTU).

Chapter 5 specifies tasks and characteristics required of the RTU as well as a guide for providing the required software/hardware for the RTU. In addition, this chapter serves as a:

- functional guideline for operating requirements of the RTU, and
- information source concerning RTU hardware/software procurement, configuration, installation, maintenance, and compatibility with the CEMS and the District's Central Station.

TABLE 1-A
Criteria for Determining Major SO_x Source Category

- Any petroleum refinery fluid catalytic cracking units;
- Any tail gas unit;
- Any sulfuric acid production unit;
- Any equipment that burns refinery, landfill, and sewage digester gaseous fuels, except gas flare;
- Any existing equipment using SO_X CEMS, or equivalent monitoring device, or required to install such monitoring device under District rules to be implemented as of October 15, 1993
- Any SO_X source or process unit elected by the Facility Permit holder or required to be monitored with a CEMS, or equivalent monitoring device; and
- Any SO_X source or process unit for which SO_X emissions reported pursuant to Rule 301 were equal to or greater than 10 tons/yr for any calendar year from 1987 to 1991, inclusive, excluding any SO_X source or process unit which has reduced SO_X emissions to below 10 tons per year to January 1, 1994.

7/15/05

RULE 2011 PROTOCOL- CHAPTER 2

MAJOR SOURCES - CONTINUOUS EMISSION MONITORING SYSTEM (CEMS)

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CHAPTER 2 - MAJOR SOURCES - CONTINUOUS EMISSION MONITORING SYSTEM (CEMS)

The criteria for determining the applicable SO_X RECLAIM category for a specific piece of equipment is presented in Table 1-A for a major source. If a major source category is applicable to this equipment, then the Facility Permit holder shall be required to comply with the performance standards associated with a CEMS (Continuous Emission Monitoring System) or an approved Alternative Monitoring System (AMS).

The Facility Permit holder of a source that is required to install CEMS may request the Executive Officer to approve an alternative monitoring device (or system components) to quantify emissions of SO_X. The applicant shall demonstrate to the Executive Officer that the proposed alternative monitoring device is at a minimum equivalent in relative accuracy, precision, reliability, and timeliness to a CEMS for that source, according to the criteria specified in 40 CFR Part 75 Subpart E. In lieu of the criteria specified in 40 CFR Part 75 Subpart E, substitute criteria is acceptable if the applicant demonstrates to the Executive Officer that the proposed alternative monitoring device is at minimum equivalent in relative accuracy, precision, reliability, and timeliness to a CEMS for that source. Upon approval by the Executive Officer, the substitute criteria shall be submitted to the federal Environmental Protection Agency as an amendment to the State Implementation Plan (SIP).

Chapter 2 describes the methodologies for measuring, monitoring, and reporting emissions from major sources. All major sources shall be monitored by a continuous emissions monitoring system (CEMS) or an alternative monitoring system (AMS). The required equipment-specific variables, both measured and reported, to be monitored are found in Tables 2-A and 2-B, respectively.

Another important requirement of major SO_X sources is the way in which they transmit data to the District's Central Station and the reporting frequency. Major sources shall electronically transmit the data via an RTU on a daily basis. In addition, the aggregated SO_x emissions from all major sources must be submitted in a Monthly Emissions Report.

During the interim period, January 1, 1994 through December 31, 1994 for Cycle 1 facilities and July 1, 1994 through June 30, 1995 for Cycle 2 facilities mass emissions for major sources shall be determined using emission factors referenced in Table 2 of Rule 2002.

Other important aspects covered in this chapter include missing data procedures and CEMS timesharing requirements.

A. MEASUREMENT REQUIREMENTS

1. Between January 1, 1994 and December 31, 1994 (Cycle 1 facilities) and between July 1, 1994 and June 30, 1995 (Cycle 2 facilities), major sources shall be allowed to use an interim reporting procedure to measure and record SO_X emissions on a monthly basis and may be extracted from SO_X emission data gathered by existing District certified continuous emissions monitoring system (CEMS). Chapter 2, Subdivision C, Paragraph 1 specifies the requirements for this interim period. On and after January 1, 1995 (Cycle 1 facilities) and July 1, 1995 (Cycle 2 facilities), the Facility Permit holder of each major source shall report a daily average of SO_x emission by 5:00 p.m. of the following day and comply with all other applicable requirements (except Chapter 2, Subdivision C, Subparagraph 1) specified in this chapter.

2. The Facility Permit holder shall by March 31, 1994 for Cycle 1 facilities and September 30, 1994 for Cycle 2 facilities, submit a CEMS plan to the Executive Officer for approval. The plan shall contain at a minimum the following items:

   a. A list of all major sources which will have CEMS installed.

   b. Details of all proposed Continuous Emission Monitors as well as the proposed flow monitors for each affected source.

   c. Details of the Quality Control/Quality Assurance Plan for the CEMS.

   d. Proposed range of each CEMS and the expected concentrations of pollutants for each source.

   e. Date by which purchase order for each system will be issued.

   f. Construction schedule for each system, and date of completion of the installation.

   g. Date by which CEMS certification test protocol will be submitted to the District for approval for each system.

   h. Date by which certification tests will be completed for each system.

   i. Date by which certification test results will be submitted for review by the District, for each system.

   j. Any other pertinent information regarding the installation and certification for each system.

If a CEMS Plan is disapproved in whole or in part, the District staff will notify the Facility Permit holder in writing and the Facility Permit holder shall have 30 days from the date it receives the notice from the District to resubmit its plan.

3. The Facility Permit holder of each major SO_X equipment shall install, calibrate, maintain, and operate an approved CEMS to measure and record the following:

   a. Sulfur oxide concentrations in the gases discharged to the atmosphere from affected equipment.

   b. Oxygen concentrations, at each location where sulfur oxide concentration are monitored, if required for calculation of the stack gas flow rate.

   c. Stack gas volumetric flow rate. An in-stack flow meter may be used to determine mass emissions to the atmosphere from affected equipment, except:

      i. when more than one affected piece of equipment vents to the atmosphere through a single stack and there is no approvable means of determining emissions from each piece of equipment, or

ii. during periods of low flow rates when the flow rate is no longer within the applicable range of the in-stack flow meter.

d. In lieu of complying with Chapter 2, Subdivision A, Paragraph 1, Subparagraph c, the Facility Permit holder shall calculate stack gas volumetric flowrate using one of the following alternate methods:

i. Heat Input

If heat input rate is needed to determine the stack gas volumetric flow rate, the Facility Permit holder shall include in the CEMS calculations the F factors listed in 40 CFR Part 60, Appendix A, Method 19, Table 19-1. The Facility Permit holder shall submit data to develop F factors when alternative fuels are fired and obtain the approval of the Executive Officer for use of the F factors before firing any alternative fuels.

ii. Oxygen Mass Balance

Flow rate can be determined using oxygen mass balance as approved through a plan submitted to and approved by the Executive Officer, or

iii. Nitrogen Mass Balance

Flow rate can be determined using nitrogen mass balance as approved through a plan submitted to and approved by the Executive Officer.

The Facility Permit holder shall measure and record all variables necessary for the method chosen to calculate stack gas volumetric flowrate.

e. Fuel gas flow rate if the CEMS uses the fuel gas flow rate and the sulfur content of the fuel gas to determine the sulfur oxide emissions.

f. Sulfur content of the fuel if the CEMS uses the fuel input rate and the sulfur content of the fuel gas to determine the sulfur oxides emission rate.

g. All applicable variables listed in Table 2-A.

h. The Facility Permit holder shall also provide any other data necessary for calculating air contaminant emissions as determined by the Executive Officer.

i. The data generated from a monitoring system for parameters listed in Subparagraphs a, b, c, d, e, and f of Chapter 2, Subdivision A, Paragraph 3 shall be recorded by both (1) the remote terminal unit (RTU) and (2) strip chart recorder or electronic recorder. The RTU shall be capable of producing a printout of the stored data upon request from the Executive Officer or designee. The strip chart recorder or alternative electronic recorder shall be located in parallel to the RTU. The strip chart recorder or alternative electronic recorder shall receive data independent of the RTU and serve as an independent tool for verifying data archived in the RTU or sent to the District Central SOx Station.

If a strip chart recorder is used, the strip chart shall have a minimum chart width of 10 inches, a readability of 0.5% of the span, and a minimum of 100 chart divisions. Alternatively, if an electronic recorder is used, the recorder shall be capable of writing data on a medium that is secure and tamper-proof. Possible media include, but are not limited to, "write-once-read-many" type or a data encryption system that does not permit encrypted data files to be altered after they have been created, without making the data inaccessible through standard vendor-provided decryption software, or without leaving traceable evidence of tampering. Also, at a minimum, the real-time sampling frequency of the electronic recorder shall be equal to or greater than the rate of data collection for the RTU. Furthermore, such recorded data shall be readily accessible upon request by the Executive Officer or designee. If software is required to access the recorded data, a copy of the software, and all subsequent revisions, shall be provided to the Executive Officer or designee at no cost. If a device is required to retrieve and provide a copy of such recorded data upon request to the Executive Officer or designee, the Facility Permit holder shall maintain and operate such a device at the facility.

The Facility Permit holder shall specify within the CEMS application, as required under Chapter 2, Subdivision A, Paragraph 2, the type of data recording system to be used in parallel to the RTU.

4. The Facility Permit holder must submit to the District his certification test results and supporting document for each CEMS by December 31, 1994. It must certify that the results show that the CEMS has met all the requirements of the rule if its submission is after August 31, 1994. Upon receipt of the test results and the certification that the CEMS is in compliance, the District will issue a Provisional Approval.

After the Provisional Approval, all the data measured and recorded by the CEMS will be considered valid quality assured data, (retroactive to January 1, 1995) provided that the Executive Officer does not issue a notice of disapproval of final certification. Final certification of the CEMS will be granted if the certification test results show that the CEMS has met all the requirements of the rule.

In the case where the test results show that the CEMS does not meet all the requirements of the rule, the Executive Officer will disapprove the final certification. If this occurs, the previously considered valid data from January 1, 1995 will have to be replaced by data as specified in the "Missing Data" section of the rule. This procedure shall be used until the time that new certification test results are submitted, and the CEMS has received final approval by the District.

5. The variables listed in Table 2-A shall be measured and recorded to track the operation of basic and control equipment independent of measurements made by

the monitoring equipment. The variables found in Table 2-B shall be reported to the District's SO_X Central Station Computer. Alternatives in Table 2-A and 2-B indicated choices which must be specified in the Facility Permit for that equipment.

6. As part of the Facility Permit Application review, the Executive Officer may modify the list of Facility Permit holder-selected variables.

7. Data on Facility Permit holder - selected variables shall be made available to the District staff upon request.

8. Source tests shall be performed by testing firms/laboratories who have received approval from the District by going through the District's laboratory approval program.

9. All Relative Accuracy Test Audits (RATA) shall be performed by testing firms/laboratories who have received approval from the District by going through the District's laboratory approval program.

B. MONITORING SYSTEMS

1. Information Required for Each 15-Minute Interval

All CEMS for affected equipment shall, at a minimum, generate and record the following data points once for each successive 15-minute period on the hour and at equally spaced intervals thereafter:

a. Sulfur oxide concentration in the stack in units of ppmv.

b. Oxygen concentration or carbon dioxide in the stack in units of percent.

c. Volumetric flow rate of stack gases in units of dry or wet standard cubic feet per hour (dscfh or wscfh). For affected equipment standard gas conditions are defined as a temperature at 68°F and one atmosphere of pressure.

d. (i) Fuel flow rates in units of standard cubic feet per hour(scfh) for gaseous fuels or pounds per hour (lb/hr) for liquid fuels if EPA Method 19 is used to calculate the stack gas volumetric flow rate, and

(ii) Fuel type.

e. Sulfur oxide mass emissions in units of lb/hour. The sulfur oxide emissions are calculated according to the following:

$$e_i = a_i \times c_i \times 1.662 \times 10^{-7} \quad \text{(Eq. 1)}$$

where:

e_i = The mass emissions of sulfur oxides (lb/hr),

a_i = The stack gas concentration of sulfur oxide (ppmv),

c_i = The stack gas volumetric flow rate (scfh).

Example Calculation:

$$a_i = 2.7 \text{ ppm}$$
$$c_i = 90{,}000 \text{ scfh}$$
$$e_i = a_i \times c_i \times 1.662 \times 10^{-7}$$
$$e_i = (2.7)(90{,}000)(1.662 \times 10^{-7}) = 0.04 \text{ lb/hr } SO_x$$

When the CEMS uses the heat input rate and oxygen concentration to determine the sulfur oxide emissions, the following equation would be used to calculate the emission of sulfur oxide:

$$e_i = a_i \times [20.9/(20.9 - b_i)] \times 1.662 \times 10^{-7} \times \sum_{j=1}^{r} (F_{dij} \times d_{ij} \times V_{ij}) \qquad \text{(Eq. 2)}$$

where:

- e_i = The mass emissions of sulfur oxide (lb/hr),
- a_i = The stack gas concentration of sulfur oxide (ppmv),
- b_i = The stack gas concentrations of oxygen (%),
- r = The number of different types of fuel,
- F_{dij} = The F factor for each type of fuel, the ratio of the gas volume of the products of combustion to the heat content of the fuel (scf/10^6 Btu),
- d_{ij} = The metered fuel flow rate for each type of fuel measured every 15-minute period,
- V_{ij} = The higher heating value of the fuel for each type of fuel.

The product (d_{ij} x V_{ij}) must have units of millions of Btu per hour (10^6 Btu/hr). Equation 2 may not be used in cases where enriched oxygen is used, non-fuel sources of carbon dioxide are present (e.g., lime kilns and calciners), and the oxygen content of the stack gas is 19 percent or greater.

Example Calculation:

$$e_i = a_i \times [20.9/(20.9 - b_i)] \times 1.662 \times 10^{-7} \times \sum_{j=1}^{r} (F_{dij} \times d_{ij} \times V_{ij})$$

where:

- a_i = 38.9 ppm
- b_i = 5.6%
- F_{dij} = 8710 dscf/10^6 Btu
- d_{ij} = 10,000 dscfh
- V_{ij} = 1394 Btu/dscf
- e_i = $38.9 \times [20.9/(20.9 - 5.6)] \times 1.662 \times 10^{-7} \times [8710/10^6 \times 10000 \times 1394]$
- e_i = 1.1 lb/hr of SO_x

When the CEMS uses the heat input rate and carbon dioxide concentration to determine the sulfur oxide emissions, the following equation shall be used to calculate the emission of sulfur oxide:

$$e_i = (a_i/t_i) \times 100 \times 1.662 \times 10^{-7} \times \sum_{j=1}^{r} (F_{cij} \times d_{ij} \times V_{ij}) \qquad \text{(Eq. 3)}$$

where:

e_i	=	The mass emissions of sulfur oxide (lb/hr).
a_i	=	The stack gas concentration of sulfur dioxide (ppmv).
t_i	=	The stack gas concentrations of carbon dioxide (%).
r	=	The number of different types of fuel.
F_{cij}	=	The carbon dioxide-based dry F factor for each type of fuel, the ratio of the dry gas volume of carbon dioxide to the heat content of the fuel (scf/10^6 Btu).
d_{ij}	=	The metered fuel flow rate for each type of fuel measured every 15-minute period.
V_{ij}	=	The higher heating value of the fuel for each type of fuel.

The product (d_{ij} x V_{ij}) must have units of millions of Btu per hour (10^6 Btu/hr).

Example Calculation:

$$e_i = (a_i/t_i) \times 100 \times 1.662 \times 10^{-7} \times \sum_{j=1}^{r} (F_{cij} \times d_{ij} \times V_{ij})$$

where:

a_i	=	38.9 ppm
t_i	=	11.0%
F_{cij}	=	1040 scf/10^6 Btu
d_{ij}	=	10,000 dscfh
V_{ij}	=	1394 Btu/dscf
e_i	=	(38.9/11.0) x 100 x 1.662 x 10^{-7} x [1040/10^6 x 10000 x 1394]
e_i	=	0.85 lb/hr of SO_x

When the CEMS uses the fuel gas flow rate and the sulfur content to determine the sulfur oxides emission rate, the CEMS shall use the following equation to calculate the emissions of sulfur oxide:

$$e_i = s_i \times d_i \times 1.662 \times 10^{-7} \qquad \text{(Eq. 4)}$$

where:

e_i	=	The emissions of sulfur oxide (lb/hr),
s_i	=	The sulfur content of fuel gas (ppmv),
d_i	=	The fuel gas flow rate (scfh).

Example Calculation:

s_i	=	38 ppmv
d_i	=	1,576,980 scfh = 1.577 x 10^6 scfh
e_i	=	(38)(1.577 x 10^6 scfh)(1.662 x 10^{-7}) = 9.96 lb/hr.

f. All measurements for concentrations and stack gas flow rates, and selection of F factor shall be made on a consistent wet or dry basis.

g. CEMS status. The following codes shall be used to report the CEMS status:

1-1 - VALID DATA

2-2 - CALIBRATION

3-3 - OFF LINE

4-4	-	ALTERNATE DATA ACQUISITION (e.g., manual sampling)
5-5	-	OUT OF CONTROL
6-6	-	FUEL SWITCH (e.g., gas to oil, coke to coal)
7-7	-	10% RANGE (may be used to report at default 10% valid range whenever actual concentration value is below 10%)
8-8	-	LOWER THAN 10% RANGE (may be used to report at actual concentration value if less than 10% valid range
9-9	-	NON-OPERATIONAL

h. For processes in which less than 50% of emissions are caused by fuel combustion, record the Source Classification Code (SCC) for the process conducted. SCCs are listed in the State of California Air Resources Board Document "Instructions for the Emission Data System Review and Update Report, Appendix III, Source Classification Codes and EPA Emission Factors".

i. The count of valid data points collected.

j. The count of data points in excess of 95% of span range of the monitor collected.

2. Hourly Calculations

The hourly average stack gas concentrations of sulfur oxides and oxygen, the stack gas volumetric flow rate, the fuel flow rate, the fuel sulfur content of the fuel gas, and the emission rate of sulfur oxides shall be calculated for each piece of affected equipment as follows:

$$A = \frac{\sum_{i=1}^{n} a_i}{n} \quad \text{(for } SO_x \text{ concentration)} \qquad \text{(Eq. 5)}$$

$$B = \frac{\sum_{i=1}^{n} b_i}{n} \quad \text{(for } O_2 \text{ concentration)} \qquad \text{(Eq. 6)}$$

$$C = \frac{\sum_{i=1}^{n} c_i}{n} \quad \text{(for stack gas volumetric flow rate)} \qquad \text{(Eq. 7)}$$

n

$$D = \frac{\sum_{i=1} d_i}{n} \quad \text{(for fuel flow rates)} \qquad \text{(Eq. 8)}$$

Calculate D for each type of fuel firing separately.

$$S = \frac{\sum_{i=1}^{n} s_i}{n} \quad \text{(for sulfur content of fuel gas)} \qquad \text{(Eq. 9)}$$

$$E_k = \frac{\sum_{i=1}^{n} e_i}{n} \quad \text{(for } SO_x \text{ emissions)} \qquad \text{(Eq. 10)}$$

All concentrations and stack gas flow rates shall be made on a consistent wet or dry basis

where:

A = The hourly average stack gas concentration of sulfur oxides (ppmv),

a_i = The measured stack gas concentrations of sulfur oxides (ppmv),

B = The hourly average oxygen stack concentration (%),

b_i = The measured stack gas concentrations of oxygen (%),

C = The hourly average stack gas flow rate (scfh),

c_i = The measured stack gas volumetric flow rates (scfh),

D = The hourly average metered fuel flow rates, for each type of fuel (appropriate units of volumetric flow rate for each type of fuel, e.g., scfh, gal/hr, lb/hr, bbl/hr, liters/hr, etc.),

d_i = The metered fuel flow rates for each type of fuel (appropriate units of volumetric flow rate for each type of fuel, e.g., scfh, gal/hr, lb/hr, bbl/hr, etc.),

S = the hourly average sulfur content of the fuel (ppmv),

E_k = The hourly average emissions of sulfur oxide (lb/hr),

e_i = The measured emissions of sulfur oxide (lb/hr),

n = Number of valid data points during the hour.

The values of A through E_k shall be recorded for each affected piece of equipment.

Example Calculation:

For SO_x concentration:

$a_1 = 3.0$ ppm, $a_2 = 4.6$ ppm, $a_3 = 12.2$ ppm, $a_4 = 7.0$ ppm.

$$A = \frac{\sum_{i=1}^{n} a_i}{n} = \frac{3.0 + 4.6 + 12.2 + 7.0}{4} = 6.7 \text{ ppm}$$

For O_2 concentration:

$b_1, = 3.5\%\ O_2, b_2 = 5.2\%, b_3 = 4.4\%, b_4 = 3.0\%$

$$B = \frac{\sum_{i=1}^{n} b_i}{n} = \frac{3.5 + 5.2 + 4.4 + 3.0}{4} = 4.0\ \%$$

For stack gas volumetric flow rate:

$c_1 = 89{,}160$ scfh $c_3 = 91{,}980$ scfh
$c_2 = 90{,}120$ scfh $c_4 = 89{,}520$ scfh

$$C = \frac{\sum_{i=1}^{n} c_i}{n} = \frac{89{,}160+90{,}120+91{,}980+89{,}520}{4} = 90{,}195 \text{ scfh}$$

For Sulfur:

$$S = \frac{\sum_{i=1}^{n} S_i}{n} \quad \text{(for sulfur content of fuel gas)}$$

$S_1 = 558$ ppmv H_2S $S_3 = 722$ ppmv H_2S
$S_2 = 630$ ppmv H_2S $S_4 = 785$ ppmv H_2S

$$S = \frac{588 + 630 + 722 + 785}{4} = 681 \text{ ppmv } H_2S$$

For fuel flow rate:

$d_1 = 106{,}392$ scfh $d_3 = 101{,}426$ scfh
$d_2 = 96{,}504$ scfh $d_4 = 92{,}065$ scfh

$$D = \frac{\sum_{i=1}^{n} d_i}{n} = \frac{106{,}392+96{,}504+101{,}406+92{,}065}{4} = 99{,}097 \text{ scfh}$$

For SO_x emission rate:

$e_1 = .032$ lb/hr, $e_2 = .037$ lb/hr, $e_3 = .039$ lb/hr, $e_4 = .041$ lb/hr

$$E_k = \frac{\sum_{i=1}^{n} e_i}{n} = \frac{.032+.037+.039+.041}{4} = .037 \text{ lb/hr.}$$

3. Daily Calculations

a. Daily mass emissions calculation

The daily emissions of sulfur oxides shall be calculated and recorded for each affected SO_X source using the following procedure:

$$G = \sum_{k=1}^{N} E_k + \sum_{m=1}^{P} E_m \qquad \text{(Eq. 11)}$$

where:

G = The daily emissions of sulfur oxide (lb),

E_k = The hourly average emission rate using CEMS (lb/hr)

E_m = The hourly average emission rate of sulfur oxides using substitute data (see Chapter 2, Subdivision B, Paragraph 5, Subparagraph b and Chapter 2, Subdivision F)(lb/hr),

N = Number of hours of valid data (see Chapter 2, Subdivision B, Paragraph 5) from the CEMS coinciding with the source operating hours,

P = Number of hours using substitute data when the source is operating; and

M = Number of hours during the day.

Note that $M = N + P = 24$ hours

Example Calculation:		
E_m	=	1.7 lb/hr
N	=	23 hrs
P	=	1 hr
M	=	24 hr
E_k	=	0.037 lb/hr
G	=	(0.037 lb/hr)(23 hr) + (1.7 lb/hr)(1hr)
G	=	2.55 lb/day SO_X

4. Operational Requirements

The CEMS shall be operated and data recorded at all times except for CEMS breakdowns and repairs. Calibration data shall be recorded during zero and span calibration checks, and zero and span adjustments. For periods of hot standby the Facility Permit holder may enter a default value for SO_X emissions. Before using any default values the Facility Permit holder must obtain the approval of the Executive Officer and must include in the CEMS applications or CEMS plans the estimates of SO_X emissions, the SO_X concentrations, the oxygen concentrations, the sulfur content of fuel gas, and the fuel input rates or the stack gas volumetric flow rates during hot standby conditions. The Executive Officer will approve only those emission values which are found to correspond to hot standby conditions.

5. Requirements for Valid Data Points

Valid data points are data points from a CEMS which meets the requirements of Chapter 2, Subdivision B, Paragraph 14, and which is not out-of-control as defined in Attachment C - Quality Assurance and Quality Control Procedures. In addition, whenever specifically allowed by these RECLAIM rules, data points obtained by the methods specified in Chapter 2, Subdivision B, Paragraph 6 or Chapter 2, Subdivision B, Paragraph 7, are considered valid. Furthermore, a data point gathered by a certified CEMS except a zero value data point, shall not be valid unless it meets the requirements of Chapter 2, Subdivision B, Subparagraph (8)(a). A zero value data point is a data point gathered while the source is not operating and is within 5% of the span range from zero value.

a. Each CEMS and component thereof shall be capable of completing a minimum of one cycle of operation (sampling, analyzing and data recording) for each successive 15-minute interval.

b. Raw data shall be gathered from the monitors at equally spaced intervals. The Facility Permit holder shall specify, within the test report for a Relative Accuracy Test Audit of a CEMS, the frequency of data gathering in a 15-minute interval. This data gathering frequency shall remain the same throughout the period following the Relative Accuracy Test Audit until a subsequent Relative Accuracy Test Audit is conducted with a different specified frequency. The specified frequency shall be the frequency for data gathering to constitute continuous measurement.

c. All valid raw data points gathered from the monitors within a 15-minute interval shall be used to compute a 15-minute average emissions data point. If only one valid data point is gathered within a 15-minute interval, that data point shall be used as the 15-minute average emission data point. No invalid data points may be used to compute the 15-minute average emission data point. A valid 15-minute average emission data point must further be based on a minimum of one valid raw data point.

d. Except for facilities which are required to comply with 40 CFR Part 75, the following data for each 15-minute period shall be computed for each CEMS:
   i. the average emissions values,
   ii. the count of valid data points, and
   iii. the count of data points in excess of 95% of span range of the monitor.

e. All SO_x concentration, volumetric flow, and SO_x emission rate data shall be reduced to 1 hour averages. Valid hour averages shall be equally computed based on four valid 15-minute average emission data points equally spaced over each 1 hour period, commencing at 12:00 a.m., except for a maximum of four 1-hour maintenance periods in each day during which CEMS maintenance activities such as calibration, quality assurance, maintenance, or CEMS repair is conducted. During these 1-hour maintenance periods a valid hour average shall consist of at least two valid 15-minute average emission data points. A 1-hour maintenance period is defined when the operation of the CEMS is interrupted for CEMS maintenance activities at any time during any 1-hour period, and that period shall count towards the four 1-hour maintenance periods allowed regardless of the number of valid data points gathered. The CEMS shall be kept properly operational at all times unless such CEMS must be turned off for CEMS maintenance activities.

f. Failure of the CEMS to acquire the required number of valid 15-minute average emission data points within any 1-hour period shall result in the loss of such data for the entire 1-hour period and the Facility Permit holder shall record and report data by means of the data acquisition and handling system for the missing hour in accordance with the applicable procedures for substituting missing data in the Missing Data Procedures in Chapter 2 Subdivision E of this document.

6. Alternative Data Acquisition Using Reference Methods

a. When valid sulfur oxides emission data is not collected by the permanently installed CEMS, emission rate data may be obtained using District Methods 6.1 or 100.1 (for SO_X concentration in the stack gas) in conjunction with District Methods 1.1, 2.1, 3.1, and 4.1 or by using District Methods 6.1 or 100.1 in conjunction with District Method 3.1 and EPA Method 19. Emission rate data may also be obtained using District Methods 307-91 or ASTM Method D1072-90, Standard Test for Total Sulfur in Fuel Gases (for sulfur content in the fuel gas) in conjunction with the fuel gas flow rate.

b. If the Facility Permit holder chooses to use a standby CEMS (such as in a mobile van or other configuration), to obtain alternative monitoring data at such times when the permanently installed CEMS for the affected source(s) cannot produce valid data, then the standby CEMS is subject to the following requirements:

i. Standby CEMS shall be equivalent in relative accuracy, reliability, reproducibility and timeliness to the corresponding permanently installed CEMS.

ii. The Facility Permit holder shall submit a standby CEMS plan to the District for review prior to using the standby CEMS.

iii. District acceptance of standby CEMS data shall be contingent on District approval of the plan.

iv. The use of standby CEMS shall be limited to a total of 6 months for any source(s) within a calendar year.

v. The Facility Permit holder shall notify the District within 24 hours if the standby CEMS is to be used in place of the permanently installed CEMS.

vi. During the first 30 days of standby CEMS use, the Facility Permit holder shall conduct a Certified Gas Audit (CGA) of the standby CEMS.

vii. The Facility Permit holder shall notify the District within the 30-day period if the standby CEMS shall be used longer than 30 days.

viii. After the first 30 days of using the standby CEMS, the Facility Permit holder shall conduct at least one RATA of the standby CEMS and the RATA shall be conducted within 90 days of the initial use of the standby CEMS.

ix. All RATA and CGA shall be performed by testing firms/laboratories who have received approval from the District by going through the District's laboratory approval program.

x. Immediately prior to obtaining data from the source(s) to be monitored, the standby CEMS shall be quality assured in accordance with District Method 100.1

7. Alternative Data Acquisition Using Process Curves or Other Means

Process curves of SO_X emissions or other alternative means of SO_X emission data generation shall be used to obtain sulfur oxides emission data, provided the Facility Permit holder has obtained the approval of the Executive Officer prior to using alternate means of SO_X emission data generation. The process curves and the alternate means of SO_X emission data generation mentioned in this paragraph shall not be used more than 72 hours per calendar month and shall only be used if no CEMS data or reference method data gathered under Chapter 2, Subdivision B, Paragraph 6 is available. Process curves may be used on units which have air pollution control devices for the control of sulfur oxides emissions provided the Facility Permit holder submits a complete list of operating conditions that characterize the permitted operation. The conditions must be specified in the Facility Permit for that equipment. The process variables specified in the Facility Permit conditions must be monitored by the source.

8. Span Range Requirements for SO_x Analyzers or Fuel Gas Sulfur Analyzers and O_2 Analyzers

a. Full scale span ranges for the SO_x analyzers and O_2 analyzers used as part of a stack gas volumetric flow system at each source shall be set on an individual basis. The full scale span range of the SO_x analyzers and O_2 analyzers shall be set so that all data points gathered by the CEMS lie within 10 - 95 percent of the full scale span range. However, any data points that fall below 10 percent of the full scale span range may be reported in accordance with 8(b), 8(c), or 8(d) as applicable. Missing Data Procedures as prescribed in Chapter 2, Subdivision E shall be substituted for any data points falling above 95 percent range of the full scale span range.

b. For CEMS with RECLAIM certified multiple span ranges, the Facility Permit holder shall report data that falls below 10 percent of the higher full scale span range and above 95 percent of the lower full scale span range, at the 10 percent value of the higher full scale span range.

c. In the event that any data points gathered by the CEMS fall below 10 percent of the full scale span range, the Facility Permit holder may elect to report SO_x concentrations at the 10 percent full scale span range value.

d. In the event that any data points gathered by the CEMS fall below 10 percent of the lowest vendor guaranteed full scale span range for that CEMS (defined as the lowest full scale span range that the vendor guarantees to be capable of meeting all current certification requirements of RECLAIM in Rule 2011 Protocols, Appendix A), the Facility Permit holder may elect to use the following procedures to measure and report SO_x concentrations.

   i. Report all monitored concentrations that fall below 10 percent of the lowest vendor guaranteed full scale span range for that CEMS at the 10 percent lowest vendor guaranteed full scale span range value, or

   ii. Report all monitored concentrations that fall below 10 percent of the lowest vendor guaranteed full scale span range for that CEMS at the actual measured value, provided that the CEMS meets the Alternative Performance Requirements prescribed in Attachment F.

   The Alternative Performance Requirements prescribed in Attachment F shall be imposed in place of the semiannual assessments as required pursuant to Attachment C (B)(2).

e. The Facility Permit holder electing to use (B)(8)(c) and (B)(8)(d)(i) to report SO_x concentrations that fall below 10 percent of full scale span range or 10 percent of the lowest vendor guaranteed full scale span range for that CEMS, shall meet the following:

   i. In the event any of the specified testing requirements as prescribed in Attachment C (B)(2) are not met, the Facility Permit holder shall no longer use (B)(8)(c) or (B)(8)(d)(i) to report SO_x concentrations below 10 percent of the full scale span range until compliance is demonstrated. Missing Data Procedures specified in Chapter 2, Subdivision E shall apply retroactively from the date in which the Facility Permit holder last demonstrated compliance with Attachment C (B)(2).

   ii. From September 8, 1995 to the beginning of the compliance year (January 1, 1995 for Cycle 1 and July 1, 1995 for Cycle 2), the Facility Permit holder may retroactively report concentrations that fell below 10 percent of the full scale span range at the 10 percent span range value, in lieu of using the Missing Data Procedures specified in Chapter 2, Subdivision E.

f. The Facility Permit holder electing to use (B)(8)(d)(ii) to measure and report SO_x concentrations that fall below 10 percent of the lowest vendor guaranteed full scale span range for that CEMS, shall meet the following:

i. Submit an application, with the appropriate fees, supporting documentation, and if necessary test protocols to the Executive Officer or designee in order to amend their CEMS Certification Plan to include the selected criteria. The application shall be approved by the Executive Officer or designee prior to using (B)(8)(d)(ii).

ii. (B)(8)(d)(ii) may only be chosen after initial tests as prescribed in Attachment F are completed and demonstrate that the CEMS is capable of measuring SO_x concentrations at below 10 percent of the full scale span range.

iii. In the event any of the specified reporting and testing requirements for (B)(8)(d)(ii) as prescribed in Attachment F are not met, the Facility Permit holder shall no longer use (B)(8)(d)(ii) to measure SO_x concentrations below 10 percent of the lowest vendor guaranteed full scale span range for that CEMS until compliance with (B)(8)(d)(ii) is demonstrated. Missing Data Procedures described in Chapter 2, Subdivision E shall apply retroactively from the date in which the Facility Permit holder last demonstrated compliance with (B)(8)(d)(ii), unless the Facility Permit holder can demonstrate compliance with Attachment C (B)(2), then the Facility Permit holder may report concentrations retroactively at the 10 percent lowest vendor guaranteed span range value and may continue to report at the 10 percent lowest vendor guaranteed span range value until compliance is demonstrated with (B)(8)(d)(ii).

iv. In the event that the SO_x concentrations are at levels such that the Facility Permit holder cannot complete the low level spike recovery test or alternative reference method test for low level concentrations pursuant to Attachment F, then the Facility Permit holder may elect to report all monitored concentrations that fall below 10 percent of the lowest vendor guaranteed full scale span range at the 10 percent lowest vendor guaranteed full scale span range value, in lieu of using Missing Data Procedures.

v. Upon approval of the CEMS application to use (B)(8)(d)(ii), the Facility Permit holder may retroactively report concentrations at the 10 percent lowest vendor guaranteed span range value in lieu of using the Missing Data Procedures specified Chapter 2, Subdivision E, from the beginning of the compliance year for which the application was submitted up until the application approval date.

g. Up until July 1, 1996, Facility Permit holders whose CEMS have been provisionally or finally certified prior to September 8, 1995, and have used Missing Data Procedures as prescribed in Chapter 2, Subdivision E to report mass emissions that have been measured by the CEMS in the 10 percent to less than 20 percent of full scale span range, may report the actual concentrations measured in this range as valid data retroactively from the beginning of the current compliance year.

9. Calibration Drift Requirements

The CEMS design shall allow determination of calibration drift (both negative and positive) at zero level (0 to 10 percent of full scale and high-level (80 to 100 percent of full scale) values. Alternative low-level and high-level span values shall be allowed with the prior written approval of the Executive Officer.

10. Relative Accuracy Requirements for Stack Gas Volumetric Flow Measurement Systems

The stack gas volumetric flow measurement system shall meet a relative accuracy requirement of being less than or equal to 15 percent of the mean value of the reference method test data in units of standard cubic feet per hour (scfh). Relative accuracy is calculated by the equations in Section 8 of 40 CFR Part 60, Appendix B, Performance Specification 2. Alternatively, for cases where the mean stack gas velocity obtained by reference method test is less than 15 feet per second, the flow relative accuracy requirement may be met if equation 11a is satisfied.

$$|d| + |cc| <= 2 \text{ feet per second} \times A \times cf \qquad \text{(Eq. 11a)}$$

Where

d = average of differences between stack gas volumetric flow measurement system reading and the corresponding reference method test data in units of standard cubic feet per hour.

cc = confidence coefficient as determined by the equations in Section 8 of 40 CFR Part 60, Appendix B, Performance Specification 2.

A = Stack cross sectional area in the plane of measurement.

cf = conversion factor to standard cubic feet per hour.

The volumetric flow measurement system shall also meet the specifications in Attachment B (BIAS TEST) of this protocol. Prior to conducting a certification or re-certification test, the Facility Permit holder shall perform a flow profile study to determine the acceptability of the potential flow monitor location and to determine the number and location of flow sampling points required to obtain a representative flow value. The results of such study shall be part of the certification test report.

There shall be a minimum of nine sets of tests conducted. All data collected shall be submitted to the Executive Officer and shall be used to determine relative accuracy except data may be rejected per the technical guidance or for unusual problems and/or occurrences during testing (e.g., process upsets, CEMS malfunction, testing failure) if the number of tests exceeds nine sets. Any exclusion of data must be substantiated with appropriate documentation and is subject to approval by the Executive Officer.

In situations where the stack gas velocity is low (less than 10 ft./sec.) and the above relative accuracy procedure provides results that have a low level of accuracy and precision, the relative accuracy of the fuel flow meter may be determined according to one of the following alternatives:

a. Calibrate the facility CEMS fuel flow meter in accordance with the procedures outlined in 40 CFR Part 75, Appendix D, either in-line or off-line.

b. Calibrate a test fuel flow meter in accordance with the procedures outlined in 40 CFR Part 75, Appendix D. Use the calibrated test fuel meter to calibrate the facility CEMS fuel flow meter to the same level of accuracy and precision as in 40 CFR Part 75, Appendix D.

c. Calibrate a test fuel flow meter according to the procedure outlined in (B)(10)(b) and install this meter in line with the facility CEMS fuel flow meter and use 40 CFR Part 60, Method 19 (F-factor approach) to determine relative accuracy to the same level of accuracy as in (B)(10).

Other alternative techniques (e.g., tracer gas approach, electronic micro-manometer) may be used to determine relative accuracy of fuel flow meters where low stack volumetric flow rates exist, if these techniques are approved in writing by the District.

11. Quality Assurance for Fuel Flow Meters

Fuel flow measuring devices used for obtaining stack flow in conjunction with F-factors shall be tested as installed for relative accuracy using reference methods to determine stack flow.

If the flow device manufacturer has a method or device that permits the fuel flow measuring device to be tested as installed for relative accuracy, the Facility Permit holder shall request approval from the Executive Officer. Approval will be granted in cases where the Facility Permit holder can demonstrate to the satisfaction of the Executive Officer that no suitable testing location exists in the exhaust stacks or ducts and that it would be an inordinate cost burden to modify the exhaust stack configuration to provide a suitable testing location. The method or device used for relative accuracy testing shall be traceable to NIST standards. This method shall be used only if natural gas, fuel oil, or other fuels can be shown, by the Facility Permit holder to have stable F-factors and gross heating values, or if the Facility Permit holder measures the F-factor and gross heating value of the fuel. A stable F-Factor is defined as not varying by more than +/-2.5 % from the constant value used for F-Factor. For the fuels listed in 40 CFR 60, Appendix A, Method 19, Table 19-1, the F-Factors are assumed to be stable at the value cited in Table 19-1. Any F-Factor cited in Regulation XX shall supersede the F-Factor in Table 19-1. For fuels not listed in the citations above, but which the Facility Permit holder can demonstrate that the source-specific F-Factor meets the same stability criteria, periodic reporting of F-Factor may be accepted and the adequacy to the frequency of analysis shall be demonstrated by the facility such that the probability that any given analysis will differ from the previous analysis by more than 5% (relative to the previous analysis) is less than 5%. Analysis records shall be maintained, including all charts and laboratory notes.

12. Relative Accuracy Requirements for Mass Emission Rate Measurement

The mass emission rate measurement shall meet a relative accuracy requirement of being less than or equal to 20 percent of the mean value of the reference method test data in units of lb/hr. Relative accuracy is calculated by the equations in Section 8 of 40 CFR Part 60, Appendix B, Performance Specification 2. The emission rate measurement shall also meet the specifications in Attachment B (BIAS TEST) of this Appendix A. Alternatively, for cases where the mean SOx concentration obtained by reference test method is less than or equal to 10.0 ppm, or the mean stack gas velocity obtained by reference test method is less than 15 feet per second, the mass emission rate measurement relative accuracy requirement may be met if equation 11b is satisfied.

$$|d| + |cc| <= (c \times s \times A) \times cf \qquad \text{(Eq. 11b)}$$

Where

d = average of differences between mass emission rate determined by the CEMS and the corresponding reference method test data in units of pounds per hour.

cc = confidence coefficient as determined by the equations in Section 8 of 40 CFR Part 60, Appendix B, Performance Specification 2.

A = Stack cross sectional area in the plane of measurement.

c = 2.0 ppm or mean concentration obtained by reference test method, whichever is greater.

s = 2 feet per second or mean stack gas velocity obtained by reference test method, whichever is greater.

cf = conversion factor to pounds per hour.

There shall be a minimum of nine sets of tests conducted. All data collected shall be submitted to the Executive Officer and shall be used to determine relative accuracy except data may be rejected per the technical guidance or for unusual problems and/or occurrences during testing (e.g., process upsets, CEMS malfunction, testing failure) if the number of tests exceeds nine sets. Any exclusion of data must be substantiated with appropriate documentation and is subject to approval by the Executive Officer.

13. Relative Accuracy Requirements for Analyzers

The sulfur oxides gas analyzers shall meet a relative accuracy requirement of being less than or equal to 20 percent of the mean value of the reference method test data in units of ppmv for sulfur oxides. Relative accuracy is calculated by the equations in Section 8 of 40 CFR, Part 60, Appendix B, Performance Specification 2. Alternatively, for cases where the mean value of the reference method test data is less than 10 ppmv, the SOx concentration relative accuracy requirement may be met if equation 11c is satisfied.

$$|d| + |cc| <= 2.0 \text{ ppmv} \qquad \text{(Eq. 11c)}$$

Where:

d = average of differences between the SOx concentration measurement system reading and the corresponding reference method test data in units of ppmv.

cc = confidence coefficient as determined by the equations in Section 8 of 40 CFR Part 60, Appendix B, Performance Specification 2.

The oxygen and carbon dioxide gas analyzers shall meet a relative accuracy requirement of being less than or equal to 20 percent of the mean value of the reference method test data in units of volume percent. Relative accuracy is calculated by the equations in Section 8 of 40 CFR, Part 60, Appendix B, Performance Specification 2. Alternatively, for cases where the mean value of the reference method test data for oxygen or carbon dioxide concentration is less than 5.0 volume percent, the relative accuracy requirement for oxygen or carbon dioxide concentration may be met if equation 11d is satisfied.

$$|d| + |cc| <= 1.0 \text{ volume percent} \qquad \text{(Eq. 11d)}$$

Where:

d = average of differences between the oxygen or carbon dioxide concentration measurement system reading and the corresponding reference method test data.

cc = confidence coefficient as determined by the equations in Section 8 of 40 CFR Part 60, Appendix B, Performance Specification 2.

The portion of the CEMS which samples, conditions, analyzes, and records the sulfur in the fuel gas shall be certified using the specifications in 40 CFR, Part 60, Appendix B, Performance Specification 2 with the exception that District Method 307-91 shall be used for reference method to determine the sulfur content in the fuel gas. Units using monitors with more than one span range must perform the calibration error test on all span ranges. This portion of the CEMS shall also meet the specifications in Attachment B of this Appendix A.

There shall be a minimum of nine sets of tests conducted. All data collected shall be submitted to the Executive Officer and shall be used to determine relative accuracy except data may be rejected per the technical guidance or for unusual problems and/or occurrences during testing (e.g., process upsets, CEMS malfunction, testing failure) if the number of tests exceeds nine sets. Any exclusion of data must be substantiated with appropriate documentation and is subject to approval by the Executive Officer.

14. Certification

a. Provisional Approval

The Facility Permit holder of a major source shall submit certification test results and supporting documents to the District for each CEMS within the applicable time period required by Rule 2011 to install, operate, and maintain a CEMS. The Facility Permit holder shall certify that the results show that the CEMS has met all the requirements of the protocol if its submission is after August 31, 1994. Upon receipt of the test results and the certification that the CEMS is in compliance, the District will issue a Provisional Approval. The effective date of Provisional Approval shall be the last date of source testing if the test results are submitted within 60 days from the last date of source testing. However, if the test results are submitted more than 60 days after the last date of source testing, the effective date of Provisional Approval shall be the date of submittal of the testing results. After the Provisional Approval, the Facility Permit holder shall comply with the requirements under Attachment C - Quality Assurance and Quality Control Procedures.

b. Final Certification

After the Provisional Approval, all the data measured and recorded by the CEMS will be considered valid quality assured data provided that the Executive Officer does not issue a notice of disapproval of final certification. Final certification of the CEMS will be granted if the certification test results show that the CEMS has met all the requirements of the protocol, including Subdivision B, Paragraphs 10, 12, and 13 of this Chapter.

In the case where the test results show that the CEMS does not meet all the requirements of the rule, the Executive Officer will disapprove the final certification. If this occurs, the previously considered valid data from the date of Provisional Approval shall be replaced by data as specified in subdivision (E) -Missing Data Procedures. This procedure shall be used until the time that new certification test results are submitted, and the CEMS has received final approval by the District. After the Provisional Approval, the Facility Permit holder shall comply with the requirements under Attachment C - Quality Assurance and Quality Control Procedures. Data collected by the CEMS shall not be valid unless the CEMS is demonstrated to meet the requirements under Attachment C.

c. Re-certification

The Facility Permit holder shall conduct tests to re-certify a certified CEMS whenever the CEMS is modified in accordance with paragraph (B)(17).

15. Sampling Location Requirements

Each affected piece of equipment shall have sampling locations which meet the "Guidelines for Construction of Sampling and Testing Facilities" in the District Source Test Manual. If an alternate location (not conforming to the criteria of eight duct diameters downstream and two diameters upstream from a flow disturbance) is used, the absence of flow disturbance shall be demonstrated by using the District method in the Source Test Manual, Chapter X, Section 1.4 or 40 CFR, Part 60, Appendix A, Method 1. Section 2.5 and the absence of stratification shall be demonstrated using District method in the Source Test Manual, Chapter X, Section 13.

16. Sampling Line Requirement

The CEMS sample line from the CEMS probe to the sample conditioning system shall be heated to maintain the sample temperature above the dew point of the sample. This requirement does not apply to dilution probe systems where no sample condensation occurs.

17. Recertification Requirements

The District will reevaluate the monitoring systems at any affected piece of equipment where changes to the basic process equipment or air pollution control equipment occur, to determine the proper full span range of the monitors. Any monitor system requiring change to its full span range in order to meet the criteria in Chapter 2, Subdivision B shall be recertified according to all the specifications in Chapter 2, Subdivision B, Paragraphs 8, 10, 11, and 12, as applicable, including the relative accuracy tests, the calibration drift tests, and the calibration error tests. A new CEMS plan shall be submitted for each CEMS which is reevaluated.

The recertification for any reevaluated CEMS, including existing, modified or new CEMS, monitoring an existing or modified major source that was previously permitted under RECLAIM, shall be completed within 90 days of the start-up of the newly changed or modified equipment monitored by such CEMS. The Facility Permit holder shall calculate and report SO_x emission data for the period prior to the CEMS recertification by means of the automated data acquisition and handling system according to the following procedures:

a. For any CEMS which is recertified within 90 days of start-up of the newly modified equipment, the emission data recorded by the CEMS prior to the recertification would be considered valid and shall be used for calculating and reporting SO_X emissions for the equipment it serves.

b. For any CEMS which is not recertified within 90 days of start-up of the newly modified equipment, the 90th percentile emission data (lb/day) for the previous 90 unit operating days recorded by the CEMS prior to the recertification shall be used for calculating and reporting SO_X emissions for the equipment it serves.

18. Quality Assurance Procedures for Analyzers

The quality assurance and quality control requirements for analyzers, flow monitors, and SO_2 emission rate systems are given in Attachment C (QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES) of these guidelines. The quality assurance plans required by Attachment C of these protocols shall be submitted along with the CEMS certification application to the District for the approval of the Executive Officer. Source test and monitoring equipment inspection reports required by the Protocols shall be kept on-site for at least three years. The reference method tests are those methods specified in Chapter 6 (Reference Methods). Any CEMS which is deemed out-of-control by Attachment C shall be corrected, retested by the appropriate audit procedure, and restored to in-control status within 24 hours after being deemed out-of-control. If the CEMS is not in-control at the end of the 24-hour period, the CEMS data shall be gathered using the methods in Chapter 2, Subdivision B, Paragraph 6 and Chapter 2, Subdivision B, Paragraph 7. All data which is gathered in order to comply with Attachment C shall be maintained for three years and be made available to the Executive Officer upon request. Any such data which is invalidated shall be identified and reasons provided for any data invalidation. The sulfur oxides, oxygen, and fuel gas sulfur monitors shall also meet the specifications in Attachment B (BIAS TEST).

19. Calibration Gas Traceability

All calibration gases used during certification tests and quality assurance and quality control activities shall be NIST/EPA approved standard reference materials (SRM), certified reference materials (CRM), or shall be certified according to "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," September 1997, EPA 600/R-97/121 or any subsequent version published by EPA.

20. Relative Accuracy Test Audits Report Submittal

A test report shall be submitted to the District for each semi-annual or annual assessment test of a CEMS as required under Paragraph (B)(2) of Attachment C - Quality Assurance and Quality Control Procedures. Such report shall be submitted on or before the end of the quarter following the date of a required test.

21. Concentration Stratification

a. The owner or operator shall demonstrate at the time of certification and re-certification the absence of stratification for locating a facility CEMS gas sampling probe through testing performed according to the method in Chapter X, "Non-Standard Methods and Techniques", of the District Source Testing Manual. The number of tests shall be determined as follows:

i. A minimum of one test shall be conducted if the owner or operator demonstrates to the satisfaction of the Executive Officer that the equipment operates within a 20 percent load range for at least 80 percent of the time;

ii. A minimum of two tests shall be conducted if the equipment operates between 20 and 50 percent load range for at least 80 percent of the time; or,

iii. A minimum of three tests shall be conducted if the equipment operates outside of the criteria in clauses (i) and (ii) above.

The absence of stratification is considered verified if the difference between the highest measured concentration (time normalized) and the lowest measured concentration (time normalized) divided by the average measured concentration (time normalized), when expressed as a percentage, is less than or equal to 10 percent. Upon verification of the absence of stratification, the owner or operator may position the CEMS sampling probe at any point within the stack with the exception of those points that are adjacent to the stack wall. The CEMS sampling probe should be located in the stack at least one-third of the stack diameter. The RM for RATA may be conducted at a single point within the stack that is not adjacent to the stack wall and does not interfere with the sampling and the operation of the facility CEMS.

b. If testing demonstrates the presence of stratification, the owner or operator shall elect one of the following alternatives:

i. The owner or operator may use a single point sampling probe, if the stratification is greater than 10 percent but the difference between the highest measured concentration (time normalized) and the lowest measured concentration (time normalized) is less than or equal to 2.0 ppmv:

I. Then the CEMS sampling probe may be located at any point within the stack except any points that are adjacent to the stack wall or adjacent to either the highest measured concentration (time normalized) or the lowest measured concentration (time normalized), or

II. If it is not possible to avoid using a point adjacent to either the highest measured concentration (time normalized) or the lowest measured concentration (time normalized), then locate the CEMS sampling probe such that the placement minimizes the difference between the concentration; at the proposed probe location and the concentration at the point of highest measured concentration (time normalized) or the lowest measured concentration (time normalized).

ii. The owner or operator may use a single point sampling probe, if there exists a representative CEMS probe location such that all of the following criteria are met:

I. Each traverse point concentration is within 10.0% of the average of all traverse point concentrations (time normalized), or the difference between each traverse concentration and the average of all traverse point concentrations is less than or equal to 2.0 ppm, and

II. at least one traverse point concentration, not located next to the stack or duct wall, is within 10.0% of each adjacent traverse point concentration, or the difference between each traverse point concentration and the average of all traverse point concentrations is less than or equal to 2.0 ppm, whichever is greater, and,

III. if more than one traverse point meets the criteria listed in subclause (ii)(II), the CEMS probe shall be located at (or as near as practical) the traverse point with minimum adjacent traverse point concentration fluctuations as determined in section (ii)(II), above.

iii. The owner or operator may use a multipoint sampling probe and determine a representative multiple point sampling configuration as approved by the Executive Officer.

iv. The owner or operator may elect to modify the stack and/or CEMS sampling probe location and retest for the absence of stratification.

C. REPORTING PROCEDURES

1. Interim Reporting Procedures

a. From January 1, 1994 until December 31, 1994 (Cycle 1 facilities) and July 1, 1994 until June 30, 1995 (Cycle 2 facilities), the Facility Permit holder shall be allowed to use an interim procedure for data reporting and storage. The Facility Permit holder shall submit as part of the Facility Permit application, the methodology for interim data reporting and storage. The Facility Permit application shall be subject to the approval of the Executive Officer and shall, at a minimum, meet the requirements of Chapter 2, Subdivision C, Paragraph 1, Subparagraphs b, c and d.

b. All the data required in Chapter 2, Subdivision C, Paragraph 1, Subparagraphs c and d shall be made available to the Executive Officer.

c. For each affected piece of equipment the following information shall be stored on site in a format approved by the Executive Officer.

i. Calendar dates covered in the reporting period.

ii. Each daily emissions (lb/day) and each hourly emissions (lb/hour).

iii. Identification of the operating hours for which a sufficient number of valid data points has not been taken; reasons for not taking sufficient data; and a description of corrective action taken.

d. The following information for the entire facility shall be reported on a monthly basis in a format approved by the Executive officer:

i. Calendar dates covered in the reporting period.

ii. The sum of the daily emissions (lb/day) from each affected SO_X RECLAIM sources.

e. All data required by Chapter 2, Subdivision B, Paragraphs 1,2,3,4,5 and Chapter 2, Subdivision C, Paragraph 1, Subparagraphs c and d shall be recorded and/or transmitted to the District in a format approved by the Executive Officer.

2. Final Reporting Procedures

a. On and after January 1, 1995 (Cycle 1 facilities) and July 1, 1995 (Cycle 2 facilities), the RTU installed at each location shall be used to electronically report total daily mass emissions of SO_X and daily status codes to the District Central SO_X Station.

b. On and after January 1, 1995 (Cycle 1 Facilities) and July 1, 1995 (Cycle 2 Facilities), the Facility Permit holder shall submit to the Executive Officer a Monthly Emissions Report in the manner and form specified by the Executive Officer within 15 days following the end of each calendar month.

c. On and after January 1, 1995, (Cycle 1 facilities) and July 1, 1995 (Cycle 2 facilities), all or part of the interim data storage systems shall remain as continuous backup systems.

d. An alternate backup data storage system shall be implemented, upon request.

D. ALTERNATIVE PROCEDURES FOR EMISSION STACK FLOW RATE DETERMINATION

1. Multiple Sources Venting to a Common Stack

In the event that more than one source vents to a common stack, the alternative reference method for determining individual source flow rates shall use the F-factors in EPA Method 19 and the following equation:

$$c_i = [20.9/(20.9 - b_i)] \times \sum_{j=1}^{r} (F_{dij} \times d_{ij} \times V_{ij}) \qquad \text{(Eq. 12)}$$

where:

c_i	=	The stack gas volumetric flow rate (scfh),
b_i	=	The stack gas concentrations of oxygen (%),
r	=	The number of different types of fuel,
F_{dij}	=	The oxygen-based dry F factor for each type of fuel, the ratio of the gas volume of the products of combustion to the 0heat content of the fuel (scf/10^6 Btu),
d_{ij}	=	The metered fuel flow rate for each type of fuel measured every 15-minute period,
V_{ij}	=	The higher heating value of the fuel for each type of fuel

The product (d_{ij} x V_{ij}) must have units of millions of Btu per hour (10^6 Btu/hr). All concentrations and stack gas flow rates shall be calculated on a consistent wet or dry basis. The measurement of wet concentration and wet F factor shall be allowed provided that wet concentration of SO_x is measured.

Example Calculation:

Gaseous Fuel

B_i	=	4.2% O_2
F_{dij}	=	8710 dscf/10^6 Btu
d_{ij}	=	50,000 scfh
V_{ij}	=	1050 Btu/dscf
C_{ig}	=	[20.9/(20.9 - 4.2)] x [(8710/10^6)(50,000)(1050)
C_{ig}	=	570,938 dscfh

Liquid Fuel:

B_i	=	4.2% O_2
F_{ij}	=	9,190 dscf/10^6 Btu
d_{ij}	=	500 gal/hr.
V_{ij}	=	136,000 Btu/gal.
C_{il}	=	(20.9/20.9 - 4.2)(9,190/10^6)(136,000)(500) = 781,150 dscfh

Total Stack Flow Rate = $c_{ig} + c_{il}$ = 570,938 + 781,150 = 1,352,088 dscfh

This method shall be used for applicable sources before and after the interim period mentioned in Chapter 2, Subdivision C, Paragraph 1. The orifice plates used in each affected piece of equipment vented to a common stack shall meet the requirements in Chapter 2, Subdivision D, Paragraph 2.

2. Quality Assurance for Orifice Plate Measurements

Each orifice plate used to measure the fuel gas flow rate shall be checked once every 12 months using Reference Methods. If the orifice plate cannot be checked using Reference Methods, it may be checked using other methods that can show traceability to NIST Standards. If the orifice plate cannot be checked by Reference Methods or other methods that can show traceability to NIST standards, the orifice plate shall be removed from the gas supply line for an inspection once every 12 months, and the following inspection procedure shall be followed:

a. Each orifice plate shall be visually inspected for any nicks, dents, corrosion, erosion, or any other signs of damage according to the orifice plate manufacturer's specifications.

b. The diameter of each orifice shall be measured using the method recommended by the orifice plate manufacturer.

c. The flatness of the orifice plate shall be checked according to the orifice plate manufacturer's instructions. The departure from flatness of an orifice plate shall not exceed 0.010 inches per inch of dam height (D-d/2) along any diameter. Here D is the inside pipe diameter and d is the orifice diameter at its narrowest constriction.

d. The pressure gauge or other device measuring pressure drop across the orifice shall be calibrated against a manometer, and shall be replaced if it deviates more than ±2 percent across the range.

e. The surface roughness shall be measured using the method recommended by the orifice plate manufacturer. The surface roughness of an orifice plate shall not exceed 50 microinches.

f. The upstream edge of the measuring orifice shall be square and sharp so that it shall not show a beam of light when checked with an orifice gauge.

g. In centering orifice plates, the orifice shall be concentric with the inside of the meter tube or fitting. The concentricity shall be maintained within 3 percent of the inside diameter of the tube or fitting along all diameters.

h. Any other calibration tests specified by the orifice plate manufacturer shall be conducted at this time.

If an orifice plate fails to meet any of the manufacturer's specifications, it shall be replaced within two weeks.

3. **Fuel flow measuring devices used for obtaining stack flow in conjunction with F-factors shall be tested as installed for relative accuracy using reference methods to determine stack flow.**

If the flow device manufacturer has a method or device that permits the fuel flow measuring device to be tested as installed for relative accuracy, the Facility Permit holder shall request approval from the Executive Officer. Approval will be granted in cases where the Facility Permit holder can demonstrate to the satisfaction of the Executive Officer that no suitable testing location exists in the exhaust stacks or ducts and that it would be an inordinate cost burden to modify the exhaust stack configuration to provide a suitable testing location. The method or device used for relative accuracy testing shall be traceable to NIST standards. This method shall be used only if natural gas, fuel oil, or other fuels can be shown, by the Facility Permit holder to have stable F-factors and gross heating values, or if the Facility Permit holder measures the F-factor and gross heating value of the fuel. A stable F-Factor is defined as not varying by more than +/-2.5 % from the constant value used for F-Factor. For the fuels listed in 40 CFR 60, Appendix A, Method 19, Table 19-1, the F-Factors are assumed to be stable at the value cited in Table 19-1. Any F-Factor cited in Regulation XX shall supersede the F-Factor in Table 19-1. For fuels not listed in the citations above, but which the Facility Permit holder can demonstrate that the source-specific F-Factor meets the same stability criteria, periodic reporting of F-Factor may be accepted and the adequacy to the frequency of analysis shall be demonstrated by the facility such that the probability that any given analysis will differ from the previous analysis by more than 5% (relative to the previous analysis) is less than 5%. Analysis records shall be maintained, including all charts and laboratory notes.

E. MISSING DATA PROCEDURES

The following Missing Data Procedures shall be used to determine substitute data whenever a valid hour of SO_X emission data or fuel gas total sulfur content data has not been obtained or recorded.

1. Procedures for Missing SO_X Concentration Data or Fuel Gas Sulfur Content Data

For each equipment, whenever a valid hour of SO_X pollution concentration or fuel gas total sulfur content data has not been obtained or recorded, the Facility Permit holder shall provide substitute data using the procedures below. Alternatively, a facility may provide SO_X pollution concentration missing data using the procedure in 40 CFR Part 75 Subpart D if the relative accuracy of the pollutant analyzer and flow measurement system during the last CEMS certification test and/or RATA are both less than 10%.

a. The Facility Permit holder shall calculate on a daily basis the percent data availability from the SO_X pollutant concentration monitoring analyzer or the fuel gas sulfur content monitoring analyzer according to the following procedures.

i. Calculate on a daily basis a rolling percentage of the operating hours of each equipment that each concentration monitoring system was available for the period from the date the SO_x pollutant concentration monitoring analyzer was provisionally certified or 365 days prior to the current date (not counting the current day), whichever date is later, to the day previous to the current date.

ii. Record on a daily basis the percent annual concentration monitor availability using the following equation:

$$W = Y/Z \times 100\% \qquad \text{(Eq.13)}$$

where:

W = the percent annual monitor availability

Y = the total operating hours for which the monitor provided quality-assured data during the period from the date the SO_x pollutant concentration monitoring analyzer was provisionally certified or 365 days prior to the current date (not counting the current day), whichever date is later, to the day previous to the current date.

Z = the total operating hours of the affected piece of equipment during the period from the date the SO_x pollutant concentration monitoring analyzer was provisionally certified or 365 days prior to the current date (not counting the current day), whichever date is later, to the day previous to the current date.

Example Calculation:

Y = 1,680 hrs
Z = 2,160 hrs
W = Y/Z x 100%
W = (1,680/2,160) x 100%
W = 78%

b. Whenever the percent annual monitor availability is 95 percent or more, the Facility Permit holder shall calculate substitute data for each hour according to the following procedures.

i. For a missing data period less than or equal to 24 hours, substitute data shall be calculated using the 1N Procedure in Attachment A. If insufficient data is available to perform this calculation, substitute data shall be calculated pursuant to clause E(1)(b)(ii).

ii. For a missing data period greater than 24 hours, substitute data shall be calculated using the maximum hourly concentration recorded by the concentration monitor for the previous 30 days. If no emissions occurred during the previous 30 days, substitute data shall be calculated pursuant to clause E(1)(c)(i)(III).

c. i. Whenever the percent annual monitor availability is 90-percent or more but less than 95-percent, the Facility Permit holder shall calculate substitute data for each hour according to the following procedures.

I. For a missing data period of less than or equal to 3 hours, substitute data shall be calculated using the average of the recorded concentration for the hour immediately before the missing data period and the hour immediately after the missing data period. If no emissions occurred during the hour immediately before the missing data period or the hour immediately after the missing data period, substitute data shall be calculated pursuant to clause E(1)(c)(i)(II).

II. For a missing data period of more than 3 hours but less than or equal to 24 hours, substitute data shall be calculated using the maximum hourly concentration recorded by the concentration monitor for the previous 30 days. If no emissions occurred during the previous 30 days, substitute data shall be calculated pursuant to clause E(1)(c)(i)(III).

III. For a missing data period of greater than 24 hours, substitute data shall be calculated using the maximum hourly concentration recorded by the concentration monitor for the previous 365 days. If no emissions occurred during the previous 365 days, substitute data shall be calculated pursuant to clause E(1)(c)(ii).

ii. Whenever the percent annual monitor availability is less than 90 percent, substitute data shall be calculated using the highest hourly concentration recorded during the service of the monitoring system. For the purpose of this subparagraph, service of the monitoring system shall start from the initial certification date of the analyzer or the date when a decrease in the valid range of the monitoring system is approved by the Executive Officer.

d. For missing data periods where there is no prior CEMS data available or the highest CEMS data is zero:

i. for less than or equal to 24 hours, the mass emissions shall be calculated using totalized fuel usage and the starting emission factor specified in Table 2 of Rule 2002 or any alternative emission factor used in the determination of initial allocations; or

ii. For less than or equal to 24 hours and where fuel usage is not available, the mass emissions shall be calculated using the equipment maximum rated capacity, 100 percent equipment uptime, and the starting emission factor specified in Table 2 of Rule 2002; or

iii for greater than 24 hours, the mass emissions shall be calculated using the equipment maximum rated capacity, 100 percent uptime, and uncontrolled emission factors. An uncontrolled emission factor is an emission factor representative of the emissions prior to any emission control equipment from the source. An uncontrolled emission factor can be determined based on the starting emission factor used in the determination of initial allocations discounted by any control efficiency, or based on source test data. In determining a control efficiency, the facility permit holder may use source test data.

iv. Retroactively from January 1, 1995 and ending June 30, 1995, for Cycle 1 Facility Permit holders with major SO_X sources that do not have an approved RECLAIM certified CEMS, may calculate SO_X daily mass emissions in lieu of the procedures specified in the above clauses E(1)(d)(i), E(1)(d)(ii), and E(1)(d)(iii), using (1) the emission factor specified in Table 2 of Rule 2002 or any alternative factor used in the determination of initial allocations or specified in the facility permit and (2) the totalized fuel usage or process throughput.

v. Facility Permit holders with SO_x major sources which demonstrate to the satisfaction of the Executive Officer or designee that standard equipment is not available for measuring exhaust emissions for the purpose of RECLAIM CEMS certification may submit an application by December 31, 1995 to use an alternative exhaust gas and/or pollutant concentration measuring equipment. Such equipment must employ commercially available technology, and must be demonstrated to meet all the requirements of CEMS certification. Upon approval of the application, the Facility Permit holder may calculate SO_x daily mass emissions in lieu of the procedures specified in clauses E(1)(d)(i), E(1)(d)(ii), and E(1)(d)(iii), using the alternate method of (1) the emission factor specified in the facility permit and (2) the totalized fuel usage or process throughput. Such calculation of SO_x mass emissions may be done retroactively from July 1, 1995 and ending December 31, 1997 or until the CEMS is finally certified, whichever is earlier. The alternate method of calculating mass emissions shall be applied after the proposed equipment has been approved by the Executive Officer. If the CEMS is not certified by December 31, 1997, then SO_X daily mass emissions shall be calculated by the procedures specified in clauses E(1)(d)(i), E(1)(d)(ii), and E(1)(d)(iii) retroactive to July 1, 1995.

vi. If the Facility Permit holder demonstrates that standard equipment is not available but alternative equipment is commercially available as set forth in (E)(1)(d)(v) and also demonstrates to the satisfaction of the Executive Officer or designee that their CEMS cannot be certified because (1) there is an inordinate cost burden for flow monitoring as specified under (B)(11) and (2) that the Reference Methods, as specified in Rule 2011(h)(1) and Appendix A, cannot be applied because no suitable testing location exists in the exhaust stacks or ducts, then the Facility Permit holder may submit an alternative CEMS plan for certification by December 31, 1995. This plan must demonstrate that the proposed monitoring system complies with all other requirements of CEMS certification and is the most technically feasible in measurement accuracy. Until the alternative CEMS is certified or up until December 31, 1997, whichever is earlier, and retroactive to July 1, 1995, the Facility Permit holder may calculate SO_x daily mass emissions in lieu of the procedures specified in clauses E(1)(d)(i), E(1)(d)(ii), and E(1)(d)(iii), using the alternate method of (1) the emission factor specified in the facility permit and (2) the totalized fuel usage or process throughput. If the CEMS is not certified by December 31, 1997, then SO_x daily mass emissions shall be calculated by the procedures specified in clauses E(1)(d)(i), E(1)(d)(ii), and E(1)(d)(iii).

2. Procedures for Missing Stack Exhaust Gas Flow Rate Data

For each equipment, whenever a valid hour of stack exhaust gas flow rate data has not been obtained or recorded, the Facility Permit holder shall provide substitute data using the procedures below. Alternatively, a facility may provide stack exhaust gas flow rate missing data using the procedure in 40 CFR Part 75 Subpart D if the relative accuracy of the pollutant analyzer, flow measurement system, and emission rate measurement during the last CEMS certification test and/or RATA are all less than 10%.

a. The Facility Permit holder shall calculate on a daily basis the percent data availability from the flow monitoring system according to the following procedures.

i. Calculate on a daily basis a rolling percentage of the operating hours of each equipment that each flow monitoring system was available for the period from the date the SO_x pollutant concentration monitoring analyzer was provisionally certified or 365 days prior to the current date (not counting the current day), whichever date is later, to the day previous to the current date.

ii. Record on a daily basis the percent annual flow monitor availability using the following equation:

$$W = Y/Z \times 100\% \qquad \text{(Eq. 14)}$$

where:

W = the percent annual flow monitor availability

Y = the total operating hours for which the monitor provided quality-assured data during the period from the date the SO_x pollutant concentration monitoring analyzer was provisionally certified or 365 days prior to the current date (not counting the current day), whichever date is later, to the day previous to the current date.

Z = the total operating hours of the affected piece of equipment during the period from the date the SO_x pollutant concentration monitoring analyzer was provisionally certified or 365 days prior to the current date (not counting the current day), whichever date is later, to the day previous to the current date.

Example Calculation:

Y = 1,680 hrs
Z = 2,160 hrs
W = Y/Z x 100%
W = (1,680/2,160) x 100%
W = 78%

b. Whenever the percent annual flow monitor availability is 95 percent or more, the Facility Permit holder shall calculate substitute data for each hour according to the following procedures.

i. For a missing data period less than or equal to 24 hours, substitute data shall be calculated using the 1N Procedure in Attachment-A. If insufficient data is available to perform this calculation, substitute data shall be calculated pursuant to clause E(2)(b)(ii).

ii. For a missing data period greater than 24 hours, substitute data shall be calculated using the maximum hourly flow recorded by the flow monitor for the previous 30 days. If no emissions occurred during the previous 30 days, substitute data shall be calculated pursuant to clause E(2)(c)(iii).

c. Whenever the percent annual flow monitor availability is 90-percent or more but less than 95-percent, the Facility Permit holder shall calculate substitute data for each hour according to the following procedures.

i. For a missing data period of less than or equal to 3 hours, substitute data shall be calculated using the average of the recorded flow rate for the hour immediately before the missing data period and the hour immediately after the missing data period. If no emissions occurred during the hour immediately before the missing data period or the hour immediately after the missing data period, substitute data shall be calculated pursuant to clause E(2)(c)(ii).

ii. For a missing data period of more than 3 hours but less than or equal to 24 hours, substitute data shall be calculated using the maximum hourly flow rate recorded by the flow monitor for the previous 30 days. If no emissions occurred during the previous 30 days, substitute data shall be calculated pursuant to clause E(2)(c)(iii).

iii. For a missing data period of greater than 24 hours, substitute data shall be calculated using the maximum hourly flow rate recorded by the flow monitor for the previous 365 days. If no emissions occurred during the previous 365 days, substitute data shall be calculated pursuant to subparagraph E(2)(d).

d. Whenever the percent annual flow monitor availability is less than 90 percent, substitute data shall be calculated using the highest hourly flow rate recorded during the service of the monitoring system. For the purpose of this subparagraph, service of the monitoring system shall start from the initial certification date of the analyzer or the date when a decrease in the valid range of the monitoring system is approved by the Executive Officer.

3. Procedures for Missing Stack Exhaust Gas Flow Rate Data and Missing SO_x Concentration Data

For each equipment, whenever a valid hour of both stack exhaust gas flow rate data and SO_x pollution concentration data have not been obtained or recorded, the Facility Permit holder shall provide substitute data using emissions data and the procedures below.

a. The Facility Permit holder shall calculate and record on a daily basis the percent annual emission availability. The percent annual emission availability shall be equal to the lesser of the percent annual concentration monitor availability as determined in subparagraph E(1)(a) or the percent annual flow monitor availability as determined in subparagraph E(2)(a).

b. Whenever the percent annual emission availability is 95 percent or more, the Facility Permit holder shall calculate substitute data for each hour according to the following procedures.

i. For a missing data period less than or equal to 24 hours, substitute data shall be calculated using the 1N Procedure in Attachment-A. If insufficient data is available to perform this calculation, substitute data shall be calculated pursuant to clause E(3)(b)(ii).

ii. For a missing data period greater than 24 hours, substitute data shall be calculated using the maximum hourly emissions for the previous 30 days. If no emissions occurred during the previous 30 days, substitute data shall be calculated pursuant to clause E(3)(c)(iii).

c. Whenever the percent annual emission availability is 90-percent or more but less than 95-percent, the Facility Permit holder shall calculate substitute data for each hour according to the following procedures.

i. For a missing data period of less than or equal to 3 hours, substitute data shall be calculated using the average of the recorded emissions for the hour immediately before the missing data period and the hour immediately after the missing data period. If no emissions occurred during the hour immediately before the missing data period or the hour immediately after the missing data period, substitute data shall be calculated pursuant to clause E(3)(c)(ii).

ii. For a missing data period of more than 3 hours but less than or equal to 24 hours, substitute data shall be calculated using the maximum hourly emissions recorded for the previous 30 days. If no emissions occurred during the previous 30 days, substitute data shall be calculated pursuant to clause E(3)(c)(iii).

iii. For a missing data period of greater than 24 hours, substitute data shall be calculated using the maximum hourly emissions for the previous 365 days. If no emissions occurred during the previous 365 days, substitute data shall be calculated pursuant to subparagraph E(3)(d).

d. Whenever the percent annual emission availability is less than 90 percent, substitute data shall be calculated using the highest hourly emissions recorded during the service of the monitoring system. For the purpose of this subparagraph, service of the monitoring system shall start from the initial certification date of the analyzer or the date when a decrease in the valid range of the monitoring system is approved by the Executive Officer.

F. TIME-SHARING

1. Time-sharing is where an analyzer and possibly the associated sample conditioning system is used on more than one source. Timesharing is allowed for SO_X RECLAIM sources provided the CEMS can meet the following requirements in addition to the other requirements in this document for each source that is timeshared.

2. All sources shall have mutually compatible span range(s). The span range(s) must be able to meet the criteria in Chapter 2, Subdivision B. Paragraph 8.

3. Each source must have a data reading period greater than or equal to 3 times the longest response time of the system. For shared systems the response time is measured at the input or probe at each source. A

demonstration of response time for each source must be made during certification testing. Data is not to be collected following a switch of sampled sources until an amount of time equal to the response time has passed.

4. The CEMS must be able to perform and record zero and span calibrations at each source.

TABLE 2-A

MEASURED VARIABLES FOR MAJOR SO_X SOURCES

EQUIPMENT TYPE : FLUID CATALYTIC CRACKING UNITS

EQUIPMENT	MEASURED VARIABLES
FCCUs	1. Stack SO_x concentration and exhaust flow rate; 2. Status code; 3. Feed rate.
FCCUs with feed hydrodesulfurization	All variables identified for FCCUs.
FCCUs with SO_x reducing catalyst	All variables identified for FCCUs; AND 4. Type and amount of catalyst used.
FCCUs with wet flue gas desulfurization (e.g., slurry of $Ca(OH)_2/CaCO_3$ or $NaOH/Na_2CO_3$)	All variables identified for FCCUs; AND 4. Scrubber solution injection rate.
FCCUs with dry flue gas desulfurization (e.g., dried slurry of $Ca(OH)_2/CaCO_3$ or $NaOH/Na_2CO_3$)	All variables identified for FCCUs; AND 4. Scrubber solution injection rate.

TABLE 2-A (CONTINUED)

MEASURED VARIABLES FOR MAJOR SO_x SOURCES

EQUIPMENT TYPE : TAIL GAS UNITS

EQUIPMENT	MEASURED VARIABLES
Tail gas units	1. Stack SO_x concentration and exhaust flow rate; 2. Status code; 3. Production rate;
Tail gas units with amine treatment (e.g. MEA, DEA, SCOT)	All variables identified for tail gas units; AND 4. Amine solution injection rate
Tail gas units with caustic wash (e.g., MEROX w NaOH, catalyst)	All variables identified for tail gas units; AND 4. Caustic solution injection rate
Tail gas units with metal based wash (e.g., CHEMSWEET with ZnO and Zn Acetate, IRON SPONGE with wood chips w iron oxide)	All variables identified for tail gas units; AND 4. Metal based solution injection rate
Tail gas units with carbonate wash (e.g., CATACARB with K_2CO_3, catalyst, and inhibitor)	All variables identified for tail gas units; AND 4. Carbonate solution injection rate
Tail gas units with REDOX processes (e.g., STRETFORD with Vanadium based solution, WELLMAN-LORD SULFEROX with iron w/chelating agent)	All variables identified for tail gas units; AND 4. REDOX solution injection rate
Tail gas units with other catalytic conversion processes to H_2S (e.g., Hydrotreating)	All variables identified for tail gas units

TABLE 2-A (CONTINUED)

MEASURED VARIABLES FOR MAJOR SO_x SOURCES

EQUIPMENT TYPE : SULFURIC ACID PRODUCTION PLANTS

EQUIPMENT	MEASURED VARIABLES
Sulfuric acid production plants with dual absorption processes	1. Stack SO_x concentration and exhaust flow rate; 2. Status code; 3. Sulfuric acid production rate; 4. Strength of acid produced; 5. Inlet SO_2, O_2 concentrations to 1st and 2nd stage converters; 6. Inlet SO_3 to absorption tower; 7. Conversion efficiency of 1st and 2nd stage converters; 8. Conversion efficiency of absorption tower; 9. Efficiency of acid mist control devices; 10. Type and amount of fuel usage for furnace.
Sulfuric acid production plants with sodium sulfite/bisulfite/ammonia scrubbing processes	1. Stack SO_x concentration and exhaust flow rate; 2. Status code; 3. Sulfuric acid production rate; 4. Strength of acid produced 5. Sodium sulfite/bisulfite/ammonia injection rate; 6. Scrubber solution pH 7. Conversion efficiency of absorption tower 8. Efficiency of acid mist control devices; 9. Type and amount of fuel usage for furnace.

TABLE 2-A (CONTINUED)

MEASURED VARIABLES FOR MAJOR SO_x SOURCES

EQUIPMENT TYPE : EQUIPMENT BURNING REFINERY, LANDFILL OR DIGESTER GASEOUS FUELS

EQUIPMENT	MEASURED VARIABLES
Combustion equipment	1 Stack SO_x, O_2 concentrations, and fuel flow rate; OR Fuel sulfur content and fuel flow rate; 2. Status code;
Combustion equipment with wet scrubber (e.g., Lime CaO, Limestone $CaCO_3$, Sodium Sulfite Na_2SO_3, Double alkali $Na_2SO_3/CaO/CaCO_3$, Magnesium oxide $Mg(OH)_2$)	All variables identified for combustion equipment; AND 3. Scrubber solution injection rate.
Combustion equipment with spray dryer or dry scrubber (e.g., absorption with Na_2CO_3 or slaked lime solution)	All variables identified for combustion equipment; AND 3. Scrubber solution injection rate;
Combustion equipment with carbon adsorption	All variables identified for combustion equipment.

TABLE 2-B

REPORTED VARIABLES FOR ALL MAJOR SO_x SOURCES

EQUIPMENT	REPORTED VARIABLES
Fluid Catalytic Cracking Units Tail Gas Units Sulfuric Acid Production Equipment that burns refinery, landfill or sewage digester gaseous fuel except gas flares. Any existing equipment using SO_x CEMS or equivalent monitoring device, or that is required to install such monitoring device under District rules to be implemented as of [date of adoption]. Any SO_x source or process unit elected by the Facility Permit holder or required by the Executive Officer to be monitored with CEMS or equivalent monitoring device. Any SO_x source or process unit whose reported SO_x emissions was equal to or greater than 10 tpy for any calendar year from 1987 to 1991, inclusive, excluding any SO_X source or process unit which has reduced SO_X emissions below 10 tons per year prior to January 1, 1994.	1. Total Daily SO_x mass emissions from each source; 2. Daily status codes

3/17/17

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

RULE 2011 PROTOCOL- CHAPTER 3

PROCESS UNITS - PERIODIC REPORTING AND RULE 219 EQUIPMENT

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CHAPTER 3 - PROCESS UNITS - PERIODIC REPORTING

Process units may share fuel meters if each equipment has the same emission factor. This chapter also includes the equations describing the methods used to calculate SO_x process unit emissions and the reporting procedures. The interim reporting period does not apply to process units since existing fuel metering equipment or timers shall be used starting January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

A. GENERAL REQUIREMENTS

1. The equipment-specific or category-specific starting emission factor found in Table 2 of Rule 2002 - Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx) shall be used for quantifying quarterly mass emissions for a SOx process unit.

2. Instead of using the equipment-specific or category-specific starting emission factor found in Table 2 of Rule 2002, the Facility Permit holder of a process unit may apply to the Executive Officer to use a representative emission factor or alternative emission factor for purposes of calculating SO_x emissions. The alternative emission factor shall be established by the requirements provided in Chapter 6, Subdivision E.

3. The Facility Permit holder of a process unit shall use an emission factor or alternative emission factor to calculate the mass emission according to the methodology specified in Chapter 3, Subdivision B, Paragraph 2. (fuel totalizing meters) or Chapter 3, Subdivision B, Paragraph 3, Subparagraph a (timers).

4. The Facility Permit holder of each SO_x process unit shall use a totalizing fuel meter or timer as applicable and specified in the Facility Permit for each affected equipment to measure and report the variables listed in Tables 3-A and 3-B, respectively, for each equipment.

5. The Facility Permit holder of each SO_x process unit shall monitor, report and maintain the following records on a quarterly basis:

    a. Type and quantity of fuel burned in units of million standard cubic feet per quarter (mmscf per quarter) for gaseous fuels or thousand gallons per quarter (mgal per quarter) for liquid fuels, expressed with three significant figures minimum; or

    b. Total hours of operation.

6. The Facility Permit holder of each SO_x process unit shall also provide any other data necessary for calculating the emission rates of oxides of sulfur as determined by the Executive Officer.

7. Fuel meters and/or timers must be non-resettable and tamper-proof. They shall have seals installed by the meter/timer manufacturer to prove the integrity of the measuring device.

    Meters which are unsealed for maintenance or repairs shall be resealed by an authorized manufacturers representative.

B. EMISSION CALCULATIONS FOR REPORTED DATA

1. Quarterly Mass Emissions for Interim Periods (January 1, 1994 thru December 31, 1994 for Cycle 1 facilities; and July 1, 1994 thru June 30, 1995 for Cycle 2 facilities)

a. Pursuant to Rules 2011(d)(3) and 2011(f)(2), starting January 1, 1994 for Cycle 1 facilities, and starting July 1, 1994 for Cycle 2 facilities, the quarterly emission of each process unit shall be calculated and recorded according to:

$$E_{ip} = \sum_{j=1}^{r} d_j \times EF_{sj} \qquad \text{(Eq.15)}$$

where:

E_{ip} = The quarterly mass emission of sulfur oxides for interim period (lb/quarter).

d_j = The quarterly fuel usage for each type of fuel recorded as mmscf/quarter or mgal/quarter.

EF_{sj} = The starting emission factor used to calculate unit emissions in the initial allocation, as specified in Table 2 of Rule 2002 - Allocations for Oxides of Nitrogen (NO_x) and Oxides of Sulfur (SO_x) (lb/mmscf or lb/mgal,).

r = The number of different types of fuel.

Example calculation: IC engine burning natural gas
Starting Emission factor = 0.60 lb/mmscf Quarterly fuel usage = 2 mmscf/quarter
E_{ip} = (0.60) x (2.0) = 1.2 lb/quarter

2. Totalizing Fuel Meter Based Calculations

The Facility Permit holder of each equipment in a SO_x process unit when equipped with a totalizing fuel meter shall use emission factor listed in Table 2 of Rule 2002 or alternative emission factors established according to the methodology provided in Chapter 4 to obtain the quarterly mass emissions according to:

$$E_{EF} = \sum_{k=1}^{n} d_k \times EF_k \qquad \text{Eq.15)}$$

where:

E_{EF} = The quarterly emissions of SO_x obtained using emission factor (lb/quarter.)

d_k = The quarterly fuel usage for each type of fuel (mmscf/quarter or mgal/quarter.)

EF_k = The emission factor as specified in Table 2 of Rule 2002 - Allocations for Oxides of Nitrogen (NO_x) and Oxides of Sulfur (SO_x) (lb/mmscf, lb/mgal or lb/mbbl) or an alternative emission factor proposed by the Facility Permit holder as established from the source test requirement provided in Chapter 4

k = Each type of gaseous or liquid fuel consumed by each process unit throughout the quarter.

n = The total number of different types of fuel consumed by each process unit throughout the quarter

3. Timer-Based Emission Calculations

If the SOx process unit is equipped with a timer, the Facility Permit holder shall quantify the quarterly fuel usage for each affected equipment according to Eq. 17 - Eq. 20 and calculate the quarterly mass emissions according to Eq. 16 - Eq. 20.

a. Quarterly Fuel Usage for Each Affected SO_x Process Unit

If the SO_x process unit does not measure fuel usage with a fuel meter, the quarterly fuel usage for each affected equipment in a process unit shall be quantified according to:

$$d = d_{pu} \times (H/H_{pu}) \qquad \text{(Eq.17)}$$

Where:

d = The quarterly fuel usage of an affected SO_x process unit without a dedicated fuel meter (mmscf/quarter or mgal/quarter).

d_{pu} = The quarterly fuel usage of all SO_x process units at the facility (mmscf/quarter or mgal/quarter).

H = The quarterly heat input of an affected SO_x process unit without a dedicated fuel meter (mmBtu/quarter).

H_{pu} = The quarterly heat input of all SO_x process units at the facility (mmBtu/quarter).

Example Calculation:

d_{pu} = 1,587 mmscf/quarter

H = 5,400 mmBtu/quarter

H_{pu} = 27,000 mmBtu/quarter

$d = d_{pu} \times (H/H_{pu})$

d= 1,587 mmscf/quarter x (5,400 mmBtu/quarter – 27,000 mmBtu/quarter

d= 317.4 mmscf/quarter

The quarterly fuel usage for all SO_x process units at the facility (d_{pu}) shall be calculated according to the following equation:

$$d_{pu} = d_{fac} - d_{major} \qquad \text{(Eq.18)}$$

where:

d_{fac} = The quarterly fuel usage of all major sources and SO_x process units at the facility (mmscf/quarter or mgal/quarter).

d_{major} = The quarterly fuel usage of all major SO_x sources at the facility (mmscf/quarter or mgal/quarter).

Example Calculation:

d_{fac} = 58 mmscf/quarter
d_{major} = 42 mmscf/quarter
$d_{pu} = F_{fac} - F_{major}$
d_{pu} = 58 - 42
d_{pu} = 16 mmscf/quarter

The quarterly heat input of all SO_x process units at the facility (H_{pu}) shall be calculated according to:

$$H_{pu} = \sum_{i=1}^{n}(R_i \times T_i) \qquad \text{(Eq.19)}$$

where:

R_i = The maximum rated heat input capacity of a SO_x process unit (mmBtu/hr).

T_i = The quarterly accumulated operation hours for a SO_x process unit (hr/quarter).

i = Each process unit

n = The total number of SO_x process units at the facility.

Example Calculation:

R_1 = 3.5 mmBtu/hr
R_2 = 2.7 mmBtu/hr
T_1 = 480 hr/quarter
T_2 = 120 hr/quarter

$$H_{pu} = \sum_{i=1}^{2} (R_i \times T_i)$$

H_{pu} = (3.5 x 480) + (2.7 x 120)
H_{pu} = 2004 mmBtu/quarter

The maximum rated heat input capacity of all SO_x process units shall be in units of mmBtu/hr. Since internal combustion engines are usually rated in units of brake horse power, the maximum rated heat input capacity of an engine shall be computed as follows.

$$R = 0.002545 \times bhp / eff \quad \text{(Eq.20)}$$

where:

R = The maximum rated heat input capacity

eff = The manufacturer's rated efficiency @LHV x (LHV/HHV)

= 0.25, if not provided by the operator

bhp = The manufacturer's rated shaft output in brake horse power

Example Calculation:

eff = 0.25
bhp = 75 bhp
R = 0.002545 x bhp / eff
R = 0.002545 x 75/.25
R = 0.7635 mmBtu/hr

If gas turbines are rated in kilowatts, the rating shall be converted to mmBtu/hr by applying the manufacturer's heat rate (in mmBtu/kw-hr). If the manufacturer's heat rate is not available, a default value of 15,000 Btu/kw-hr shall be used.

Example Calculation:

Quarterly fuel usage for an ICE with maximum rated bhp of 90 bhp, 0.25 eff and a boiler rated at 4 mmBtu/hr being served by one fuel totalizer reading 10.5 mmscf. The boiler and ICE burn landfill gas.

I.C.E.= 90 bhp Boiler= 4 mmBtu/hr C_g = 80 ppmv for landfill gas
Fuel meter reading = F_{pu} = 10.5 mmscf

I.C.E.

$R = 0.002545 \times 90/.25 = 0.916$ mmBtu/hr
t = 3 hr/day x 7 days/wk. x 4 wk./mo. x 3 mo/qtr = 252 hr/qtr
$H_{ice} = R \times t = 0.916 \times 252 = 230.8$ mmBtu/qtr

Boiler

H_{boiler} = 4 mmBtu/hr x 24 hr./day x 7 day/wk. x 4 wk./mo. x 3 mo/qtr
H_{boiler} = 8064 mmBtu/qtr.
H_{pu} = 230.8 + 8064 = 8294.8 mmBtu/qtr.

$d_{ice} = d_{pu} \times (H_{ice}/H_{pu})$
= 10.5 mmscf/qtr. x (230.8/8294.8)
= .292 mmscf/qtr.

$d_{boiler} = d_{pu} \times (H_{boiler}/H_{pu})$
= 10.5 mmscf/qtr. x (8064/8294.8)
= 10.2 mmscf/qtr.

$E_{ice} = d_{ice} \times C_g \times 0.166$
E_{ice} = .292 mmscf/qtr x 80 ppmv x 0.166
E_{ice} = 3.88 lb/qtr.

$E_{boiler} = d_{boiler} \times C_g \times 0.166$
E_{boiler} = 10.2 mmscf/qtr x 80 ppmv x 0.166
E_{boiler} = 135 lb/qtr.

$E = E_{ice} + E_{boiler}$ = 3.88 + 135 = 138.88 lb/qtr.

C. TOTAL QUARTERLY EMISSIONS CALCULATION FOR ALL SO_x PROCESS UNITS AT THE FACILITY

Quarterly SO_x emissions of all SO_x process units at the facility shall be quantified according to:

$$E = \sum_{i=1}^{m} E_{EF} \qquad \text{(Eq.21)}$$

where:

E = The quarterly total emissions of SO_x for all SO_x process units (lb/quarter).

E_{EF} = The quarterly emissions of SO_x obtained using emission factor (lb/quarter).

i = Each process unit

m = The number of process units at the facility.

D. REPORTING PROCEDURES

1. The Facility Permit holder of any SO_x process unit that opts to monitor at the major source monitoring level shall meet the requirements set forth in Chapter 2 - "Major Sources - Continuous Emission Monitoring System."

2. The total recorded quarterly fuel usage data and SO_x emissions in pounds per quarter for all SO_x process units in any facility without RTU shall be recorded in a format approved by the Executive Officer and shall be submitted to the District as part of the Quarterly Certification of Emissions required by Rule 2004.

3. The Facility Permit holder of each SO_x process unit shall maintain daily records of hours of operation or quarterly usage for each SO_x process unit.

4. Any changes made in type of fuel used shall be recorded by the Facility Permit holder.

E. FUEL METER SHARING

1. A single totaling fuel meter shall be allowed to measure and record the fuel usage of more than one equipment in a process unit, provided that each piece of equipment elects for the same emission factor or alternative emission factor as specified in the Facility Permit.

2. Fuel meter sharing for the interim period shall be for those equipment in a process unit with the same emission factor.

F. RULE 219 EQUIPMENT

1. Emission Determination and Reporting Requirements

a. The Facility Permit holder shall determine the emissions for one or more equipment exempt under Rule 219 and report the emissions on a quarterly basis as part of the Quarterly Certified Emissions report required by Rule 2004. The Facility Permit holder shall be allowed to use the existing fuel totalizer, the monthly fuel billing statement, or any other equivalent methodology to quantify their fuel usage for a quarterly period.

b. Quarterly reporting period shall start on January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

c. The Facility Permit holder of each equipment shall maintain the quarterly fuel usage data for all equipment exempt under Rule 219 for three years. Such data shall be made available to District staff upon request.

d. The fuel usage for equipment exempt under Rule 219 may be used in conjunction with process units provided that they have the same emission factor.

2. Emission Calculations

The Facility Permit holder shall determine SO_x emissions for equipment exempt under Rule 219 as follows:

$$E_{EF} = \sum_{k=1}^{n} d_k \times EF_k \qquad \text{(Eq.22)}$$

where:

E_{EF} = The quarterly emissions of SO_x obtained using emission factor (lb /quarter).

d_k = The quarterly fuel usage for each type of fuel (mmscf/quarter or mgal/quarter).

EF_k = The emission factor as specified in Table 2 of Rule 2002 - Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx) (lb/mmscf, or lb/mgal or lb/mbbl or an alternative emission factor proposed by the Facility Permit holder as established from the source test requirement provided in chapter 4.

k = Each type of gaseous or liquid fuel consumed by each process unit throughout the quarter.

n = The total number of different types of fuel consumed by each process unit throughout the quarter.

3. Missing Data Periods

The Facility Permit holder shall determine SOx emissions for equipment exempt under Rule 219 using the substitute data procedures specified in Subdivision G of this Chapter for any quarter for which the Facility Permit holder did not obtain and record valid fuel consumption data as required by Subdivision F Paragraphs 1 and 2 of this Chapter.

G. SUBSTITUTE DATA PROCEDURES

1. For each process unit or process units using a common fuel meter, elapsed time meter, or equivalent monitoring device, the Facility Permit holder shall provide substitute data as described below whenever a valid quarter of usage data has not been obtained and recorded. Alternative data, based on a back-up fuel meter, elapsed time meter, or equivalent monitoring device, is acceptable for substitution if the Facility Permit holder can demonstrate to the Executive Officer that the alternative system is fully operational during meter down time and within + or - 2% accuracy. The substitute data procedures are retroactively applicable from the adoption date of the RECLAIM program.

2. Whenever data from the process monitor is not available or not recorded for the affected equipment or when the equipment is not operated within the parameter range specified in the Facility Permit, the Facility Permit holder shall calculate substitute data for each quarter, when valid data has not been obtained, according to the following procedures.

   a. For a missing data period less than or equal to one quarter, substitute data shall be calculated using the process unit(s) average quarterly fuel usage for the previous four quarters. If four quarters of data are not available, substitute data shall be calculated as if the facility has no records.

   b. For a missing data period greater than one quarter, substitute data shall be calculated using the process unit(s) highest quarterly fuel usage data for the previous four quarters. If four quarters of data are not available, substitute data shall be calculated as if the facility has no records.

   c. If the facility has no records, substitute data shall be calculated using 100% uptime during the substitution period and the process unit(s) maximum rated capacity and uncontrolled emission factor for each quarter of missing data.

TABLE 3-A

MEASURED VARIABLES FOR ALL SO_x PROCESS UNITS

EQUIPMENT	MEASURED VARIABLES
Any SO_x unit that is not categorized as a major source	1. Fuel usage; or Operating time; 2. Production rate; 3. Fuel sulfur content.

TABLE 3-B

REPORTED VARIABLES FOR ALL SO_x PROCESS UNITS

EQUIPMENT	REPORTED VARIABLES
Any SO_x unit that is not categorized as a major source	Quarterly SO_x emissions from each unit.

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CHAPTER 4

PROCESS UNITS - SOURCE TESTING

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CHAPTER 4 - PROCESS UNITS - SOURCE TESTING

This chapter contains the test methods, procedures and source testing methodology necessary for a Facility Permit holder to establish an equipment or category specific emission rate for a SO_X process unit.

All required source tests for RECLAIM super compliant major SOx sources and process units shall be performed by testing firms/laboratories who have received approval under the District's Laboratory Approval Program.

A. Test Methods

The Facility Permit holder of all RECLAIM SOx sources, when required, shall source test each equipment using the following test methods and procedures referenced in the District Source Test Manual and 40 CFR Part 60, Appendix A:

1. Determinations and measurements prior to sampling:

a. Method 1.1 - sample points, stacks greater than 12 in. in diameter

b. Method 1.2 - sample points, stacks less than 12 in. in diameter

c. Method 2.1 - flow rate, stacks greater than 12 in. in diameter

d. Method 2.2 - flow rate, direct measurement

e. Method 2.3 - flow rate, stacks less than 12 in. in diameter

f. Method 4.1 - moisture

g. EPA Method 19 - calculated flow

2. Sulfur oxides concentration:

a. Method 100.1 - sulfur oxides, sulfur dioxide, carbon monoxide, carbon dioxide, and oxygen

b. Method 6.1 - for sulfur oxides in stack gas without ammonia present.

c. District Method 6.1 or Method 100.1 shall be used to determine SO_2 stack gas concentrations, if ammonia is not present in the stack gas. If ammonia is present in the stack gas, EPA Method 6 shall be used with the following modifications :

The sampling system shall be all borosilicate or quartz glass for any surface in contact with the sample gas up to the silica gel. No flexible tubing may be used between the probe and impingers or between impingers.

An in-stack filter holder, constructed of borosilicate glass or quartz glass, shall be used in place of a glass wool plug. The filter holder must provide a positive seal against leakage from the outside or around the filter. A high-efficiency glass fiber filter shall be used. The borosilicate or quartz glass probe shall be heated and its temperature maintained at greater than 225 ^{o}F.

Smith-Greenburg impingers shall be used instead of the midget impingers. The isopropanol impinger shall not be used. The first and second impingers shall contain 100 milliliters of 3% hydrogen peroxide, the third impinger shall be blank, and the fourth impinger shall contain silica gel.

The probe shall be washed separately with 3% hydrogen peroxide and analyzed separately from the impingers. The results of the two analyses shall be summed to provide a total SO_2 catch.

All samples shall be treated with an ion exchange resin for NH_3 interference. The ion exchange resin shall be Rexyn-R or equivalent.

d. Method 307.91 - for total sulfur compounds in fuel gas

3. **Oxygen concentration:**

a. Method 3.1 - molecular weight and excess air correction factor.

b. Method 100.1 - sulfur oxides, sulfur dioxide, carbon monoxide, carbon dioxide and oxygen

B. Summary of Testing Requirements

The Facility Permit holder is required to source test all Super Compliant major SOx sources which opt to use an equipment specific emission rate or concentration limit and SO_X process units which opt for an category or equipment specific emission rate as follows:

1. Super Compliant Major SOx Sources

Once a super compliant major SOx source has been approved, the Facility Permit holder shall:

A. source test the equipment once every four calendar quarters if using an equipment specific emission rate.

B. source test the equipment once every two calendar quarters if using an equipment specific concentration limit. The test shall include a single 60 minute SOx concentration test and a relative accuracy audit of the fuel measuring device. If after two years all tests show compliance, then the testing frequency can be reduced to once per year.

2. SOx Process Units

Emission factors are assigned to process units when the Facility Permit is issued. No source testing is required for a process unit, unless the Facility permit holder opts for an equipment or category specific emission rate. The Facility Permit holder is required to determine an equipment or category specific emission rate pursuant to subdivision (D).

C. Testing frequency

The Facility Permit holders of major SO_X sources shall source test as part of their quality assurance program. Process units shall be source tested every time the Facility Permit holder applies for an equipment or category specific emission rate.

D. Guidelines for Testing to Establish an Equipment or Category Specific Emission Rate

1. For process units, the Facility Permit holder has the option of calculating and reporting emissions based on an equipment-specific or category-specific emission rate, which is based on the average fuel sulfur content that is determined from a source test. The equipment-specific or category-specific emission rate shall be used to determine compliance with the facility's allocations.

2. In order to establish an equipment specific emission rate for a process unit without post-combustion control equipment, the fuel sulfur content shall be measured once per week over a quarterly period. This quarterly measurement shall be required whenever an alternative emission factor is established. If the process unit burns the fuel of which the sulfur content is treated prior to the combustion, the sulfur content shall be source tested at the downstream of the sulfur treatment system. The measured data set must pass the confidence interval test described in Chapter 4, Subdivision D, Paragraph 6 to be considered valid. The average sulfur content shall be converted into an equipment specific

emission rate using equations provided in Chapter 4, Subdivision D, Paragraph 4.

3. In order to establish an equipment specific emission rate for a process until with post-combustion control equipment, the exhaust SO_X concentration shall be source tested at the downstream of the control equipment at four different representative operating conditions of the proposed process unit. Such testing shall be done at least three times at each condition, but not consecutively. The measured data set must pass the confidence interval test described in Chapter 4, Subdivision D, Paragraph 6 to be considered valid. The average stack concentration shall be converted to an equipment specific emission rate using the equations provided in Chapter 4, Subdivision D, Paragraph 5.

4. For process units without post-combustion equipment, an average fuel sulfur content that satisfies the confidence interval test described in Chapter 4, Subdivision D, Paragraph 6, shall be converted into an equipment specific emission rate by the following equation:

For gaseous fuels,

$$EF_k = C_{kg} \times 0.166 \qquad \text{(Eq.23)}$$

or

$$EF_k = C_{kl} \times 2.86 \qquad \text{(Eq.24)}$$

For liquid fuels,

$$EF_k = C_{kl} \times S_l \times 166 \qquad \text{(Eq.25)}$$

where:

EF_k = The equipment specific emission rate for gaseous or liquid fuel (lb/mmscf or lb/mgal).

C_{kg} = The average fuel sulfur content of gaseous fuel determined form Eq. 28 in Chapter 4, Subdivision D, Paragraph 6 (ppmv).

C_{ka} = The average fuel sulfur content of gaseous fuel determined form Eq. 28 in Chapter 4, Subdivision D, Paragraph 6 (grain/100ft^3).

C_{kl} = The average fuel sulfur content for gaseous fuel determined from Eq. 28 in Chapter 4, Subdivision D, Paragraph 6 (percent by weight).

s_l = The specific gravity of liquid fuel.

k = The different type of fuel.

Example Calculations:

(a) Equipment Specific Emission rate for process unit without post-combustion control equipment,

A 5 mmbtu/hr boiler burns natural gas. The average sulfur content of the gaseous fuel is 30 ppmv.

$$EF_k = C_{kg} \times 0.166$$
$$EF_k = (30)(0.166)$$
$$= 4.98 \text{ lb/mmscf of } SO_x \text{ emission factor}$$

(b) Equipment Specific Emission rate for process unit without post-combustion control equipment, but with pre-combustion sulfur treatment system

A 500 bhp ICE burns Diesel Oil. The specific gravity of the liquid fuel is 0.82. The average sulfur content determined after confidence interval test came out to be 0.05% by weight, which is the treated sulfur content.

$$EF_k = C_{kl} \times S_l \times 166$$
$$= (.05)(.82)(166)$$
$$= 6.806 \text{ lb/mgal of } SO_x \text{ emission factor}$$

5. For process unit with control equipment, the exhaust SO_x concentration and exhaust oxygen or stack exhaust flow rate shall be source tested at downstream of the control equipment and shall be converted to an equipment emission rate by one of the following equation:

when the exhaust oxygen is source tested,

$$EF_{k\,i} = PPMV_i \times (20.9/20.9\text{-}b) \times 1.662 \times 10^{-13} \times F_d \times V \qquad \text{(Eq.26)}$$

when the stack exhaust flow rate is source tested,

$$EF_{ki} = PPMV_i \times (C/d) \times 1.662 \times 10^{-7} \qquad \text{(Eq.27)}$$

where:

EF_{ki}	=	The equipment specific emission rate as specified in the Facility Permit (lb/mmscf for gaseous fuel or lb/mgal of liquid fuel)
k	=	Each type of fuel.
i	=	Each data source tested at each operating condition.
PPMV	=	The stack concentration of SO_x (ppmv).
b	=	The exhaust oxygen concentration determined from the source test (%).
F_d	=	The oxygen-based dry F factor for each type of fuel, the ratio of the dry gas volume of the products of combustion to the heat content of the fuel (dscf/10^6 Btu).
V	=	The higher heating value of the fuel for each type of

fuel.

C = The exhaust flow rate of the stack determined from the source test (dscf per unit time).

d = The fuel flow rate (mmscf per unit time for gaseous fuels, mgal per unit time for liquid fuels).

The exhaust flow rate shall be determined in consistent unit with fuel flow rate. For example, if C is measured as dscf per hour, d shall be measured as mmscf per hour or mgal per hour.

6. The criterion for acceptability of the average fuel sulfur content shall be a 95% confidence interval that the tested fuel sulfur contents shall be within 20% of the average fuel sulfur content. The average fuel sulfur content over a quarterly period shall be determined according to:

$$C_c = (1/n) \sum_{i=1}^{n} C_i \qquad \text{(Eq.28)}$$

$$S_c = [\sum_{i=1}^{n} (C_i - C_c)^2 / (n-1)]^{1/2} \qquad \text{(Eq.29)}$$

$$CC = t_{0.975}\, S_c/(n)^{1/2} \qquad \text{(Eq.30)}$$

$$C.I.\,(\%) = \frac{|CC|}{C_c} \qquad \text{(Eq.31)}$$

where:

S_c = The standard deviation (wt. %, grain/100 ft^3, or ppmv).

i = Each weekly testing

n = The number of quarterly testing data points, measured once a week, to determine the average sulfur content throughout the quarterly period.

Ci = The sulfur content (% wt., grain/100 ft3, or ppmv) determined at each weekly testing sampled on a random basis.

CC = The confidence coefficient

t0.975 = The t value determined from Table 4-A

Cc = The average sulfur content (%wt., grain/100 ft3, or ppmv) determined over a quarterly period.

C.I = The confidence interval with 95 % confidence level (%)

7. Category Specific Emission Rate for Process Units

a. For process units without post-combustion equipment, once an equipment specific emission rate has been established for a fuel source, such emission factor may be used as a category specific emission rate for a group of process units which all use the same fuel source.

b. For process units with post-combustion equipment, the Facility Permit holder has, in lieu of an equipment specific emission rate, the option to establish, in the Facility Permit, a category specific emission rate.

i A category specific emission rate is an average of equipment specific emission rates of a group of three or more process units which:

I. are the same type of equipment, i.e. equipment within a narrow range of rating, same manufacturer, family of model, and emission characteristics;

II. perform the same functions or processes;

III. meet the statistical limits of Subclause (D)(7)(b)(ii)(II); and

IV. are all located at a single RECLAIM facility.

A category specific emission rate must be approved by the Executive Officer and listed in the Facility Permit before it may be used to determine compliance with the facility's annual emission cap.

ii The category specific emission rate is determined by the following:

I. A minimum of three devices of the category must be tested, and equipment specific emission rates established for each of the three devices each meeting the statistical test methods for equipment specific emission rate in Paragraph (D)(6).

II. The three equipment specific emission rates will then be averaged to determine the category specific emission rate. The aggregate 36 tests of the three devices must pass a statistical "f-test" at a 95%

confidence level for the category specific emission rate to be considered valid.

III. Once the category specific emission rate has been established, approved as valid, and listed on the facility permit it can then be used to report emissions from the subject devices.

IV. To add one or more devices to this category specific emission rate, the new devices must meet the criteria in Clause (D)(7)(b)(i) and the facility must source test the new devices for one 30 minute run at each of the four loads the category specific emission rate was established. The results shall then be subjected, with the previous 36 tests, to the statistical "f" test and must meet at a 95% confidence level to be considered valid and the category specific emission rate applicable to the new devices.

Table 4-A - Table of the Factor $t_{0.975,n-1}$ for Obtaining One-Tailed Confidence Interval for the Mean

n*	$t_{0.975}$	n*	$t_{0.975}$	n*	$t_{0.975}$
6	2.571	10	2.262	13	2.179
7	2.447	11	2.228	14	2.160
8	2.365	12	2.201	15	2.145
9	2.306				

* The values in this table are already corrected for n-1 degrees of freedom. Use n equal to the number of individual values. 40 CFR Part 60, App B, Spec. 1.

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RULE 2011 PROTOCOL- CHAPTER 5

REMOTE TERMINAL UNIT (RTU) - ELECTRONIC REPORTING

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CHAPTER 5 - REMOTE TERMINAL UNIT (RTU)

This chapter defines the tasks and characteristics for electronic reporting of emissions from all sources. The Facility Permit holder of a major source shall use an RTU to telecommunicate rule compliance data to the District Central Station Emissions Monitoring Computer. The RTU shall collect data, perform calculations, generate the appropriate data files, and transmit the data to the Central Station. The Facility Permit holder of a large source or process unit may elect to use an RTU. Alternatively, the Facility Permit holder of a large source or process unit shall compile the required rule compliance data manually, and transmit that data via modem in accordance with the data requirements of Section D in this chapter. The Facility Permit holder shall use, when required, the appropriate record type specified in this chapter to report to the District Central Station emissions from all RECLAIM NOx sources. Alternative to transmitting data to the District Central Station, the Facility Permit holder may use the District Internet Web Site to report emissions electronically from RECLAIM NOx sources except for major sources.

A. GENERAL

1. General

The Facility Permit holder of a major source shall telecommunicate rule compliance data to the District via Remote Terminal Units (RTU). This form of reporting may also be used for large sources or process units. The RTU shall collect data from a CEMS, a CPMS, or other equipment specified in the Facility Permit and send data periodically to the Central Station Emissions Monitoring Computer (Central Station).

This chapter specifies the tasks and characteristics required of the RTU and shall be used as a guide for providing the required software/hardware for the RTU. Emissions Data Collection System conformity as well as establishing and maintaining communications with the emission monitoring system and the Central Station shall be the responsibility of the Facility Permit holder. This chapter also serves as a functional guideline for operating requirements of the RTU, and provides information concerning RTU hardware/software procurement, configuration, installation, maintenance, and compatibility with the emission monitoring system and the Central Station.

2. RTU and Supporting Equipment Description

a. Purpose:

The RTU shall interface to existing data acquisition systems or other field instrumentation, and shall gather and store data, and facilitate telecommunication with the Central Station Computer.

b. Environment:

i. Logical Environment:
The signal chain includes the process equipment, sensing devices, data acquisition system, RTU, modem, communications link and District Central Station.

ii. Physical Environment:

Typical environments shall include "friendly" and "Central Station" environments. Friendly environments include clean, air conditioned areas such as computer rooms and offices. Hostile environments may include exterior spaces or interior spaces without benefit of air conditioning, and areas where free floating air particulates may impede the normal operation of exposed electronics. Each RTU shall be mounted in such a manner as to be environmentally qualified.

iii. Electrical Environment:

1) Connected Devices:
Each RTU may receive information from a local computer (DAS) or various field sensing devices, calculate and/or store the specified parameters and shall make its data available to local and Central Stations.

2) Sensor-based Data to be acquired:
Where applicable, the RTU shall be able to directly monitor transducers which sense variables required for compliance determinations. At a minimum, input analog conversion hardware should operate with a medium level of resolution (i.e. 12 bit resolution) and a sampling rate sufficient to accurately characterize the sensor based data.

iv. Description of Data to be transmitted:
All data shall be made available at data output ports in ASCII format as described below:

1) Data Sampling:
Shall retain selectable status levels about its sensors.

2) Rule-specific Data Sets:
(as specified elsewhere)

c. Functions:

The RTU shall provide the following functions:

i. Power-Up/Restart Mode:
Upon resumption of power after a loss, the RTU shall automatically restart and reset itself to predetermined system settings.

ii. Non-Communicating Mode:
When in the non-communicating mode the RTU shall operate independently of the communications ports as well as store its transactions for later communications with the Central Station.

iii. Failure Mode:
In the event the RTU is unable to initiate communications with the Central Station, the RTU shall perform the following actions:

1) The RTU shall first make four subsequent attempts to establish communications with the Central Station.

2) Upon failure of the fourth attempt, the RTU shall:
   a Revert to the non-communicating mode for a period of fifteen (15) minutes and then again attempt to establish communications with the Central Station.
   b Each failure shall result in the execution of the failure mode sequence.

3) Error Tolerance:
The RTU shall perform its specified functions without misinterpretation of input information, errors in output signals, damage to internal components, and loss or change of stored information with either common mode to ground or differential mode transients present on the communication ports, circuits or power sources which shall be connected to the inputs and power supply terminals to the equipment.

B. PRODUCTS

1. RTU Attributes

a. Environmental Tolerances: Each RTU shall be installed in such a manner as to be environmentally qualified for the particular physical environment.

b. Communications Provisions: The RTU shall provide a minimum of one (1) communications connection. The connection shall be labeled "Remote".

c. Real Time Clock: The RTU shall be equipped with a battery-backed Real Time Calendar/Clock (RTC) to provide time signals for implementing time dependent programs. The battery back-up shall be field replaceable and shall not require replacement more often than once every two (2) years. An alarm message shall be generated when the battery reaches a low voltage point with at least one (1) month life under load left prior to the necessity for battery replacement.

d. Internal Software:

i. Data Collection and Storage: The RTU shall collect data from sensors, generate and store values, and perform calculations upon those values. Data shall be collected and stored in the Data Sampling memory.

ii. Calculations and Message Storage: Calculated values and messages resulting from calculations performed upon sampled data shall be stored as ASCII data strings in memory.

e. Security Provisions:

i. Message Security: The RTU shall utilize a standard protocol encryption method for communications with the remote Central Station incorporating error detection. The system shall not incorporate error correction. The code shall detect one hundred (100) percent of single, double and triple errors; one hundred (100) percent of burst errors of six bits or fewer; ninety- seven (97) percent of all seven-bit bursts; and ninety-eight point four (98.4) percent of all other burst as well as a substantial fraction of all random error patterns involving more than three (3) bits.

ii. Message Checking: The RTU shall utilize bitsum checking for all messages.

f. Modem: Provide a modem connected to the Remote Central Station communication port.i.Modem Self-Test: The modem shall be capable of being operated in self testing mode automatically on a periodic basis.

g. Transient Suppression: Provide hardware, circuitry, components or extended component ratings or characteristics necessary to prevent interference to correct operation or equipment damage from induced transients which may be presented on communication circuits and power sources. Transient suppression shall utilize the latest revision of the ANSI C37.90a standard.

C. EXECUTION

1. General

a. Section (C) describes acceptable methods and practices for use in completion of this work.

b. Standards: Perform the work in accordance with the latest revisions of the following standards:

i. ANSI American National Standards Institute.

ii.	UL	Underwriters Laboratories.
iii.	EIA	Electrical Industries Association.
iv.	NEMA	National Electrical Manufacturers Association.

2. Project Plan

Develop a project plan for accomplishing the requirements of this installation . The plan shall include a checklist for the Submittal date .

3. Software Requirements Guideline

The Software Requirement Guideline (SRG) shall specify tasks and characteristics required of the RTU and is to be used as a guide for providing the required software for the RTU. Emissions Data Collection System conformity as well as establishing and maintaining communications with the emission monitoring system and the Central Station shall be the responsibility of the Facility Permit holder.

a. References

This guideline shall be used in conjunction with the following Rules:

RULE 2011 - Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Sulfur (SO_X) Emissions

RULE 2012 - Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Nitrogen (NO_X) Emissions

b. System Relation

The RTU shall be the local plant data storage and processing point in a system which is reporting data to a Central Station for evaluation to determine regulatory compliance. Data formats shall be standardized between the Central Station and all monitored emissions sources. It is the function of the RTU to convert as necessary the data stream from the local monitoring system. The fundamental operation of the RTU is to:

i. compile information from the emission monitoring system as specified in this guideline.

ii. transmit the compiled data to the Central Station on a scheduled basis.

c. Central Station Interface

On scheduled updates the RTU shall download current data to the Central Station. The RTU data buffer shall be reset after each successful download to the Central Station.

d. Software Responsibility

The Facility Permit holder shall be responsible for providing all RTU software required to perform all specified tasks. This may include purchased commercial software packages or custom written programs.

e. Product Function

i. Software Context and Data Flow Diagrams

The flow diagram at the end of this Chapter is a Context Diagram description and Data Flow Diagram which show how the different external functions tie to the RTU package. Plant data or operating information is collected by the emission monitoring system for evaluation of emissions. The RTU Unit is the process shown on this diagram and is the focus of this guideline.

Data Values relating to emissions received from the emission monitoring system are processed by the RTU into data files for transmission to the SCAQMD Central Station. The type of message is shown on the RTU Context Diagram between the RTU and the Central Station. The message is data sets which are sent periodically.

The RTU Data Flow Diagram is a graphical expansion of the RTU Unit process block. Emission monitoring system data is shown coming into the Network Driver and splitting to the other process blocks which represent RTU functions.

ii. Communication End Points

The RTU will communicate with both the emission monitoring system and the Central Station. Each end point has a different protocol and purpose. Data sent from the RTU to the Central Station shall be converted from floating point numbers used to perform calculations into ASCII standard to allow for different internal formats.

f. Specific Requirements

i. RTU Software

The main RTU program shall receive input data, do calculations (if necessary) and store all data in non-volatile memory, as it is received.

ii. Direct Field Input Data

Many RTUs may be capable of reading direct field inputs which shall consist of analog and/or digital real values. Direct field input requirements shall be specified as required for each RTU. Communications software shall be capable of supporting the hardware required to receive these inputs. If analog data cards must be installed in the RTU any resulting values provided to the RTU data bus shall range from -32768 to +32767 for unscaled values. The same accuracy as emission monitoring system network data shall be provided for analog data values scaled on the I/O device before going onto the RTU data bus.

iii. Input Data Conversion/Storage

All input values shall be stored in as received ASCII format. These values shall then be parsed and converted to real numbers for calculations and averaging.iv. Output Data To Central Station

The context diagram displays how the RTU software shall be configured to allow messages to be sent to the Central Station. File transfer for all messages shall be in ASCII format including a bitsum check value with a return acknowledgment expected by the RTU when the Central Station has verified the bitsum check.

v. RTU To Central Station Communications Failure

If the RTU cannot communicate with the Central Station the main program shall store all calculated values and reports in a special file in non-volatile memory. These special files shall be labeled to show that they have not been acknowledged as received by the Central Station.

g. Performance Requirements

i. Speed of Receiving DATA

Incoming data from the plant or emission monitoring system shall be received at intervals specified in the appropriate emission monitoring guideline. Communication with the Central Station, Parsing, verification, storage and checking shall not block the receipt of new data.

ii. RTU Non-Volatile Memory

The RTU non-volatile memory shall have enough capacity to store all programs, data parameters, emission monitoring system input data and calculated data averages. Input data and calculated averages shall be allocated space using the first in first out (FIFO) method to store the quantity of data as required.

h. Design Restraints

i. Data Set Formats

Section (D) indicates the data format that is to be sent to the Central Station at scheduled intervals. The Central Station will send a confirmation message back for each transmission received which will consist of an identification number unique to the Central Station and a transaction number which is sequentially issued.

i. RTU External Interface Requirements

i. Central Station Interface

External interface to the RTU is shown on the Context Diagram at the end of this chapter. Central Station interface is described above as fixed format ASCII messages using a commercially available communication software package. In return the Central Station will send confirmation messages in ASCII form when a satisfactory message transfer has been completed.

4. Required Installation Practices

a. Standards: Install all devices in accordance with the standards set forth herein and in accordance with manufacturers recommendations and first class standard industry practice.

b. Telephone Interface:

RTU shall operate on a standard analog telephone line. Label the remote Central Station communications connector with the telephone number to which it is connected.

5. Submittals

a. Shop Drawing:

i. Submit two (2) copies of the following in accordance with the applicable rule compliance dates.

- A Title Sheet
- Single Line Diagrams
- Wiring Diagrams or Run Sheets
- Physical Details of Custom Assemblies

ii. Descriptions of the above shop drawings are as follows:

a) Title Sheet containing a drawing list, abbreviations list, symbols list and schedules.

b) Single-Line Diagram for each system showing signal relationships of devices within the system and device nomenclatures.

c) Wiring Diagram for each assembly or enclosure or free standing device, showing the following:

1) the layout of the devices within;

2) wiring connections;

3) wire numbers;

4) voltage levels, and

5) fuse values and types.

d) Physical Details of contractor fabricated assemblies:

1) Provide an assembly drawing showing the finished product. Show components comprising the assembly by manufacturer and model number.

2) Provide a schematic diagram of the assembly, as described above.

b. RTU Components List:

i. The RTU Component List shall contain the following information for all materials, components, devices, wire and equipment used:

- Quantity for that system.
- Description (generic).

- Manufacturers Name and Model number.

c. Software Design Description (SDD). Indicate how the developed software will meet the defined software requirements. The SDD shall be based on ANSI/IEEE standards, specifically 1016 (SDD) and 730 (Quality Assurance).

d. Software Listing. Provide a source code listing of all developed software required by the applicable emission monitoring requirements.

D. DATA REQUIREMENTS

1. General Requirements

The District will accept data in the American Standard Code for Information Interchange (ASCII) format.

The data file structure must be sequential. The record delimiter - a ~ (tilde) occurs only once following the end of each data record. There must be no delimiter before the first data record. The ASCII value for the delimiter is:

~ (decimal 126)

Blank data records must not be reported

In text fields, only upper case characters are to be used and must be left justified. Text fields that are not applicable must be filled with blanks. The ~ character (decimal 126) must never appear inside text fields.

Numeric fields must be right justified and zero filled. Where decimal places are to be reported, they are to be implied - do not include the decimal point character. Numeric fields that are zeros or not applicable, must be zero filled.

Date fields must be entered in the format "YYYYMMDD" and must always specify a valid date.

2. Data File Description

A properly composed data file is comprised of the following data records (shown indented to illustrate the logical grouping):

Code 1A	- Transmitter Record
Code 1F	- Facility Record
	Emission data record(s) from any of the following data records
Code 1NP	- NO_X Process Unit and Large Source Record
Code 1NM	- NO_X Major Source Record

Code 1SP	- SO_X Process Unit Record
Code 1SM	- SO_X Major Source Record
Code 1FT	- Facility Total Record
Code 1F	- Facility Record
	Emission data record(s)
Code 1FT	- Facility Total Record
Code 1T	- Final Total Record

The Code 1A data record identifies the facility submitting the data file and must be the first data record in the data file.

The Code 1T data record identifies the end of a data file and must be the last data record in the data file

The Code 1F data record identifies the facility whose emission data records are being reported.

The Code 1FT data record identifies the end of emission data records for a particular facility.

Code 1F/1FT data records must not be nested inside of another 1F/1FT group and are repeated for each facility to be reported.

Emission data records for a facility are reported following the Code 1F but before the 1FT data record for that facility and can comprise any of the following data record types:

Code 1NP	- NO_X Process Unit and Large Source Record
Code 1NM	- NO_X Major Source Record
Code 1SP	- SO_X Process Unit Record
Code 1SM	- SO_X Major Source Record

The following table summarizes valid Record Identifiers to be used starting January 1, 1998 to perform electronic reporting via a RTU or modem. The 1A through 1T records are used for identification and grouping purposes. The 1NP through 1SM records are the pre-existing emissions reporting records. Starting January 1, 1998, these records may only be used for devices which do not use multiple fuels and are not involved in multiple processes. Otherwise, sources shall report emissions by each fuel type or process conducted within the reporting period. If more than 50% of the emissions from a source is from the combustion of fuels, the emission report for such a source or process unit shall be reported based on the fuel combusted. Otherwise, emissions shall be reported based on the Source Classification Code (SCC) for the process conducted. The 1NPF through 1SUQ records are utilized for reporting emissions from devices with multiples fuels or processes. Record Identifiers starting with "2" are used to make corrections to submitted electronic emissions reports. Record Identifiers starting with "3" are used to delete previously submitted electronic emissions reports which were filed erroneously. Erroneous records to be corrected need not be deleted first.

Record Identifiers Summary Table

Record Identifier for			Description
Adding a record	Updating a record	Deleting a record	
1A*	--	--	Transmitter Record
1F*	--	--	Facility Record
1FT*	--	--	Facility Total Record
1T*	--	--	Final Total Record
1NP*	2NP	3NP	NOx Emissions Report for Process Units
1NL*	2NL	3NL	NOx Emissions Report for Large Sources
1NM*	2NM	3NM	NOx Emissions Report for Major Sources
1SP*	2SP	3SP	SOx Emissions Report for Process Units
1SM*	2SM	3SM	SOx Emissions Report for Major Sources
1NPF	2NPF	3NPF	NOx Emissions Report for Process Units by Fuel Type
1SPF	2SPF	3SPF	SOx Emissions Report for Process Units by Fuel Type
1NLF	2NLF	3NLF	NOx Emissions Report for Large Sources by Fuel Type
1NMF	2NMF	3NMF	NOx Emissions Report for Major Sources by Fuel Type
1SMF	2SMF	3SMF	SOx Emissions Report for Major Sources by Fuel Type
1NPS	2NPS	3NPS	NOx Emissions Report for Process Units by SCC
1SPS	2SPS	3SPS	SOx Emissions Report for Process Units by SCC
1NLS	2NLS	3NLS	NOx Emissions Report for Large Sources by SCC
1NMS	2NMS	3NMS	NOx Emissions Report for Major Sources by SCC
1SMS	2SMS	3SMS	SOx Emissions Report for Major Sources by SCC
1NMM	2NMM	3NMM	Monthly NOx Emissions Report for Major Sources
1SMM	2SMM	3SMM	Monthly SOx Emissions Report for Major Sources
1NMQ	2NMQ	3NMQ	Quarterly NOx Emissions Report for Major Sources
1SMQ	2SMQ	3SMQ	Quarterly SOx Emissions Report for Major Sources
1NLQ	2NLQ	3NLQ	Quarterly NOx Emissions Report for Large Sources
1NRF	2NRF	3NRF	Quarterly NOx Emissions Report by fuel type for Rule 219 Exempt Equipment
1SRF	2SRF	3SRF	Quarterly SOx Emissions Report by fuel type for Rule 219 Exempt Equipment
1NRS	2NRS	3NRS	Quarterly NOx Emissions Report by SCC for Rule 219 Exempt Equipment
1SRS	2SRS	3SRS	Quarterly SOx Emissions Report by SCC for Rule 219 Exempt Equipment
1NVF	2NVF	3NVF	Quarterly NOx Emissions Report by fuel type for Equipment Operating under a Various Locations Permit
1SVF	2SVF	3SVF	Quarterly SOx Emissions Report by fuel type for Equipment Operating under a Various Locations Permit
1NVS	2NVS	3NVS	Quarterly NOx Emissions Report by SCC for Equipment Operating under a Various Locations Permit
1SVS	2SVS	3SVS	Quarterly SOx Emissions Report by SCC for Equipment Operating under a Various Locations Permit
1NWF	2NWF	3NWF	Quarterly NOx Emissions Report by fuel type for Equipment Operating Without Permit or District assigned Device IDs
1SWF	2SWF	3SWF	Quarterly SOx Emissions Report by fuel type for Equipment Operating Without Permit or District assigned Device IDs
1NWS	2NWS	3NWS	Quarterly NOx Emissions Report by SCC for Equipment Operating Without Permit or District assigned Device IDs
1SWS	2SWS	3SWS	Quarterly SOx Emissions Report by SCC for Equipment Operating Without Permit or District assigned Device IDs
1NPQ	2NPQ	3NPQ	Quarterly NOx Aggregate Emissions Report for Process Units

Record Identifiers Summary Table (cont.)

Record Identifier for			Description
Adding a record	Updating a record	Deleting a record	
1SPQ	2SPQ	3SPQ	Quarterly SOx Aggregate Emissions Report for Process Units
1NXQ	2NXQ	3NXQ	Quarterly NOx Aggregate Emissions Report for Rule 219 Exempt Equipment
1SXQ	2SXQ	3SXQ	Quarterly SOx Aggregate Emissions Report for Rule 219 Exempt Equipment
1NTQ	2NTQ	3NTQ	Quarterly NOx Aggregate Emissions Report for Equipment Operating under a Various Locations Permit
1STQ	2STQ	3STQ	Quarterly SOx Aggregate Emissions Report for Equipment Operating under a Various Locations Permit
1NUQ	2NUQ	3NUQ	Quarterly NOx Aggregate Emissions Report for Equipment Operating without a Permit
1SUQ	2SUQ	3SUQ	Quarterly SOx Aggregate Emissions Report for Equipment Operating without a Permit

* Previously defined codes

Code 1A - Transmitter Record

The Code 1A data record is used to identify the facility submitting the data file and must be the first data record reported.

Location	Field	Length	Description
1-4	Record Identifier	4	Constant "1A" followed by 2 blanks.
5-10	SCAQMD Facility ID	6	The 6-digit SCAQMD facility ID of the facility submitting the data file.
11-128	Filler	118	Blanks , used to fill unused remaining record positions.

Code 1F - Facility Record

The Code 1F data record is used to identify the facility whose emissions are being reported.

Location	Field	Length	Description
1-4	Record Identifier	4	Constant "1F" followed by 2 blanks.
5-10	SCAQMD Facility ID	6	The 6-digit SCAQMD facility ID for the facility whose emissions are being reported.
11-128	Filler	118	Blanks , used to fill unused remaining record positions.

Code 1FT - Facility Total Record

The Code 1FT data record is used to identify the end of data emission records for a facility.

Location	Field	Length	Description
1-4	Record Identifier	4	Constant "1FT" followed by 1 blank.
5-11	Number of Emission Data Records	7	The total number of emission data records reported for the facility (excluding the 1F and the 1FT data records). Right justify and zero fill.
12-128	Filler	117	Blanks , used to fill unused remaining record positions.

Code 1T - Final Total Record

The Code 1T data record is used to identify the end of the data file and must be the last data record reported.

Location	Field	Length	Description
1-4	Record Identifier	4	Constant "1T" followed by 2 blanks
5-11	Number of Data	7	The total number of data records reported (including the Code 1T) in the data file. Right justify and zero fill.
12-128	Filler	117	Blanks , used to fill unused remaining record positions.

Code 1NP and 1NL- NO_X Process Unit and Large Source Record

The Code 1NP data record is used to report NO_X emissions from NO_X Process Units with SCAQMD assigned Device Ids. The Code 1NL data record is used to report NOx emissions from NOx Large Sources with SCAQMD assigned Device IDs. Starting January 1, 1998, these records shall only be used for devices which do not use multiple fuels and are not involved in multiple processes.

Location	Field	Length	Description
1-4	Record Identifier	4	"1NP" or "1NL"followed by 1 blank
5-10	SCAQMD Device ID	6	The SCAQMD assigned Device IDs for the equipment source. Left justify and fill with blanks
11-18	Date Emitted	8	The date emitted in the format "YYYYMMDD"
19-27	Total Emission	9(#######.##)	The total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
28 - 128	Filler	101	Blanks , used to fill unused remaining record positions

Code 1NM - NOx Major Source Record

The Code 1NM data record is used to report NO_X emissions from Major NO_X sources with SCAQMD assigned Device IDs. Starting January 1, 1998, this record shall only be used for devices which do not use multiple fuels and are not involved in multiple processes.

Location	Field	Length	Description
1-4	Record Identifier	4	Constant "1NM" followed by 1 blank
5-10	SCAQMD Device ID	6	The SCAQMD assigned Device IDs for the equipment source. Left justify and fill with blanks
11-18	Date Emitted	8	The date emitted in the format "YYYYMMDD"
19-27	Total Emission	9(#######.##)	The total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
28-36	Status Word	9	The nine character status word for the reporting day from the Status Word Table.
37 - 128	Filler	92	Blanks , used to fill unused remaining record positions

Code 1SP - SO_X Process Unit Record

The Code 1SP data record is used to report SOx emissions from SOx Process Units with SCAQMD assigned Device IDs. Starting January 1, 1998, this record shall only be used for devices which do not use multiple fuels and are not involved in multiple processes.

Location	Field	Length	Description
1-4	Record Identifier	4	Constant "1SP"followed by 1 blank
5-10	SCAQMD Device ID	6	The SCAQMD assigned Device IDs for the equipment source. Left justify and fill with blanks
11-18	Date Emitted	8	The date emitted in the format "YYYYMMDD"
19-27	Total Emission	9(#######.##)	The total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
28 - 128	Filler	101	Blanks , used to fill unused remaining record positions

Code 1SM - SOx Major Source Record

The Code 1SM data record is used to report SOx emissions from Major SOx sources with SCAQMD assigned Device IDs. Starting January 1, 1998, this record shall only be used for devices which do not use multiple fuels and are not involved in multiple processes.

Location	Field	Length	Description
1-4	Record Identifier	4	Constant "1SM" followed by 1 blank
5-10	SCAQMD Device ID	6	The SCAQMD assigned Device IDs for the equipment source. Left justify and fill with blanks
11-18	Date Emitted	8	The date emitted in the format "YYYYMMDD"
19-27	Total Emission	9(#######.##)	The total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
28-36	Status Word	9	The nine character status word for the reporting day from the Status Word Table.
37 - 128	Filler	92	Blanks , used to fill unused remaining record positions

Code 1NMF and 1SMF - NOx and SOx Major Source Emissions Report by Fuel Type

The Codes 1NMF and 1SMF data records are used to report NOx and SOx emissions by fuel type from Major SOx sources with SCAQMD assigned Device IDs. Starting January 1, 1998, these records shall be used to report emissions from each Major SOx sources and each fuel used during a reporting day.

Location	Field	Length	Description
1-4	Record Identifier	4	1NMF or 1SMF
5-10	SCAQMD Device ID	6	The SCAQMD assigned Device IDs for the equipment source. Left justify and fill with blanks
11-18	Date Emitted	8	The date emitted in the format "YYYYMMDD"
19-38	Fuel Type	20	Code for Fuel Type utilized. Left justified, blank filled
39-47	Total Emission	9(#######.##)	The total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
48-56	Status Word	9	The nine character status word for the reporting day from the Status Word Table.
57 - 128	Filler	72	Blanks , used to fill unused remaining record positions

Code 1NMS and 1SMS - NOx and SOx Major Source Emissions Report by SCC

The Codes 1NMS and 1SMS data records are used to report NOx and SOx emissions by Source Classification Codes (SCC) from Major SOx sources with SCAQMD assigned Device IDs. Starting January 1, 1998, these records shall be used to report emissions from each Major SOx sources and each process conducted during a reporting day.

Location	Field	Length	Description
1-4	Record Identifier	4	1NMS or 1SMS
5-10	SCAQMD Device ID	6	The SCAQMD assigned Device IDs for the equipment source. Left justify and fill with blanks
11-18	Date Emitted	8	The date emitted in the format "YYYYMMDD"
19-26	SCC	8	Source Classification Code
27-35	Total Emission	9(#######.##)	The total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
36-44	Status Word	9	The nine character status word for the reporting day from the Status Word Table.
45 - 128	Filler	84	Blanks , used to fill unused remaining record positions

Code 1NLF, 1NPF and 1SPF - NOx Large Source and NOx and SOx Process Unit Emissions Report by Fuel Type

The Codes 1NLF, 1NPF and 1SPF data records are used to report NOx and SOx emissions by fuel type from NOx Large source, NOx and SOx Process Units, respectively, with SCAQMD assigned Device IDs. Starting January 1, 1998, these records shall be used to report emissions from each device and each fuel used during a reporting period.

Location	Field	Length	Description
1-4	Record Identifier	4	1NLF, 1NPF, or 1SPF
5-10	SCAQMD Device ID	6	The SCAQMD assigned Device IDs for the equipment source. Left justify and fill with blanks
11-18	Date Emitted	8	End date of reporting period in the format "YYYYMMDD"
19-38	Fuel Type	20	Code for Fuel Type utilized. Left justified, blank filled
39-47	Total Emission	9(#######.##)	The total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
48-56	Status Word	9	The nine character status word for the reporting day from the Status Word Table.
57 - 128	Filler	72	Blanks , used to fill unused remaining record positions

Code 1NLS, 1NPS and 1SPS - NOx Large Source and NOx and SOx Process Units Emissions Report by SCC

The Codes 1NLS, 1NPS and 1SPS data records are used to report NOx and SOx emissions by SCC from NOx Large source, NOx and SOx Process Units, respectively, with SCAQMD assigned Device IDs. Starting January 1, 1998, these records shall be used to report emissions from each device and each process conducted during a reporting period.

Location	Field	Length	Description
1-4	Record Identifier	4	1NLS, 1NPS, or 1SMS
5-10	SCAQMD Device ID	6	The SCAQMD assigned Device IDs for the equipment source. Left justify and fill with blanks
11-18	Date Emitted	8	End date of reporting period in the format "YYYYMMDD"
19-26	SCC	8	Source Classification Code
27-35	Total Emission	9(#######.##)	The total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
36-44	Status Word	9	The nine character status word for the reporting day from the Status Word Table.
45 - 128	Filler	84	Blanks , used to fill unused remaining record positions

Code 1NMM, 1SMM, 1NMQ, 1NLQ, 1NPQ, 1SMQ, and 1SPQ - Aggregate Emissions Reports for Devices with District Assigned Device IDs

The Codes 1NMM and 1SMM data records are used to report monthly total NOx and SOx emissions, respectively, from all NOx and SOx Major Sources within a facility. The Codes 1NMQ, 1SMQ, 1NLQ, 1NPQ, and 1SPQ data records are used to report quarterly total NOx and SOx emissions, respectively, from all NOx and SOx Major, NOx Large Sources, and NOx and SOx Process Units within a facility. Starting January 1, 1998, these records shall be used to report aggregate emissions from applicable classification of devices within each facility.

Location	Field	Length	Description
1-4	Record Identifier	4	1NMM, 1SMM, 1NMQ, 1SMQ, 1NLQ, 1NPQ, or 1SPQ
5-12	Date Emitted	8	End date of the reporting period in the format "YYYYMMDD"
13-21	Total Emission	9(#######.##)	Enter the total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
22 - 128	Filler	107	Blanks , used to fill unused remaining record positions

Code 1NXQ, 1SXQ, 1NTQ, 1STQ, 1NUQ, and 1SUQ - Aggregate Quarterly Emissions Reports for Devices without District Assigned Device IDs

The Code 1NXQ, 1SXQ, 1NTQ, 1STQ, 1NUQ, and 1SUQ data records are used to report quarterly total NOx and SOx emissions, respectively, from all Rule 219 exempt equipment, equipment operating under a various locations permit (e.g. rental equipment) and equipment without permit. Starting January 1, 1998, these records shall be used to report aggregate emissions from all applicable devices within each facility.

Location	Field	Length	Description
1-4	Record Identifier	4	1NXQ, 1SXQ, 1NTQ, 1STQ, 1NUQ, and 1SUQ
5-12	Date Emitted	8	End date of the reporting period in the format "YYYYMMDD"
13-21	Total Emission	9(#######.##)	Enter the total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
22 - 128	Filler	107	Blanks , used to fill unused remaining record positions

Code 1NVF and 1SVF - NOx and SOx Emissions Reports by Fuel Type for Equipment Operated under a Various Locations Permit

The Code 1NVF and 1SVF data records are used to report NOx and SOx emissions, respectively, by fuel type from each device operating under a various location permit (e.g. rental equipment). Starting January 1, 1998, these records shall be used to report emissions from each device in this category.

Location	Field	Length	Description
1-4	Record Identifier	4	1NVF or 1SVF
5-10	Permit Number	6	SCAQMD Permit Number. Left justified, blank filled
11-18	Date Emitted	8	End date of the reporting period in the format "YYYYMMDD"
19-38	Fuel Type	20	Code for Fuel Type utilized. Left justified, blank filled
39-47	Total Emission	9(#######.##)	Enter the total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
47 - 128	Filler	82	Blanks , used to fill unused remaining record positions

Code 1NVS and 1SVS - NOx and SOx Emissions Reports by SCC for Equipment Operated under a Various Locations Permit

The Code 1NVF and 1SVF data records are used to report NOx and SOx emissions, respectively, by SCC from each device operating under a various location permit (e.g. rental equipment). Starting January 1, 1998, these records shall be used to report emissions from each device in this category.

Location	Field	Length	Description
1-4	Record Identifier	4	1NVS or SVS
5-10	Permit Number	6	SCAQMD Permit Number. Left justified, blank filled
11-18	Date Emitted	8	End date of the reporting period in the format "YYYYMMDD"
19-26	SCC	8	Source Classification Code.
27-35	Total Emission	9(#######.##)	Enter the total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
36 - 128	Filler	93	Blanks , used to fill unused remaining record positions

Code 1NRF, 1SRF, 1NWF, and 1SWF - NOx and SOx Emissions Reports by Fuel Type for Rule 219 Exempt Equipment, and Equipment Operated without a Permit

Code 1NRF, 1SRF, 1NWF, and 1SWF are used to report NOx and SOx emissions by fuel type from all devices which are exempt from permit under Rule 219 or from all devices operating without a permit. Starting January 1, 1998, these records shall be used to report emissions from all devices in each of these category.

Location	Field	Length	Description
1-4	Record Identifier	4	1NRF, 1SRF, 1NWF, or 1SWF
5-12	Date Emitted	8	End date of the reporting period in the format "YYYYMMDD"
13-32	Fuel Type	20	Code for Fuel Type utilized. Left justified, blank filled
33-41	Total Emission	9(#######.##)	Enter the total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
42 - 128	Filler	82	Blanks , used to fill unused remaining record positions

Code 1NRS, 1SRS, 1NWS, and 1SWS - NOx and SOx Emissions Reports by SCC for Rule 219 Exempt Equipment, and Equipment Operated without a Permit

Code 1NRS, 1SRS, 1NWS, and 1SWS are used to report NOx and SOx emissions by SCC from all devices which are exempt from permit under Rule 219 or from all devices operating without a permit. Starting January 1, 1998, these records shall be used to report emissions from all devices in each of these category.

Location	Field	Length	Description
1-4	Record Identifier	4	1NRS, 1SRS, 1NWS, or 1SWS
5-12	Date Emitted	8	End date of the reporting period in the format "YYYYMMDD"
13-20	SCC	8	Source Classification Code.
21-29	Total Emission	9(#######.##)	Enter the total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
30-128	Filler	99	Blanks , used to fill unused remaining record positions

Status Word Table

The Status Word Table is used to compile the status word for the required reporting period. True is 1 and False is 0.

Location	Field	Length	Description
1-1	Valid Data	1	Enter true if valid data was obtained for the entire reporting period, else enter false
2-2	Calibration	1	Enter true if the monitoring system was calibrated during the reporting period, else enter false
3-3	Off-line	1	Enter true if the monitoring system was off-line at any time during the reporting period, else enter false.
4-4	Alternate Data Acquisition	1	Enter true if alternate data acquisition was used during the reporting period, else enter false.
5-5	Out of Control	1	Enter true if the CEMS was out of control during the reporting period, else enter false.
6-6	Fuel Switch	1	Enter true if more than one fuel type was used during the reporting period, else enter false.
7-7	10% range	1	Enter true if concentration was reported at 10% valid range when concentration value was below 10%, else enter false.
8-8	lower than 10% range	1	Enter true if concentration was reported at an actual value less than 10% valid range, else enter false.
9-9	non-operational	1	Enter true if the RECLAIM SOx source being monitored is non-operational for the entire day, else enter false.

Format for Correcting Emissions Reports

Name	Description
Record Identifier	Record Identifier starting with "2"
Record to be corrected	All information contained in previously submitted record which is to be corrected, except the original Record Identifier field and the filler field.
Correct Record	The correct record containing all information for the record type, except the original Record Identifier field and the filler field.
Filler	This field is blank filled to complete the 128 character fixed length reporting record.

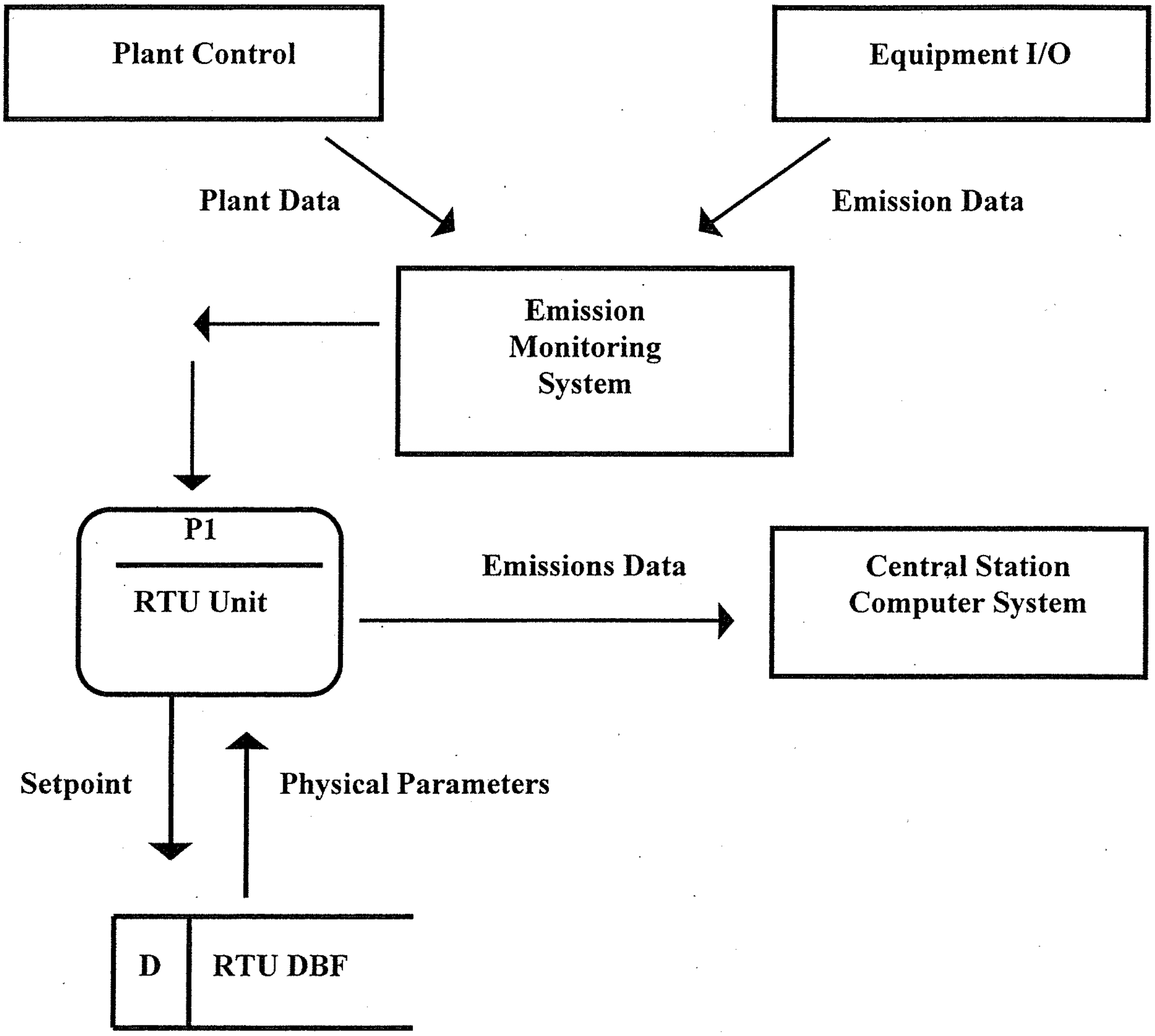
Format for deleting Emissions Reports

Name	Description
Record Identifier	Record Identifier starting with "3"
Record to be deleted	All information contained in previously submitted record which is to be deleted, except the original Record Identifier field and the filler field.

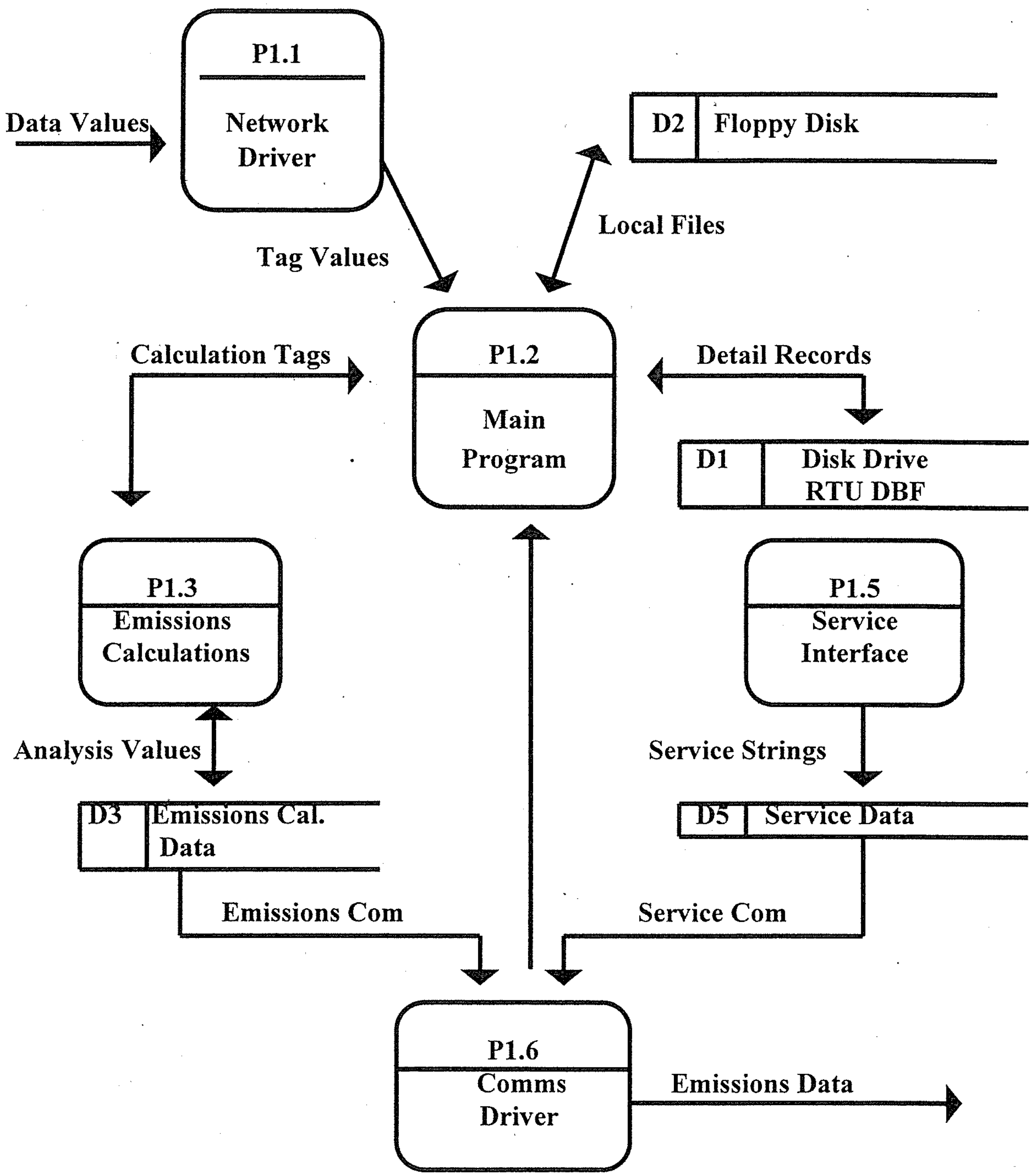
APPENDIX G

DIAGRAMS

RTU Context Diagram



RTU Data Flow Diagram



7/15/05

RULE 2011 PROTOCOL-
CHAPTER 6

REFERENCE METHODS

District Method 1.1 - Sample and velocity traverses for stationary sources

District Method 1.2 Sample and velocity traverse for stationary sources with small stacks or ducts

District Method 2.1 - Determination of stack gas velocity and volumetric flow rate (S-type Pitot tube)

District Method 2.2 - Direct measurement of gas volume through pipes and small ducts

District Method 2.3 - Determination of gas velocity and volumetric flow rate from small stacks or ducts

District Method 3.1 - Gas analysis for dry molecular weight and excess air

District Method 4.1 - Determination of moisture content in stack gases

District Method 6.1 - Determination of sulfuric acid and sulfur oxides from stationary sources.

District Method 100.1 - Instrumental analyzer procedures for continuous gaseous emission sampling

District Method 307.91 - Determination of sulfur in a gaseous matrix

EPA Method 6 - Determination of sulfur dioxide emissions from stationary sources

EPA Method 19 - Determination of sulfur dioxide removal efficiency and particulate, sulfur dioxide and nitrogen oxides emission rates from electric utility steam generator (40 CFR Part 60 Appendix A)

ASTM Method D 4294 or D 2622-82 - Determination of sulfur in liquid fuels

RULE 2011 PROTOCOL-
ATTACHMENT A

1 N PROCEDURE

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ATTACHMENT A
1 N PROCEDURE

A. APPLICABILITY

1. This procedure may be used to provide substitute data for affected sources that meet the specified conditions in Chapter 2, Subdivision E, Paragraph 1, Subparagraph b, clause i and Chapter 2, Subdivison E, Paragraph 2, Subparagraph c, clause i.

B. PROCEDURE

1. Where N is the number of hours of missing emissions data, determine the substitute hourly SO_X concentration (in ppmv), the fuel gas sulfur content (in ppmv), or the hourly flow rate (in scfh) by averaging the measured or substituted values for the 1N hours immediately before the missing data period and the 1N hours immediately after the missing data period.

2. Where 1N hours before or after the missing data period includes a missing data hour, the substituted value previously recorded for such hour(s) pursuant to the missing data procedure shall be used to determine the average in accordance with Subdivision B, Paragraph 1 above.

3. Substitute the calculated average value for each hour of the N hours of missing data.

EXAMPLES OF 1 N PROCEDURE

EXAMPLE 1

HOUR	DATA POINT (LB/HR)
1:00 A.M.	30
2:00 A.M.	25
3:00 A.M	32
4:00 A.M.	34
5:00 A.M.	Missing
6:00 A.M.	Missing
7:00 A.M.	Missing
8:00 A.M.	27
9:00 A.M.	22
10:00 A.M.	25
11:00 A.M	30

To fill in the missing three hours, take the data points from the 3 hours before and the 3 hours after the missing data period to determine an average emission over the 3 hours

$$\text{average emissions} = \frac{25 + 32 + 34 + 27 + 22 + 25}{6} = 27.5 \text{ lb/hr.}$$

The filled in data set should read as follows:

EXAMPLE 1 (continued)

HOUR	DATA POINT (LB/HR)
1:00 A.M.	30
2:00 A.M.	25
3:00 A.M.	32
4:00 A.M.	34
5:00 A.M.	27.5
6:00 A.M.	27.5
7:00 A.M.	27.5
8:00 A.M.	27
9:00 A.M.	22
10:00 A.M.	25
11:00 A.M.	30

EXAMPLES OF 1 N PROCEDURE

EXAMPLE 2

HOUR	DATA POINT (LB/HR)
1:00 A.M.	45
2:00 A.M.	50
3:00 A.M.	53
4:00 A.M.	Missing
5:00 A.M.	Missing
6:00 A.M.	Missing
7:00 A.M.	58
8:00 A.M.	Missing
9:00 A.M.	48
10:00 A.M.	45

In this example the missing data point at 8 A.M. is in the 3-hour period after the 3- hour missing data period. We first fill the 8.A.M. slot.

average emissions for 8 A.M. = $\frac{58+48}{2}$ = 53

The filled in data sheet at this point should read as follows:

EXAMPLE 2 (continued)

HOUR	DATA POINT (LB/HR)
1:00 A.M.	45
2:00 A.M.	50
3:00 A.M.	53
4:00 A.M.	Missing
5:00 A.M.	Missing
6:00 A.M.	Missing
7:00 A.M.	58
8:00 A.M.	53
9:00 A.M.	48
10:00 A.M.	45

The average for the three hour missing data period is:

average emissions = $\frac{45 + 50 + 53 + 58 + 53 + 48}{6}$ = 51.2

The completed filled in data sheet should read as follows:

EXAMPLE 2 (continued)

HOUR	DATA POINT (LB/HR)
1:00 A.M.	45
2:00 A.M.	50
3:00 A.M.	53
4:00 A.M.	51.2
5:00 A.M.	51.2
6:00 A.M.	51.2
7:00 A.M.	58
8:00 A.M.	53
9:00 A.M.	48
10:00 A.M.	45

RULE 2011 PROTOCOL-ATTACHMENT B

BIAS TEST

ATTACHMENT B

BIAS TEST

The bias of the data shall be determined based on the relative accuracy (RA) test data sets and the relative accuracy test audit (RATA) data sets for SOx pollutant concentration monitors, fuel gas sulfur content monitors, flow monitors, and emission rate measurement systems using the procedures outlined below.

1. Calculate the mean of the difference using Equation 2-1 of 40 CFR, Part 60, Appendix B, Performance Specification 2. To calculate bias for an SOx pollutant concentration monitor, "d" shall, for each paired data point, be the difference between the SOx concentration values (in ppmv) obtained from the reference method and the monitor. To calculate bias for a fuel gas sulfur content monitor, "d" shall, for each paired data point, be the difference between the fuel gas sulfur concentration values (in ppmv) obtained from the reference method and the -monitor. To calculate bias for a flow monitor, "d" shall, for each paired data point, be the difference between the flow rate values (in scfh) obtained from the reference method and the monitor. To calculate bias for an emission rate measurement system, "d" shall, for each paired data point, be the difference between the emission rate values (in lb/hr) obtained from the reference method and the monitoring system.

2. Calculate the standard deviation, Sd, of the data set using Equation 2-2 of 40 CFR, Part 60, Appendix B, Performance Specification 2.

3. Calculate the confidence coefficient, cc, of the data set using Equation 2-3 of 40 CFR, Part 60, Appendix B, Performance Specification 2.

4. The monitor passes the bias test if it meets either of the following criteria:

   a. the absolute value of the mean difference is less than |cc|.

   b. the absolute value of the mean difference is less than 1 ppmv.

5. Alternatively, if the monitoring device fails to meet the bias test requirement, the Facility Permit holder may choose to use the bias adjustment procedure as follows:

   a. If the CEMS is biased high relative to the reference method, no correction will be applied.

b. If the CEMS is biased low relative to the reference method, the data shall be corrected for bias using the following procedure:

$$CEM_i^{adjusted} = CEM_i^{monitored} \times BAF \qquad \text{(Eq. B-1)}$$

where:

$CEM_i^{adjusted}$ = Data value adjusted for bias at time i.

$CEM_i^{monitored}$ = Data provided by the CEMS at time i.

BAF = Bias Adjustment Factor

$$BAF = 1 + (|d|/CEM) \qquad \text{(Eq. B-2)}$$

where:

d = Arithmetic mean of the difference between the CEMS and the reference method measurements during the determination of the bias.

CEM = Mean of the data values provided by the CEMS during the determination of bias.

If the bias test failed in a multi-level RA or RATA, calculate the 13AF for each operating level. Apply the largest BAF obtained to correct for the CEM data output using equation B-1. The facility permit holder shall have the option to apply this adjustment to either all directly monitored data or to emission rates from the time and date of the failed bias test until the date and time of a RATA that does not show bias. These adjusted values shall be used in all forms of missing data computation, and in calculating the mass emission rate.

The BAF is unique for each CEMS. If backup CEMS is used, any BAF applied to primary CEMS shall be applied to the backup CEMS unless there are RATA data for the backup CEMS within the previous year.

If the BAF changes during a RATA, the new BAF must be applied to the emissions data from the time and date of the RATA until the time and date of the next RATA.

The BAF is unique for each CEMS. If backup CEMS is used, any BAF applied to primary CEMS shall be applied to the backup CEMS unless there are RATA data for the backup CEMS within the previous year.

3/17/17

SOUTH COAST AIR QUALITY MANAGEMENT DISCTRICT

RULE 2011 PROTOCOL- ATTACHMENT C

QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

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ATTACHMENT C - QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

ATTACHMENT C

QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

A. QUALITY CONTROL PROGRAM

Develop and implement a quality control program for the continuous emission monitoring systems and their components. As a minimum, include in each quality control program a written plan that describes in detail complete, step-by-step procedures and operations for each of the following activities:

1. Calibration Error Test Procedures

Identify calibration error test procedures specific to the CEMS that may require variance from the procedures used during certification (for example, how the gases are to be injected, adjustments of flow rates and pressures, introduction of reference values, length of time for injection of calibration gases, steps for obtaining calibration error, determination of interferences, and when calibration adjustments should be made).

2. Calibration and Linearity Adjustments

Explain how each component of the CEMS shall be adjusted to provide correct responses to calibration gases, reference values, and/or indications of interference both initially and after repairs or corrective action. Identify equations, conversion factors, assumed moisture content, and other factors affecting calibration of each CEMS.

3. Preventative Maintenance

Keep a written record of procedures, necessary to maintain the CEMS in proper operating condition and a schedule for those procedures.

4. Audit Procedures

Keep copies of written reports received from testing firms/laboratories of procedures and details specific to the installed CEMS that were to be used by the testing firms/laboratories for relative accuracy test audits, such as sampling and analysis methods. The testing firms/laboratories shall have received approval from the District by going through the District's laboratory approval program.

5. Record Keeping Procedures

Keep a written record describing procedures that shall be used to implement the record keeping and reporting requirements.

Specific provisions of Section A-3 and A-5 above of the quality control programs shall constitute specific guidelines for facility personnel. However, facilities shall be required to take reasonable steps to monitor and assure implementation of such specific guidelines. Such reasonable steps may include periodic audits, issuance of periodic reminders, implementing training classes, discipline of employees as necessary, and other appropriate measures. Steps that a facility commits to take to monitor and assure implementation of the specific guidelines shall be set forth in the written plan and shall be the only elements of Section A-3 and A-5 that constitute enforceable requirements under the written plan, unless other program provisions are independently enforceable pursuant to other requirements of the SOx protocols or District or federal rules or regulations.

B. FREQUENCY OF TESTING

There are three situations which will result in an out-of-control period. These include failure of a calibration error test, failure of a relative accuracy test audit, and failure of a BIAS test, and are detailed in this subdivision. Data collected by a CEMS during an out-of-control period shall not be considered valid.

The frequency at which each quality assurance test must be given is as follows:

1. Periodic Assessments

For each monitor or CEMS, perform the following assessments during each day in which the unit combusts any fuel or processes any material (hereafter referred to as a "unit operating day"), or for a monitor or a CEMS on a bypass stack/duct, during each day that emissions pass through the bypass stack or duct. These requirements are effective as of the date when the monitor or CEMS completes certification testing.

a. Calibration Error Testing Requirements for Pollutant Concentration Monitors, Fuel Gas Sulfur Content Monitors, and O_2 Monitors

Test, record, and compute the calibration error of each SO_2 pollutant concentration monitor, fuel gas sulfur content monitor, if applicable, and O_2 monitor at least once on each unit operating day, or for monitors or monitoring systems on bypass stacks/ducts on each day that emissions pass through the bypass stack or duct. Conduct calibration error checks, to the extent practicable, approximately 24 hours apart. Perform the daily calibration error test according to the procedure in Chapter 2, Subdivision B, Paragraph 1, Subparagraph a, Clause ii of this Attachment.

For units with more than one span range, perform the daily calibration error test on each scale that has been used since the last calibration error test. For example, if the emissions concentration or the fuel gas sulfur content has not exceeded the low-scale span range since the previous calendar day, the calibration error test may be performed on the low-scale only. If, however, the emissions concentration or the fuel gas sulfur content has exceeded the low-scale span range since the previous calibration error test, perform the calibration error test on both the low- and high-scales.

i. Design Requirements for Calibration Error Testing of SO_x Concentration Monitors, the Fuel Gas Sulfur Content Monitors, and O_2 Monitors

Design and equip each SO_x concentration monitor, fuel gas sulfur content monitor, and O_2 monitor with a calibration gas injection port that allows a check of the entire measurement system when calibration gases are introduced. For extractive and dilution type monitors, all monitoring components exposed to the sample gas, (for example, sample lines, filters, scrubbers, conditioners, and as much of the probe as practical) are included in the measurement system. For in situ type monitors, the calibration must check against the injected gas for the performance of all electronic and optical components (for example, transmitter, receiver, analyzer).

Design and equip each pollutant concentration monitor, fuel gas sulfur content and O_2 monitor to allow daily determinations of calibration error (positive or negative) at the zero-level (0 to 20 percent of each span range) and high-level (80 to 100 percent of each span range) concentrations.

ii. Calibration Error Test for SO_x Concentration Monitors, Fuel Gas Sulfur Content Monitors, and O_2 Monitors

Measure the calibration error of each SO_2 concentration analyzer, fuel gas sulfur analyzer, and O_2 monitor once each day according to the following procedures:

If any manual or automatic adjustments to the monitor settings are made, conduct the calibration error test in a way that the magnitude of the adjustments can be determined and recorded.

Perform calibration error tests at two concentrations: (1) zero-level and (2) high level. Zero level is 0 to 20 percent of each span range, and high level is 80 to 100 percent of each span range. All calibration gases used during certification tests and quality assurance and quality control activities shall be NIST/EPA approved standard reference materials (SRM), certified reference materials (CRM), or shall be certified according to "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," September 1997, EPA 600/R-97/121 or any subsequent version published by EPA.

Introduce the calibration gas at the gas injection port as specified above. Operate each monitor in its normal sampling mode. For extractive and dilution type monitors, pass the audit gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling and through as much of the sampling probe as practical. For in situ type monitors, perform calibration checking on all active electronic and optical components, including the transmitter, receiver, and analyzer. Challenge the SO_X concentration monitors, the fuel gas sulfur content monitors, and the O_2 monitors once with each gas. Record the monitor response from the data acquisition and handling system. Use the following equation to determine the calibration error at each concentration once each day:

$$CE = \frac{|R - A|}{S} \times 100 \qquad \text{(Eq. C-1)}$$

Where:

CE = Percentage calibration error based on the span range

R = Reference value of zero- or high-level calibration gas introduced into the monitoring system.

A = Actual monitoring system response to the calibration gas.

S = Span range of the instrument

b. Calibration Error Testing Requirements for Stack Flow Monitors

Test, compute, and record the calibration error of each stack flow monitor at least once within every 14 calendar day period during which at anytime emissions flow through the stack; or for monitors or monitoring systems on bypass stacks or ducts, at least once within every 14 calendar day period during which at anytime emissions flow through the bypass stack or duct. Introduce a zero reference value to the transducer or transmitter. Record flow monitor output from the data acquisition and handling systems before and after any adjustments. Calculate the calibration error using the following equation :

$$CE = \frac{|R - A|}{S} \times 100 \qquad \text{(Eq. C-2)}$$

Where:

CE = Percentage calibration error based on the span range

R = Zero reference value introduced into the transducer or transmitter.

A = Actual monitoring system response.

S = Span range of the flow monitor.

c. Interference Check for Stack Flow Monitors

Perform the daily flow monitor interference checks specified in Chapter 2, Subdivision B, Paragraph 1, Subparagraph c of this Attachment at least once per operating day (when the unit(s) operate for any part of the day).

Design Requirements for Flow Monitor Interference Checks

Design and equip each flow monitor with a means to ensure that the moisture expected to occur at the monitoring location does not interfere with the proper functioning of the flow monitoring system. Design and equip each flow monitor with a means to detect, on at least a daily basis, pluggage of each sample line and sensing port, and malfunction of each resistance temperature detector (RTD), transceiver, or equivalent.

Design and equip each differential pressure flow monitor to provide (1) an automatic, periodic backpurging (simultaneously on both sides of the probe) or equivalent method of sufficient force and frequency to keep the probe and lines sufficiently free of obstructions on at least a daily basis to prevent sensing interference, and (2) a means to detecting leaks in the system at least on a quarterly basis (a manual check is acceptable).

Design and equip each thermal flow monitor with a means to ensure on at least a daily basis that the probe remains sufficiently clean to prevent velocity sensing interference.

Design and equip each ultrasonic flow monitor with a means to ensure on at least a daily basis that the transceivers remain sufficiently clean (for example, backpurging the system) to prevent velocity sensing interference.

d. Recalibration

Adjust the calibration, at a minimum, whenever the calibration error exceeds the limits of the applicable performance specification for the SOx monitor, O_2 monitor or stack flow monitor to meet such specifications. Repeat the calibration error test procedure following the adjustment or repair to demonstrate that the corrective actions were effective. Document the adjustments made.

e. Out-of-Control Period – Calibration Test

An out-of-control period occurs when the calibration error of an SO_2 concentration monitor or a fuel gas sulfur content monitor exceeds 5.0 percent based upon the span range value, when the calibration error of an O_2 monitor exceeds 1.0 percent O_2, or when the calibration error of a flow monitor exceeds 6.0 percent based upon the span range value, which is twice the applicable specification. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour of completion of following an effective recalibration. Whenever the failed calibration, corrective action, and effective recalibration occur within the same hour, the hour is not out-of-control if 2 or more valid readings are obtained during that hour as required by Chapter 2, Subdivision B, Paragraph 5, Subparagraph a.

An out-of-control period also occurs whenever interference of a flow monitor is identified. The out-of-control period begins with the hour of the failed interference check and ends with the hour of completion of an interference check that is passed.

f. Data Recording

Record and tabulate all calibration error test data according to the month, day, clock-hour, and magnitude in ppm, dscfh, and percent volume. Program monitors that automatically adjust data to the calibrated corrected calibration values (for example, microprocessor control) to record either: (1) the unadjusted concentration or flow rate measured in the calibration error test prior to resetting the calibration, or (2) the magnitude of any adjustment. Record the following applicable flow monitor interference check data: (1) sample line/sensing port pluggage, and (2) malfunction of each RTD, transceiver, or equivalent.

2. Semi-annual Assessments

a. For each CEMS, perform the following assessments once semi-annually thereafter, as specified below for the type of test. These semi-annual assessments shall be completed within six months of the end of the calendar quarter in which the CEMS was last tested for certification purposes (initial and recertification) or within three months of the end of the calendar quarter in which the District sent notice of a provisional approval for a CEMS, whichever is later. Thereafter, the semi-annual tests shall be completed within six months of the end of the calendar quarter in which the CEMS was last tested. For CEMS on bypass stacks/ducts, the assessments shall be performed once every two successive operating quarters in which the bypass stacks/ducts were operated. These tests shall be performed after the calendar quarter in which the CEMS was last tested as part of the CEMS certification, as specified below for the type of test.

Relative accuracy tests may be performed on an annual basis rather than on a semi-annual basis if the relative accuracies during the previous audit for the SO_X pollutant concentration monitor, flow monitoring system, and SOx emission rate measurement system are 7.5 percent or less.

b. For CEMS on any stack or duct through which no emissions have passed in two or more successive quarters, the semi-annual assessments must be performed within 14 unit operating days after emissions pass through the stack/duct.

c. The due date for a semi-annual or annual assessment of a major source may be postponed to within 14 unit operating days from the first re-firing of the major source if the major source is physically incapable of being operated and all of the following are met:

i. All fuel feed lines to the major source are either disconnected or opened and either flanges or equivalent sealing devices are placed at both ends of the disconnected or opened lines, and

ii. The fuel meter(s) for the disconnected fuel or opened feed lines are maintained and operated and associated fuel records showing no fuel flow are maintained on site.

This paragraph applies separately for each unrelated, independent event. For any hour that fuel flow records are not available to verify no fuel flow, SOx emissions shall be calculated using the maximum valid hourly emissions from the last 30 days of operation.

Prior to re-starting operation of the major source, the Facility Permit Holder shall: (1) provide written notification to the District no later than 72 hours prior to starting up the source, (2) start the CEMS no later than 24 hours prior to the start-up of the major source, and (3) conduct and pass a Cylinder Gas Analysis (CGA) prior to the start-up of the major source. The emissions data from the CEMS after the re-start of operations is considered valid only if the Facility Permit Holder passes the CGA test. Otherwise, for a non-passing CGA, the CEMS data is considered invalid until the semi-annual or annual assessment is performed and passed. As such, SOx emissions shall be calculated using the maximum valid hourly emissions from the last 30 days of operation commencing with the hour of start up and continuing through the hour prior to performing and passing the semi-annual or annual assessment.

d. An electrical generating facility that either only operates under a California Independent System Operator (Cal ISO) contract or is owned and operated by a municipality may postpone the due date for a semi-annual or annual assessment of a major source to the next calendar quarter provided that the facility shows:

i. The semi-annual or annual assessment was scheduled to be performed during the first 45 days of the calendar quarter in which the assessment was due;

ii. The assessment was not completed due to lack of adequate operational time; and

iii. A CGA was conducted and passed within the calendar quarter when the assessment was due.

e. Relative Accuracy Test Audit

Perform relative accuracy test audits and bias tests semi-annually and no less than 3 months apart for each SO_2 pollutant concentration monitor, fuel gas sulfur content monitor, stack gas volumetric flow rate measurement systems, and the SO_2 mass emission rate measurement system in accordance with Chapter 2, Subdivision B, Paragraphs 10, 11, 12, and 13 and Attachment B of the Protocol for Rule 2011. The relative accuracy of the pollutant concentration monitor and the mass emission rate measurement system shall be less than or equal to 20.0 percent, and the relative accuracy of the stack gas volumetric flow rate measurement system shall be less than or equal to 15.0 percent. For monitors on bypass stacks/ducts, perform relative accuracy test audits once every two successive bypass operating quarters in accordance with Chapter 2, Subdivision B, Paragraphs 10, 11, 12, and 13 and Attachment B (bias test) of the Protocol for Rule 2011.

f. Out-of-Control Period – Relative Accuracy Test Audit

An out-of-control period occurs under any of the following conditions: (1) The relative accuracy of an SO_2 pollutant concentration monitor, a fuel gas sulfur content monitor, or the SO_2 emission rate measurement system exceeds 20.0 percent; (2) the relative accuracy of the flow rate monitor exceeds 15.0 percent; or (3) failure to conduct a relative accuracy test audit by the due date for a semi-annual assessment. The out-of-control period begins with the hour of completion of the failed relative accuracy test audit and ends with the hour of completion of a satisfactory relative accuracy test audit.

g. Out-of-Control Period – BIAS Test

An out-of-control period occurs if all the following conditions are met:

i. Failure of a bias test as specified in Attachment B of this Appendix;

ii. The CEMS is biased low relative to the reference method (i.e. Bias Adjustment Factor (BAF), as determined in Attachment B of this Appendix, is greater than 1); and

iii. The Facility Permit holder does not apply the BAF to the CEMS data.

The out-of-control period begins with the hour of completion of the failed bias test audit and ends with the hour of completion of a satisfactory bias test.

h. Alternative Relative Accuracy Test Audit

i. The Facility Permit holder of a major source, that has received written approval from the Executive Officer as an intermittently operated source, may postpone the due date for a semi-annual assessment to the end of the next calendar quarter if the Facility Permit holder:

I. operated the source no more than 240 cumulative operating hours and no more than 72 consecutive hours during the calendar quarter when a semi-annual assessment is due; and

II. conducted a relative accuracy test audit on the CEMS serving the source during the previous four calendar quarters and meeting the accuracy criteria as set forth under Subparagraph B.2.e.; and

III. conducted an alterative relative accuracy test audit on the CEMS serving the source during the calendar quarter when a semi-annual assessment is due and meeting the criteria specified under Clause B.2.h.iii.

If any of the requirements under Subclauses B.2.h.i.I, II and III is not met and the source did not have passing RATA during the calendar quarter when the semi-annual assessment is due, emissions from the source shall be determined pursuant to the Missing Data Procedures as specified under Rule 2011, Appendix A, Chapter 2, Subdivision E after the semi-annual assessment due date until the hour of completion of a satisfactory relative accuracy test audit.

ii. The Facility Permit holder may submit a written request to designate a major source as an intermittently operated source provided the Facility Permit holder demonstrates that:

I. During any calendar quarter within the previous two compliance years, the source was operated no more than 240 cumulative operating hours and no more than 72 consecutive hours ; or

II. During any calendar quarter within the next two compliance years, the source will be operated no more than 240 cumulative operating hours and no more than 72 consecutive hours.

iii. An alternative relative accuracy shall consist of a Cylinder Gas Analysis (CGA) method as defined under 40 CFR, Part 60, Appendix F, combined with a flow accuracy verification. For sources equipped with stack flow monitors, the flow accuracy shall be verified by calibrating the transducers and transmitters installed on the stack flow monitors using procedures under Paragraph B.3 of this attachment. For sources equipped with fuel flow meters and no stack flow monitors, the flow accuracy shall be verified by calibrating the fuel flow meters either in-line or offline in accordance with the procedures outlined in 40CFR Part 75, Appendix D. Passing flow accuracy verification results that were obtained within the past 4 quarters may be used in lieu of performing a flow accuracy verification during the calendar quarter when a semi-annual assessment is due. The calculated accuracy for the analyzer responses for NO_x and O_2 concentration shall be within 15 percent or 1 ppm, whichever is greater, as determined by the CGA method as defined under 40 CFR, Part 60, Appendix F. Successive alternative relative accuracy test audits shall be performed no less than 45 days apart.

3. Calibration of Transducers and Transmitters on Stack Flow Monitors

All transducers and transmitters installed on stack flow monitors must be calibrated every two operating calendar quarters, in which an operating calendar quarter is any calendar quarter during which at anytime emissions flow through the stack. Calibration must be done in accordance with Executive Officer approved calibration procedures that employ materials and equipment that are NIST traceable.

When a calibration produces for a transducer and transmitter a percentage accuracy of greater than ± 1%, the Facility Permit holder shall calibrate the transducer and transmitter every calendar operating quarter until a subsequent calibration which shows a percentage accuracy of less than ± 1% is achieved. An out-of-control period occurs when the percentage accuracy exceeds ±2%. If an out-of-control period occurs, the Facility Permit holder shall take corrective measures to obtain a percentage accuracy of less than ±2% prior to performing the next RATA. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour of completion of following an effective recalibration. Whenever the failed calibration, corrective action, and effective recalibration occur within the same hour, the hour is not out-of-control if two or more valid data readings are obtained during that hour as required by Chapter 2, Subdivision B, Paragraph 5, Subparagraph a.

RULE 2011 PROTOCOL
ATTACHMENT D

LIST OF ACRONYMS AND ABBREVIATIONS

LIST OF ACRONYMS AND ABBREVIATIONS

APEP	Annual Permit Emission Program
API	American Petroleum Institute
ASTM	American Society for Testing & Materials
BACT	Best Available Control Technology
bhp	Brake Horsepower
bpd	Barrels per Day
Btu	British Thermal Unit
CEMS	Continuous Emission Monitoring System
CPMS	Continuous Process Monitoring System
CPU	Central Processing Unit
CSCACS	Central Station Compliance Advisory Computer System
DAS	Data Acquisition System
DM	District Method
dscfh	Dry Standard Cubic Feet per Hour
FCCU	Fluid Catalytic Cracking Unit
F_d	Dry F Factor
FGR	Flue Gas Recirculation
gpm	Gallons per Minute
ICE	Internal Combustion Engine
ID	Inside Diameter
ISO	International Standards Organization
lbmole	Pound mole
LNB	Low NO_x Burner
MRR	Monitoring, Reporting and Recordkeeping
NIST	National Institute of Standards for Testing
NO_x	Oxides of Nitrogen
NSCR	Non-Selective Catalytic Reduction
O_2	Oxygen
ppmv	Parts per Million Volume
ppmw	Parts per Million by Weight
RAA	Relative Accuracy Audit
RATA	Relative Accuracy Test Audit
RECLAIM	Regional Clean Air Incentives Market

RM	Reference Method
RTC	RECLAIM Trading Credits
RTCC	Real Time Calendar/Clock
RTU	Remote Terminal Unit
scfh	Standard Cubic Feet per Hour
scfm	Standard Cubic Feet per Minute
SCR	Selective Catalytic Reduction
SDD	Software Design Description
SNCR	Selective Non-Catalytic Reduction
SO_x	Oxides of Sulfur
SRG	Software/Hardware Requirement Guideline
swi	Steam Water Injection
tpd	Tons per day
tpy	Tons per year
WAN	Wide Area Network

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3/17/17

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

RULE 2011 PROTOCOL- ATTACHMENT E

DEFINITIONS

DEFINITIONS

(1) AFTERBURNERS, also called VAPOR INCINERATORS, are air pollution control devices in which combustion converts the combustible materials in gaseous effluents to carbon dioxide and water.

(2) ALTERNATIVE EMISSION FACTOR is a SOx emission value expressed in units of pounds per million standard cubic feet or pounds per thousand gallons derived using the methodology specified in Appendix A, Protocols for Monitoring, Reporting, and Recordkeeping for Oxides of Sulfur (SOx) Emissions, Chapters 3 and 4.

(3) ANNUAL PERMIT EMISSIONS PROGRAM (APEP) is the annual facility permit compliance reporting, review, and fee reporting program.

(4) BOILER is any combustion equipment used to produce steam, including a carbon monoxide boiler. This does not include a process heater that transfers heat from combustion gases to process streams, a waste heat recovery boiler that is used to recover sensible heat from the exhaust of process equipment such as a combustion turbine, or a recovery furnace that is used to recover process chemicals. Boilers used primarily for residential space and/or water heating are not affected by this section.

(5) BURN means to combust any gaseous fuel, whether for useful heat or by incineration without recovery, except for flaring or emergency vent gases.

(6) BYPASS OPERATING QUARTER means each calendar quarter that emissions pass through the bypass stack or duct.

(7) CALCINER is a rotary kiln where calcination reaction is carried out between 1315 ^{o}C to 1480 ^{o}C.

(8) CEMENT KILN is a device for the calcining and clinkering of limestone, clay and other raw materials, and recycle dust in the dry-process manufacture of cement.

(9) CONTINUOUS EMISSIONS MONITORING SYSTEM (CEMS) is the total equipment required for the determination of concentrations of air contaminants and diluent gases in a source effluent as well as mass emission rate. The system consists of the following three major subsystems:

(A) SAMPLING INTERFACE is that portion of the monitoring system that performs one or more of the following operations: extraction, physical/chemical separation, transportation, and conditioning of a sample of the source effluent or protection of the analyzer from the hostile aspects of the sample or source environment.

(B) ANALYZERS

(i) AIR CONTAMINANT ANALYZER is that portion of the monitoring system that senses the air contaminant and generates a signal output which is a function of the concentration of that contaminant.

(ii) DILUENT ANALYZER is that portion of the monitoring system that senses the concentration of oxygen or carbon dioxide or other diluent gas as applicable, and generates a signal output which is a function of a concentration of that diluent gas.

(C) DATA RECORDER is that portion of the monitoring system that provides a permanent record of the output signals in terms of concentration units, and includes additional equipment such as a computer required to convert the original recorded value to any value required for reporting.

(10) CONTINUOUS PROCESS MONITORING SYSTEM is the total equipment required for the measurement and collection of process variables (e.g., fuel usage rate, oxygen content of stack gas, or process weight). Such CPMS data shall be used in conjunction with the appropriate fuel sulfur limit or fuel sulfur content to determine SOx emissions.

(11) CONTINUOUSLY MEASURE means to measure at least once every 15 minutes except during period of routine maintenance and calibration as specified in 40 CFR Part 60.13(e)(2).

(12) DAILY means a calendar day starting at 12 midnight and continuing through to the following 12 midnight hour.

(13) DIRECT MONITORING DEVICE is a device that directly measures the variables specified by the Executive Officer to be necessary to determine mass emissions of a RECLAIM pollutant and which meets all the standards of performance for CEMS set forth in the protocols for NOx and SOx.

(14) DRYER is equipment that removes substances by heating or other processes.

(15) ELECTRONICALLY TRANSMITTING means transmitting measured data without human alteration between the point/source of measurement and transmission.

(16) EMISSION FACTOR is the value specified in Tables 1 (NOx) or 2 (SOx) of Rule 2002-Baselines and Rates of Reduction for NOx and SOx.

(17) EXISTING EQUIPMENT is any equipment which can emit SOx at a SOx RECLAIM facility, for which on or before (Rule Adoption date) has:

(A) A valid permit to construct or permit to operate pursuant to Rule 201 and/or Rule 203 has been issued; or

(B) An application for a permit to construct or permit to operate has been deemed complete by the Executive Officer; or

(C) An equipment which is exempt from permit per Rule 219 and is operating on or before (Rule Adoption date).

(18) F_d FACTOR is the dry F factor for each fuel, the ratio of the dry gas volume of the products of combustion to the heat content of the fuel (dscf/10^6 Btu).

(19) GAS FLARE is a combustion equipment used to prevent unsafe operating pressures in process units during shut downs and start-ups and to handle miscellaneous hydrocarbon leaks and process upsets.

(20) FLUID CATALYTIC CRACKING UNIT (FCCU) breaks down heavy petroleum products into lighter products using heat in the presence of finely divided catalyst maintained in a fluidized state by the oil vapors. The fluid catalyst is continuously circulated between the reactor and the regenerator, using air, oil vapor, and steam as the conveying media.

(21) FURNACE is an enclosure in which energy in a nonthermal form is converted to heat.

(22) GAS TURBINES are turbines that use gas as the working fluid. It is principally used to propel jet aircraft. Their stationary uses include electric power generation (usually for peak-load demands), end-of-line voltage booster service for long distance transmission lines, and for pumping natural gas through long distance pipelines. Gas turbines are used in combined (cogeneration) and simple-cycle arrangements.

(23) GASEOUS FUELS include, but are not limited to, any natural, process, synthetic, landfill, sewage digester, or waste gases with a gross heating value of 300 Btu per cubic foot or higher, at standard conditions.

(24) HEAT VALUE is the heat generated when one lb. of combustible is completely burned.

(25) HEATER is any combustion equipment fired with liquid and/or gaseous fuel and which transfers heat from combustion gases to water or process streams.

(26) HIGH HEAT VALUE is determined experimentally by colorimeters in which the products of combustion are cooled to the initial temperature and the heat absorbed by the cooling media is measured.

(27) HOT STAND BY is the period of operation when the flow or emission concentrations are so low they can not be measured in a representative manner.

(28) INCINERATOR is equipment that consumes substances by burning.

(29) INTERNAL COMBUSTION ENGINE is any spark or compression-ignited internal combustion engine, not including engines used for self-propulsion.

(30) LIQUID FUELS include, but are not limited to, any petroleum distillates or fuels in liquid form derived from fossil materials or agricultural products for the purpose of creating useful heat.

(31) MASS EMISSION OF SOx in lbs/hr is the measured emission rates of sulfur oxides.

(32) MAXIMUM RATED CAPACITY means maximum design heat input in Btu per hour at the higher heating value of the fuels.

(33) MODEM converts digital signals into audio tones to be transmitted over telephone lines and also convert audio tones from the lines to digital signals for machine use.

(34) MONTHLY FUEL USE REPORTS could be sufficed by the monthly gas bill or the difference between the end and the beginning of the calendar month's fuel meter readings.

(35) NINETIETH (90th) PERCENTILE means a value that would divide an ordered set of increasing values so that at least 90 percent are less than or equal to the value and at least 10 percent are greater than or equal to the value

(36) OVEN is a chamber or enclosed compartment equipped to heat objects.

(37) PEAKING UNIT means a turbine used intermittently to produce energy on a demand basis and does not operate more than 1300 hours per year.

(38) PORTABLE EQUIPMENT is an equipment which is not attached to a foundation and is not operated at a single facility for more than 90 consecutive days in a year and is not a replacement equipment for a specific application which lasts or is intended to last for more than one year.

(39) PROCESS HEATER means any combustion equipment fired with liquid and/or gaseous fuel and which transfers heat from combustion gases to process streams.

(40) PROCESS WEIGHT means the total weight of all materials introduced into any specific process which may discharge contaminants into the atmosphere. Solid fuels charged shall be considered as part of the process weight, but liquid gaseous fuels and air shall not.

(41) RATED BRAKE HORSEPOWER (bhp) is the maximum rating specified by the manufacturer and listed on the nameplate of that equipment.

(42) RATED HEAT INPUT CAPACITY is the heat input capacity specified on the nameplate of the combustion unit. If the combustion unit has been altered or modified such that its maximum heat input is different than the heat input capacity specified on the nameplate, the new maximum heat input shall be considered as the rated heat input capacity.

(43) RECLAIM FACILITY is a facility that has been listed as a participant in the Regional Clean Air Incentives Market (RECLAIM) program.

(44) REMOTE TERMINAL UNIT (RTU) is a data collection and transmitting device used to transmit data and calculated results to the District Central Station Computer.

(45) RENTAL EQUIPMENT is equipment which is rented or leased for operation by someone other than the owner of the equipment

(46) SHUTDOWN is that period of time during which the equipment is allowed to cool from a normal operating temperature range to a cold or ambient temperature.

(47) SOLID FUELS include, but are not limited to, any solid organic material used as fuel for the purpose of creating useful heat.

(48) STANDARD GAS CONDITIONS are defined as one atmosphere of pressure and a temperature of 68 ^{O}F or 60 ^{O}F, provided that one of these temperatures is used throughout the facility.

(49) START-UP is that period of time during which the equipment is heated to operating temperature from a cold or ambient temperature.

(50) SULFURIC ACID PRODUCTION UNIT means any facility producing sulfuric acid by the contact process by burning elemental sulfur, alkylation acid, hydrogen sulfide, organic sulfides and mercaptans or acid sludge, but does not include facilities where conversion to sulfuric acid is utilized primarily as a means of preventing emissions to the atmosphere of sulfur dioxide or other sulfur compounds.

(51) TAIL GAS UNIT is a SOx control equipment associated with refinery sulfur recovery plant.

(52) TEST CELLS are devices used to test the performance of engines such as internal combustion engine and jet engines.

(53) TIMESHARING OF MONITOR means the use of a common monitor for several sources of emissions.

(54) TURBINES are machines that convert energy stored in a fluid into mechanical energy by channeling the fluid through a system of stationary and moving vanes.

(55) UNIT OPERATING DAY means each calendar day that emissions pass through the stack or duct.

(56) UNIVERSE OF SOURCES FOR NOx is a list of RECLAIM facilities that emit NOx.

(57) UNIVERSE OF SOURCES FOR SOx is a list of RECLAIM facilities that emit SOx.

(58) AP 42 is a publication published by Environmental Protection Agency (EPA) which is a compilation of air pollution emission rates used to determine mass emission.

(59) ASTM METHOD D1945-81 Method for Analysis of natural gas by gas chromatography.

(60) ASTM METHOD 2622-82 Test Method for sulfur in petroleum products (Xray Spectrographic method)

(61) ASTM METHOD 3588-91 method for calculating colorific value and specific gravity (relative density) of gaseous fuels.

(62) ASTM METHOD 4294-90 test method for sulfur in petroleum products by non-dispersive Xray fluorescence spectrometry.

(63) ASTM METHOD 4891-84 test method for heating value of gases in natural gas range by stoichiometric combustion.

(64) DISTRICT METHOD 2.1 measures gas flow rate through stacks greater than 12 inch in diameter.

(65) DISTRICT METHOD 7.1 colorimetric determination of nitrogen oxides except nitrous oxide emissions from stationary sources by using the phenoldisulfonic acid (pds) procedure or ion chromatograph procedures. Its range is 2 to 400 milligrams NOx (as NO_2 per DSCM).

(66) DISTRICT METHOD 100.1 is an instrumental method for measuring gaseous emissions of nitrogen oxides, sulfur dioxide, carbon monoxide, carbon dioxide, and oxygen.

(67) DISTRICT METHOD 307-91 laboratory procedure for analyzing total reduced sulfur compounds and SO_2.

(68) EPA METHOD 19 is the method of determining sulfur dioxide removal efficiency and particulate, sulfur dioxide and nitrogen oxides emission rates from electric utility steam generators.

(69) EPA METHOD 450/3-78-117 air pollutant emission rate for Military and Civil Aircraft.

RULE 2011 PROTOCOL- ATTACHMENT F

SUPPLEMENTAL AND ALTERNATIVE CEMS PERFORMANCE REQUIREMENTS FOR LOW SOx CONCENTRATIONS

ATTACHMENT F

SUPPLEMENTAL AND ALTERNATIVE CEMS PERFORMANCE REQUIREMENTS FOR LOW SOx CONCENTRATIONS

Abbreviations used in this Attachment are:
√ Low Level Spike Recovery/Bias Factor Determination (LLSR/BFD)
√ High Level Spike Recovery/Bias Factor Determination (HLSR/BFD)
√ Low Level RATA/Bias Factor Determination (LLR/BFD)
√ Low Level Calibration Error (LLCE)
√ Relative Accuracy Test Audit (RATA)
√ Relative Accuracy (RA)
√ Full Scale Span (FSS)
√ National Institute of Standards Traceability (NIST)

A. Applicability of Supplemental and Alternative Performance Requirements

The Facility Permit holder electing to use (B)(8)(d)(ii), in Chapter 2 of Rule 2011, Appendix A to measure SO_X concentrations that fall below 10 percent of the lowest vendor guaranteed full scale span range, shall satisfy the performance requirements as specified in Table F-1 listed below.

TABLE F-1
Alternative Performance Requirement(s)

CEMS RECLAIM Certified per SOx Protocol, Appendix A	**Performance Requirements**			
Yes or No	LLSR/BFD	HLSR/BFD	LLR/BFD	LLCE
Yes	×		+	×
No	×	×	+	×

1. + (plus) denotes an additional performance requirement that shall be conducted if the mandatory performance requirement(s) cannot be met.

2. If the concentration of the CEMS is such that the specifications for the low level spike recovery/bias factor determination cannot be met, the Facility Permit holder shall conduct a low level RATA/bias factor determination.

3. The provisions of Table F-1 do not apply to (B)(8)(c) or (B)(8)(d)(i), in Chapter 2.

B. Test Definitions, Performance Specifications and Test Procedures

This section explains in detail how each performance requirement is to be conducted.

Low Level Calibration Error

The low level calibration error test is defined as challenging the CEMS (from probe to monitor) with certified calibration gases at three levels in the 0-20 percent full scale span range. Since stable or certifiable cylinder gas standards (e.g. Protocol 1 or NIST traceable) may not be available at the concentrations required for this test, gas dilution systems may be used, with District approval, if they are used according to either District or EPA protocols for the verification of gas dilution systems in the field. The CEMS high level calibration gas may be diluted for the purpose of conducting the low level calibration error test.

1. Performance Specifications

Introduce pollutant concentrations at approximately the 20 percent, 10 percent, and 5 percent of full scale span levels through the normal CEMS calibration system. No low level calibration error shall exceed 2.5 percent of full scale span.

2. Testing Procedures

   a. Perform a standard zero/span check; if zero or span check exceeds 2.5 percent full scale span, adjust monitor and redo zero/span check.

   b. After zero/span check allow the CEMS to sample stack gas for at least 15 minutes.

   c. Introduce any of the low level calibration error standards through the CEMS calibration system.

   d. Read the CEMS response to the calibration gas starting no later than three system response times after introducing the calibration gas; the CEMS response shall be averaged for at least three response times and for no longer than six response times.

   e. After the low level calibration error check allow the CEMS to sample stack gas for at least 15 minutes.

f. Repeat steps c through e until all three low level calibration error checks are complete.

g. Conduct post test calibration and zero checks.

Spike Recovery and Bias Factor Determinati1ons

Spiking is defined as introducing know concentrations of the pollutant of interest and an appropriate non-reactive, non-condensable and non-soluble tracer gas from a single cylinder (Protocol 1 or NIST traceable if no Protocol 1 is available) near the probe and upstream of any sample conditioning systems, at a flow rate not to exceed 10 percent of the total sample gas flow rate. The purpose of the 10 percent limitation is to ensure that the gas matrix (water, CO2, particulates, interferences) is essentially the same as the stack gas alone. The tracer gas is monitored in real time and the ratio of the monitored concentration to the certified concentration in the cylinder is the dilution factor. The expected pollutant concentration (dilution factor times the certified pollutant concentration in the cylinder) is compared to the monitored pollutant concentration.

High Level Spike Recovery/Bias Factor Determination

The high level spike recovery/bias factor determination is used when the CEMS has not been certified per the standard RECLAIM requirements. The spiking facility/interface shall be a permanently installed part of the CEMS sample acquisition system and accessible to District staff as well as the Facility Permit holder.

1. Performance Specifications

   The CEMS shall demonstrate a RA </= 20 percent, where the spike value is used in place of the reference method in the normal RA calculation, as described below. The bias factor, if applicable, shall also be determined according to Attachment B.

2. Testing Procedures

   a. Spike the sample to the CEMS with a calibration standard containing the pollutant of interest and CO or other non-soluble, non-reacting alternative tracer gas (alternative tracer gas) at a flow rate not to exceed 10 percent of the CEMS sampling flow rate and of such concentrations as to produce an expected 40-80 percent of full scale span for the pollutant of interest and a quantifiable concentration of CO (or alternative tracer gas) that is at least a factor of 10 higher than expected in the unspiked stack gas. The calibration standards for both pollutant of interest and CO (or alternative tracer gas) must meet RECLAIM requirements specified in Attachment A.

b. Monitor the CO (or alternative tracer gas) using an appropriate continuous (or semi-continuous if necessary) monitor meeting the requirements of Method 100.1 and all data falling within the 10-95 percent full scale span, and preferably within 30-70 percent full scale span.

c. Alternate spiked sample gas and unspiked sample gas for a total of nine runs of spiked sample gas and ten runs of unspiked sample gas. Sampling times should be sufficiently long to mitigate response time and averaging effects.

d. For each run, the average CEMS reading must be between 40 percent full scale span and 80 percent full scale span. If not, adjust spiking as necessary and continue runs; but expected spike must represent at least 50 percent of the total pollutant value read by the CEMS.

e. Calculate the spike recovery for both the pollutant and the CO (or alternative tracer gas) for each run by first averaging the pre- and post-spike values for each run and subtracting that value from the spiked value to yield nine values for recovered spikes.

f. Using the CO (or alternative tracer gas) spike recovery values for each run and the certified CO (or alternative tracer gas) concentration, calculate the dilution ratio for each run. Multiply the certified pollutant concentration by the dilution factor for each run to determine the expected diluted pollutant concentrations. Using the expected diluted concentrations as the "reference method" value calculate the Relative Accuracy as specified in Appendix A. The RA shall be </= 20 percent. Determine the bias factor, if applicable, according to Attachment B.

Low Level Spike Recovery/Bias Factor Determination

The low level spike recovery/bias factor determination is used to determine if a significant bias exists at concentrations near the 10 percent full scale span level. The spiking facility/interface shall be a permanently installed part of the CEMS sample acquisition system and accessible to District staff as well as the Facility Permit holder.

1. Performance Specifications

   There are no pass/fail criteria with respect to the magnitude of the percent relative accuracy. There are performance criteria for the range of concentration on the CEMS and the extent to which the spike must be greater than the background pollutant level.

2. Testing Procedures

   a. Spike the sample to the CEMS with a calibration standard containing the pollutant of interest and CO or other non-soluble, non-reacting alternative tracer gas (alternative tracer gas) at a flow rate not to exceed 10 percent of the CEMS sampling flow rate and of such concentrations as to produce an expected 10-25 percent of full scale span for the pollutant of interest and a quantifiable concentration of CO (or alternative tracer gas) that is at least a factor of 10 higher than expected in the unspiked stack gas. The calibration standards for both pollutant of interest and CO (or alternative tracer gas) must meet RECLAIM requirements specified in Appendix A.

   b. Monitor the CO (or alternative tracer gas) using an appropriate continuous (or semi-continuous if necessary) monitor meeting the requirements of Method 100.1 and all data falling within the 10-95 percent full scale span, and preferably within 30-70 percent full scale span.

   c. Alternate spiked sample gas and unspiked sample gas for a total of nine runs of spiked sample gas and ten runs of unspiked sample gas. Sampling times should be sufficiently long to mitigate response time and averaging effects.

d. For each run, the average CEMS reading must be below 25 percent full scale span and > 10 percent full scale span. If not, adjust spiking as necessary and continue runs; but expected spike must represent at least 50 percent of the total pollutant value read by the CEMS.

e. Calculate the spike recovery for both the pollutant and the CO (or alternative tracer gas) for each run by first averaging the pre- and post-spike values for each run and subtracting that value from the spiked value to yield nine values for recovered spikes.

f. Using the CO (or alternative tracer gas) spike recovery values for each run and the certified CO (or alternative tracer gas) concentration, .calculate the dilution ratio for each run. Multiply the certified pollutant concentration by the dilution factor for each run to determine the expected diluted pollutant concentrations. Using the expected diluted concentrations as the "reference method" value calculate the Relative Accuracy as specified in Appendix A. If the average difference is less than the confidence coefficient then no low level bias factor is applied. If the average difference is greater than the confidence coefficient and the average expected spike is less than the average CEMS measured spike, then no low level bias factor is applied. If the average difference is greater than the confidence coefficient and the average expected spike is greater than the average CEMS measured spike, then a low level bias factor equal to the absolute value of the average difference is added to data reported at or below the 10 percent of full scale span.

Low Level RATA/Bias Factor Determination using Enhanced Reference Method 6.1

A low level RATA/bias factor determination is designed to determine if there exists a statistically significant bias at low level concentrations. It consists of nine test runs that measure the stack concentration and the CEMS concentration concurrently.

1. Performance Specifications

There are no pass/fail criteria with respect to the magnitude of the percent relative accuracy. There are performance criteria for the special RATA with respect to the reference method and range of concentration on the CEMS.

2. Testing Procedures

The reference method for the low level RATA/bias factor determination is Method 100.1

a. Perform a minimum of nine runs of low level RATA for CEMS versus the reference method at actual levels (unspiked).

b. The full scale span range for the reference method shall be such that all data falls with 10 - 95 percent of full scale span range.

c. The reference method shall meet all Method 100.1 performance criteria.

d. Calculate the average difference (d = CEMS - reference method, ppm) and confidence coefficient (cc = statistical calculated, ppm).

e. If d > 0 then the bias = 0 ppm; if d < 0 and |d| > cc then bias = d; if d < 0 and |d| < cc then bias = 0 ppm.

C. Testing Frequency

For each CEMS, perform the aforementioned performance requirements once semiannually thereafter, as specified below for the type of test. These semiannual assessments shall be completed within six months of the end of the calendar quarter in which the CEMS was last tested for certification purposes (initial and recertification) or within three months of the end of the calendar quarter in which the District sent notice of a provisional approval for a CEMS, whichever is later. Thereafter, the semiannual tests shall be completed within six months of the end of the calendar quarter in which the CEMS was last tested. For CEMS on bypass stacks/ducts, the assessments shall be performed once every two successive operating quarters in which the bypass stacks/ducts were operated. These tests shall be performed after the calendar quarter in which the CEMS was last tested as part of the CEMS certification, as specified below for the type of test.

Relative accuracy tests may be performed on an annual basis rather than on a semiannual basis if the relative accuracies during the previous audit for the SO_X CEMS are 7.5 percent or less.

For CEMS on any stack or duct through which no emissions have passed in two or more successive quarters, the semiannual assessments must be performed within 14 operating days after emissions pass through the stack/duct.

(Adopted October 15, 1993) (Amended March 10, 1995)(Amended September 8, 1995)
(Amended December 7, 1995)(Amended July 12, 1996)(Amended February 14, 1997)
(Amended April 11, 1997)(Amended April 9, 1999)(Amended March 16, 2001)
(Amended May 11, 2001)(Amended December 5, 2003)(Amended January 7, 2005)

RULE 2012. REQUIREMENTS FOR MONITORING, REPORTING, AND RECORDKEEPING FOR OXIDES OF NITROGEN (NO_X) EMISSIONS

(a) Purpose

The purpose of this rule is to establish the monitoring, reporting and recordkeeping requirements for NO_X emissions under the RECLAIM program.

(b) Applicability

The provisions of this rule shall apply to any RECLAIM NO_X source or NO_X process unit. The NO_X sources and process units regulated by this rule include, but are not limited to:

Boilers	Fluid Catalytic Cracking Units
Internal Combustion Engines	Dryers
Heaters	Fume Incinerators/Afterburners
Gas Turbines	Test Cells
Furnaces	Tail Gas Units
Kilns and Calciners	Sulfuric Acid Production
Ovens	Waste Incinerators

(c) Major NO_X Source

(1) Major NO_X Source means any of the following NO_X sources, except for such NO_X sources reclassified as large NOx sources at approved Super Compliant Facilities as specified in paragraph (c)(4):

(A) any boiler, furnace, oven, dryer, heater, incinerator, test cell and any solid, liquid or gaseous fueled equipment with a maximum rated capacity:

(i) greater than or equal to 40 but less than 500 million Btu per hour and an annual heat input greater than 90 billion Btu per year; or

(ii) 500 million Btu per hour or more irrespective of annual heat input;

(B) any internal combustion engine with rated brake horsepower (bhp) greater than or equal to 1,000 bhp and operating more than 2,190 hours per year;

(C) any gas turbine rated greater than or equal to 2.9 megawatts excluding any emergency standby equipment or peaking unit;

(D) any petroleum refinery fluid catalytic cracking unit;

(E) any petroleum refinery tail gas unit;

(F) any kiln or calciner with a rated process weight greater than or equal to 10 tons per hour and processing more than 21,900 tons per year, except brick kilns;

(G) any equipment burning or incinerating solid fuels or materials;

(H) any existing equipment using NO_X CEMS or that is required to install CEMS under District rules to be implemented as of October 15, 1993;

(I) any NO_X source or process unit elected by the Facility Permit holder or required by the Executive Officer or designee to be monitored and to report emissions with a CEMS meeting the requirements of paragraphs (c)(2) and (c)(3);

(J) any NO_X source or process unit for which NO_X emissions reported pursuant to Rule 301 - Permit Fees, were equal to or greater than 10 tons per year for any calendar year between 1987 to 1991, inclusive, excluding NO_X sources or process units listed under subparagraphs (d)(1)(A) through (d)(1)(E), and (e)(1)(A) through (e)(1)(D) and excluding any NO_X source or process unit which has reduced NO_X emissions to below 10 tons per year prior to January 1, 1994.

(2) The Facility Permit holder of a major NO_X source shall:

(A) install, maintain and operate a direct monitoring device for each major NO_X source to continuously measure the concentration of NO_X emissions and all other applicable variables specified in Table 2012-1 and Appendix A, Chapter 2, Table 2-A; or

(B) install, maintain, and operate an alternative monitoring device which has been determined by the Executive Officer or designee to be equivalent to CEMS in relative accuracy, reliability, reproducibility and timeliness according to the requirements set forth in Appendix A, Chapter 2.

(C) The operating requirements specified in subparagraph (c)(2)(A) or (c)(2)(B) shall not apply during any time period not to exceed 96 hours provided that all of the following are met:

(i) the Facility Permit holder reports emissions as specified in Appendix A;

(ii) the direct monitoring device has been either:

(I) shut down for maintenance performed pursuant to the facility's Quality Assurance and Quality Control Program or

(II) damaged in a fire or mechanical or electrical failure caused by circumstances beyond the Facility Permit holder's control; and

(iii) Whenever the monitoring device is non-operational for more than 24 hours, the Facility Permit holder shall submit a report to the Executive Officer within 96 hours after the device becomes non-operational. Such report shall include information as prescribed by the Executive Officer including at a minimum the cause of the shutdown, the time the monitoring device became non-operational, the time or estimated time the monitoring device returned to normal operation, and the maintenance performed or corrective and preventative actions taken to prevent future non-operational conditions.

If the source for which the CEMS is certified to monitor is not operating when the CEMS is in maintenance or being repaired, and either the flow or concentration monitor is properly operating, and clauses (c)(2)(C)(i) and (c)(2)(C)(ii) are met, then the above time period shall be extended for an additional 96 hours.

(3) The Facility Permit holder of a major NO_X source shall:

(A) install, maintain and operate a reporting device to electronically report total daily mass emissions of NO_X and daily status codes to the District Central NO_X Station for each major NO_X source. Such data shall be reported by 5:00 p.m., of the following day. If the facility experiences a power, computer, or other system failure that prohibits the reporting of total daily mass emissions of NO_X and daily status codes, the Facility Permit holder shall be granted 24 hours to submit the required report. Between July 1, 1995 and December 31, 1995, NO_X emissions after the 24-hour extension, shall be calculated using interim reporting procedures set forth in Appendix A, Chapter 2. Starting January 1, 1996 and thereafter, NO_X emissions after the 24-hour extension shall be calculated pursuant to the missing data requirements set forth in Appendix A, Chapter 2. For each major NO_X source opting to comply with subparagraph (c)(9), reports of NO_X mass emissions shall be electronically filed on a monthly instead of daily basis; and

(B) submit Monthly Emissions Reports aggregating NO_X emissions from all major sources within 15 days following the end of each calendar month. In its Monthly Emissions Report the Facility Permit holder may correct daily transmitted data for that month provided such corrections are clearly identified and justified.

(C) Notwithstanding subparagraph (c)(3)(A), starting May 11, 2001 if a power, computer, or other system failure precludes the Facility Permit holder from reporting total daily mass emissions of NO_X and daily status codes by 5:00 p.m., the Facility Permit holder shall be granted 96 hours to submit the required report provided that the raw data as obtained by the direct monitoring device is stored at the facility. NO_X emissions reported after the 96-hour extension shall be calculated pursuant to the missing data requirements set forth in Appendix A, Chapter 2. The provisions of this_subparagraph shall be limited to no more than three non-consecutive occurrences per compliance year.

(D) The requirement of calculating emissions using Missing Data Procedures under subparagraph (c)(3)(A) shall not apply if the failure to report the total daily mass emissions of NO_X and daily status codes is due to a demonstrated failure at the District's Central Station preventing it from receiving the data. The Facility Permit holder shall submit the report within 48 hours of the problem being corrected, provided that the raw data as obtained by the direct monitoring device is stored at the facility. NO_X emissions reported after the 48-hour extension shall be calculated pursuant to the missing data requirements set forth in Appendix A, Chapter 2.

(4) Super Compliant Facilities

(A) Facilities operating at or below their adjusted 2003 Allocation as of their 1994 compliance year.

(i) The Facility Permit holder of major NO_X sources may reclassify its major NO_X sources to large NO_X sources provided that (1) the facility's annual NO_X emissions as properly reported in its 1994 compliance year APEP report are already at or below the level of its adjusted compliance year 2003 NO_X Allocation. The adjusted compliance year 2003 NO_X Allocation shall be the compliance year 2003 NO_X Allocation as calculated pursuant to Rule 2002 subdivision (e) plus any compliance year 2003 NO_X RTCs resulting from conversion of ERCs which the Facility Permit holder had applied to own by July 1, 1994 and has continuously owned, unless such RTCs have already been accounted for in the compliance year 2003 Allocation as established pursuant to Rule 2002 subdivision (e) and (2) it submits a complete application for NO_X Super Compliant status on or before December 2, 1996. The Executive Officer will provisionally approve for purposes of paragraph (c)(5) such application if the Facility Permit holder has retired all NO_X RTCs in excess of the facility's adjusted compliance year 2003 Allocation for each of the compliance years from the year of application submittal through the 2010 compliance year. The Facility Permit holder need not retire any RTCs (excluding converted

ERCs) which are held by transfer pursuant to Rule 2007 paragraph (e)(2); however, such non-retired RTCs must be converted into RTC certificates pursuant to Rule 2007 subdivision (g), transferred to a different holder, or retired. For the purposes of this rule, converted ERCs shall mean NO_X RTCs resulting from conversion of ERCs which the Facility Permit holder had applied to own by July 1, 1994 and has continuously owned.

(ii) Final approval of NO_X Super Compliant status shall be granted if the Executive Officer or designee approves the initial source test required by subparagraph (c)(4)(C) and the facility's total annual NO_X emissions has not exceeded its adjusted compliance year 2003 Allocation.

(B) Facilities not operating at or below their adjusted 2003 Allocation as of their 1994 compliance year.

(i) On or before December 2, 1996 the facility Permit holder of major NO_X sources may submit a complete application for NO_X Super Compliant status. Such application must also include a complete application for permit modifications to install NO_X emission reduction equipment or to make any other physical modifications to substantially reduce emissions from each major NO_X source to be reclassified as a large NOx source. The Executive Officer shall deny the application for Super Compliant status unless the applicant demonstrates the proposed modifications would comply with all applicable District rules and would permanently reduce the facility's total annual NO_X emissions to a level not to exceed its adjusted compliance year 2003 NO_X Allocation as defined in clause (c)(4)(A)(i), would not result in any increases in the mass emissions of any other air contaminant or in emissions to any other media, and would not result in any increases in receptor concentrations of any air contaminant in excess of the values identified in Table A-2 of Rule 1303;

(ii) Upon issuance of the permit to construct for the modification specified in clause (c)(4)(B)(i), the Executive Officer shall also issue a provisional approval of the facility's application for NO_X Super Compliant status for purposes of paragraph (c)(5).

(iii) Final approval of NO_X Super Compliant status shall be granted if the following provisions are met:

(I) An approved permit to operate has been issued for the modification specified in clause (c)(4)(B)(i);

(II) The facility's total annual NO_X emissions as reported in its APEP report are at a level at or below the facility's adjusted compliance year 2003 NO_X Allocation on a permanent basis no later than the facility's 1998 compliance year;

(III) The Facility Permit holder has retired all NO_X RTCs in excess of the facility's adjusted compliance year 2003 Allocation for each of the compliance years from the earlier of the facility's 1998 compliance year or the facility's first full compliance year with NO_X Super Compliant Facility status through the facility's 2010 compliance year. The Facility Permit holder need not retire any RTCs (excluding converted ERCs as defined in clause (c)(4)(A)(i) which are held by transfer pursuant to Rule 2007 paragraph (e)(2); however, such non-retired RTCs must be converted into RTC certificates pursuant to Rule 2007 subdivision (g), transferred to a different holder, or retired; and

(IV) The facility Permit holder has an approved initial source test as required under subparagraph (c)(4)(C).

(C) The Facility Permit holder shall have initial NO_X source tests conducted for each major NO_X source to be reclassified as a large

NO_X source. The initial source tests shall be conducted pursuant to Appendix A, Chapter 5, Subdivisions A and D and shall be completed prior to January 1, 1998 for Cycle 1 facilities and prior to July 1, 1998 for Cycle 2 facilities. Additionally, the Facility Permit holder shall select an equipment-specific concentration limit for each major source which will be reclassified as a large NO_X source. For each major source which will be reclassified as a large NO_X source that operates at two or more separate and significantly distinct operating loads, the Facility Permit holder may select no more than two equipment specific concentration limits, and assign one for each different operating load. The concentration limits selected shall be consistent with the source test results and at a level adequate to allow continuous compliance and shall be enforceable through permit conditions.

(D) Requirements to maintain Super Compliant status

Super Compliant status is contingent upon the Facility Permit holder meeting at all times the following provisions:

(i) Every major NO_X source at a Super Compliant NO_X facility which is reclassified as a large NO_X source shall be source tested a minimum of once every six months in order to verify compliance with the equipment-specific concentration limit. The source test shall be conducted pursuant to Appendix A, Chapter 5, Subdivisions A, B, and D and shall constitute the basis for assigning concentration limits. These source tests shall be conducted every two calendar quarters after the initial source test. If a source test is not conducted within three months after the required date, the facility shall no longer be considered Super Compliant, unless upon good cause the Executive Officer has granted a written extension of time. If the results of a source test indicate non-compliance with the concentration limit then the Facility Permit holder shall select a new concentration limit which is consistent with the source test results unless the Facility Permit holder demonstrates to the satisfaction of the Executive Officer or designee that no change is warranted.

If all tests conducted pursuant to this paragraph over a two-year period comply with the equipment-specific concentration limit then the facility shall have the option of reducing the source test frequency to once every four quarters. If any test conducted on a four quarter cycle exceeds the concentration limit then the facility shall return to conducting source tests every two quarters.

(ii) The facility's total annual NO_X emissions, as reported in its APEP report, shall not exceed the facility's adjusted compliance year 2003 NO_X Allocation. If there are such exceedances for two consecutive years or any three years, the facility shall no longer be considered Super Compliant. NOx emissions from portable equipment used in the manufacturing of asphalt rubber binder, which is owned and operated by a person other than the Facility Permit holder and used at a Super Compliant facility for not more than 1,500 hours in any one compliance year, need not be included in the APEP report.

(5) The Facility Permit holder of a facility which is provisionally approved for NO_X Super Compliant status shall have the option for each major NOx source to be reclassified as a large NOx source, in lieu of following the procedures specified in clauses E(1)(d)(i), E(1)(d)(ii), and E(1)(d)(iii) of Appendix A Chapter 2, to monitor and report emissions pursuant to paragraph (d)(2). This option shall be available to the Facility Permit holder retroactively from July 1, 1995 if the complete application for NO_X Super Compliant status is submitted on or before January 2, 1996, or retroactively from the date of application submittal if the complete application is submitted after January 2 and before December 3, 1996. If the facility is unsuccessful at obtaining designation as a NO_X Super Compliant Facility then the procedures specified in clauses E(1)(d)(i), E(1)(d)(ii), and E(1)(d)(iii) of Appendix A Chapter 2 shall apply retroactively to each major NOx source reclassified as a large NOx source for which NO_X emissions had been calculated pursuant to paragraph (d)(2) from the date the facility began monitoring and reporting major NO_X source emissions as large NO_X source emissions to the date a CEMS is installed and certified.

(6) After final approval of Super Compliant status, a Facility Permit holder may elect to discontinue its Super Compliant status and increase its annual Allocations above the level of its adjusted compliance year 2003 Allocation provided it first meets all of the following requirements:

(A) The Facility Permit holder submits an application to discontinue NO_X Super Compliant status and to have all sources at the facility that were reclassified from major NO_X sources to large NO_X sources pursuant to paragraph (c)(4) permanently revert back to major NO_X sources;

(B) The Facility Permit holder installs, operates, and certifies in compliance with Rule 2012 paragraphs (c)(2) and (c)(3) monitoring and reporting systems on each source at the facility that was reclassified from a major NO_X source to a large NO_X source pursuant to paragraph (c)(4); and

(C) The Facility Permit holder acquires, pursuant to Rule 2007, sufficient RTCs to ensure that the facility continuously operates in compliance with Rule 2004 subdivision (d).

(7) If a facility designated as a NO_X Super Compliant Facility pursuant to paragraph (c)(4) exceeds its adjusted compliance year 2003 NO_X Allocation, then the facility shall acquire, pursuant to Rule 2007, sufficient RTCs to cover such exceedance and shall be considered in violation of Rule 2004(d)(1).

(8) If the Executive Officer determines that a facility designated as a NO_X Super Compliant Facility exceeds its adjusted compliance year 2003 NO_X Allocation for two consecutive years or any three years, then that facility shall no longer be considered Super Compliant. If a facility loses its Super Compliant status pursuant to this paragraph or subparagraph (c)(4)(D), all sources at the facility that were reclassified from major NO_X sources to large NO_X sources pursuant to paragraph (c)(4) shall permanently revert back to major NO_X sources and shall become subject to the monitoring and reporting requirements of paragraphs (c)(2) and (c)(3) according to the following schedule:

(A) Within one month from the end of the compliance year, submit a monitoring, reporting, and recordkeeping plan specifying the use of CEMS;

(B) During the shorter of the first twelve months from the end of the compliance year or until the facility complies with paragraphs (c)(2) and (c)(3), the Facility Permit holder shall comply with the monitoring requirements of paragraph (h)(3) of this rule; and

(C) Within one year from the end of the compliance year, comply with paragraphs (c)(2) and (c)(3) and have appropriate direct monitoring equipment installed and certified pursuant to Appendix A.

(9) Non-Operated Major NOx Source

Subparagraphs (c)(2)(A) and (c)(2)(B) shall not apply to a major NOx source if the Facility Permit holder complies with the following requirements.

(A) The Facility Permit holder submits an application for each major NOx source to classify such source to be a non-operated major NOx source, demonstrating to the satisfaction of the Executive Officer that such source will not be operated in the current or next compliance year, and receives written approval from the Executive Officer. The Executive Officer shall further not approve an application to classify a major source to be a non-operated major NOx source if such source had previously been classified as a non-operated source for any time during the 18 calendar months prior to the filing date of the application.

(B) The Facility Permit holder accepts and complies with all permit conditions imposed to ensure compliance with subparagraph (c)(9)(C) and (c)(9)(D).

(C) The Facility Permit holder shall comply with the requirements under either subclause (i) or (ii):

(i) The Facility Permit holder shall:

(I) disconnect fuel feed lines and place flanges at both ends of the disconnected lines, and

(II) render the source non-operational by either disconnecting the process feed lines and place flanges at both ends of the disconnected lines or removing a major component of the source necessary for its operation.

(ii) The Facility Permit holder shall monitor the source with an operating CEMS that was certified to monitor emissions from that source in accordance with District Rule 218 - Stack Monitoring, Rule 1135 - Emissions of Oxides of Nitrogen from Electric Power Generating Systems, or Rule 2012 and Appendix A and maintain records demonstrating the source's non-operational status as required by the applicable rule.

(D) A source, which has been approved as a non-operated source pursuant to paragraph (c)(9), shall not be operated until the following requirements are met:

(i) The Facility Permit holder shall provide written notification to the Executive Officer that the source will be operated. The notification shall be made no less than 30 days prior to starting operation of the source.

(ii) The source meets the requirements of subparagraph (c)(2)(A) or (c)(2)(B) no later than 30 days after the start of operation except as provided under paragraph (c)(10). Until the source meets the requirements of subparagraph (c)(2)(A) or (c)(2)(B), emissions shall be determined pursuant to the Missing Data Procedures as specified under Rule 2012, Appendix A, Chapter 2, Subdivision E.

(10) A non-operated major NOx source qualifies for a one-time only CEMS certification period if:

(A) the source has never been monitored by a RECLAIM certified CEMS since October 15, 1993, and

(B) the source has been in compliance with paragraph (c)(9) during the 12 months prior to the date the source was operated.

This one-time only CEMS certification period shall commence on the first day of any operation in any compliance year and ends on the date the CEMS is certified or 12 calendar months from the first day of operation, whichever date is earlier. By the end of this CEMS certification period, the Facility Permit holder shall install, operate, and maintain all required monitoring, reporting, and recordkeeping systems. During this CEMS certification period, the Facility Permit holder shall comply with the monitoring, reporting, and recordkeeping requirements of paragraphs (h)(2) and (h)(3).

(11) If an approved non-operated major NOx source fails to meets the requirements of the paragraph (c)(9) that source shall no longer be considered a non-operated major NOx source, and the facility permit holder of the source shall be considered in violation for each day from the start of the compliance year and emissions shall be determined as if the source had been operating from the start of the compliance year according to Missing Data Procedures as specified under Rule 2012, Appendix A, Chapter 2, clause (E)(1)(d)(iii), except for those days in which the Facility Permit holder can conclusively prove that the source has not been operated.

(d) Large NO_X Source

(1) Large NO_X Source is any one of the following NO_X emitting equipment:

(A) any boiler, furnace, oven, dryer, heater, incinerator, test cell and any liquid or gaseous fueled equipment with a maximum rated capacity:

(i) greater than or equal to 40 but less than 500 million Btu per hour and an annual heat input of 90 billion Btu per year or less; or

(ii) greater than or equal to 10 but less than 40 million Btu per hour and an annual heat input greater than 23 billion Btu per year.

(B) any internal combustion engine with rated brake horsepower:

(i) greater than or equal to 1,000 bhp and operating 2,190 hours per year or less; or

(ii) greater than or equal to 200 but less than 1,000 bhp and operating more than 2,190 hours per year;

(C) any gas turbine rated greater than or equal to 0.2 but less than 2.9 megawatts, excluding any emergency standby equipment or peaking unit;

(D) any kiln or calciner with rated process weight less than 10 tons per hour or processing less than 21,900 tons per year;

(E) any sulfuric acid production unit;

(F) any source at a Super Compliant Facility subject to, and meeting, the requirements of paragraph (c)(4) and which would otherwise be a major NO_X source.;

(G) any NO_X source or process unit elected by the Facility Permit holder or required by the Executive Officer to be monitored with a CPMS;

(H) any NO_X source or process unit for which NO_X emissions reported pursuant to Rule 301 - Permit Fees, were equal to or greater than 4 tons per year but less than 10 tons per year for any calendar year from 1987 to 1991, inclusive, excluding NO_X sources or process units listed under subparagraphs (c)(1)(A) through (c)(1)(H), and (e)(1)(A) through (e)(1)(D).

(2) The Facility Permit holder of a large NO_X source shall comply with either paragraphs (c)(2) and (c)(3); or (c)(2), (d)(2)(B) and Appendix A, Chapter 3, Subdivision K for any large source; or elect to comply with the following:

(A) install, maintain and operate a totalizing fuel meter and any other device specified by the Executive Officer or designee as necessary to determine monthly fuel usage, and all other applicable variables specified in Appendix A, Chapter 3, Table 3-A; and

(B) install, maintain and operate a modem or any reporting device approved by the Executive Officer or designee to be equivalent in accuracy, reliability, and timeliness, or use the District Internet Web Site to report total monthly mass emissions of NO_X to the District Central NO_X Station for each large NO_X source. Such data shall be reported within 15 days following the end of each calendar month; and

(C) accept the emission factor, equipment-specific emission rate or concentration limit, as specified pursuant to subdivision (f) in the Facility Permit, as the sole method for determining mass emissions for all purposes, including, but not limited to, determining:

(i) compliance with the annual Allocations;

(ii) excess emissions;

(iii) the amount of penalties; and

(iv) fees; and

(D) monitor one or more measured variables as specified in Appendix A in order to ensure the applicability and accuracy of any equipment-specific emission rate specified in the Facility Permit; and

(E) comply with all applicable provisions of subdivision (f).

(e) NO_X Process Unit

(1) NO_X Process Unit means any piece of the following NO_X emitting equipment:

(A) any boiler, furnace, oven, dryer, heater, incinerator, test cell and any liquid- or gaseous-fueled equipment with maximum rated capacity:

(i) greater than or equal to 10 but less than 40 million Btu per hour and an annual heat input of 23 billion Btu per year or less;

(ii) greater than 2 but less than 10 million Btu per hour; or

(iii) less than or equal to 2 million BTU per hour if the equipment is subject to permit requirements.

(B) any internal combustion engine with rated brake horsepower:

(i) greater than or equal to 200 but less than 1,000 bhp and operating 2,190 hours per year or less;

(ii) greater than 50 but less than 200 bhp; or

(iii) less than or equal to 50 bhp if the equipment is subject to permit requirements.

(C) any portable combustion equipment which is not a major or large source;

(D) any emergency standby equipment or peaking unit ;

(E) any other NO_X source that is not a large or major NO_X source or equipment designated in Rule 219 - Equipment Not Requiring a Written Permit Pursuant to Regulation II.

(2) The Facility Permit holder of a NO_X process unit shall comply with paragraph (c)(2), and (c)(3), or paragraph (d)(2), for any process unit, or elect to comply with the following:

(A) install, maintain and operate a totalizing fuel meter and/or timer or any device approved by the Executive Officer or designee to be equivalent in accuracy, reliability, reproducibility, and timeliness for the NO_X process unit, to measure quarterly fuel usage or other applicable variables specified in Table 2012-1, and Appendix A, Chapter 4, Table 4-A; and

(B) report quarterly mass emissions of NO_X to the District Central Station 30 days after the end of each of the first three quarters and 60 days after the last quarter of a compliance year for each process unit using a modem, the District Internet Web Site or any reporting device approved by the Executive Officer to be equivalent in accuracy, reliability, and timeliness; and

(C) accept the emission factor, concentration limit, or equipment-specific or category-specific emission rate, as specified pursuant to subdivision (f) of this Rule and in the Facility Permit, as the sole method for determining mass emissions for all purposes, including, but not limited to, determining:

(i) compliance with the annual Allocations;

(ii) excess emissions;

(iii) the amount of penalties; and

(iv) fees; and

(D) comply with all applicable provisions of subdivision (f).

(E) Facility Permit holders that opt for a concentration limit in Subparagraph (e)(2)(C) for a process unit shall comply at all times with that NO_X concentration limit in ppm measured over any continuous 60 minutes as specified in the Facility Permit for that source.

(f) Permit Conditions for Large Sources and Process Units

(1) Starting January 1, 1994 for Cycle 1 facilities and starting July 1, 1994 for Cycle 2 facilities, calculations of mass emissions from each large source or process unit shall be based upon the emission factor specified in Rule 2002 - Allocations for Oxides of Nitrogen (NO_X) and Oxides of Sulfur (SO_X). The emission factor for each large source or process unit will be specified in the Facility Permit, and will remain valid unless amended by the Executive Officer pursuant to paragraphs (f)(2), (f)(3) or (f)(4).

(2) On and after January 1, 1995 for Cycle 1 facilities and July 1, 1995 for Cycle 2 facilities, the Facility Permit holder of a large source shall:

(A) comply at all times with an equipment-specific NO_X concentration limit in ppm measured over any continuous 60 minutes as specified in the Facility Permit for that source; according to the requirements specified in Appendix A, Chapter 3 (large sources); or

(B) establish an equipment-specific emission rate that is reliable, accurate and representative of that source's emissions, according to the requirements specified in Appendix A, Chapter 5.

(3) A Facility Permit holder may apply to the Executive Officer or designee to amend the concentration limit or equipment-specific emission rate for a large source, or to amend the emission factor to a concentration limit, equipment-specific emission rate, or category-specific emission rate for a process unit, in the Facility Permit, at any time. If the applicant demonstrates to the Executive Officer or designee that the equipment-specific or category-specific emission rate is reliable, accurate and representative for the purpose of calculating NO_X emissions, the Executive Officer or designee will amend the Facility Permit to incorporate the equipment-specific or category-specific emission rate. No demonstration will be required to amend the Facility Permit to incorporate the alternative concentration limit, provided the large source or process unit complies with that limit in ppm over any continuous 60 minutes. The alternative concentration limit or equipment-specific emission rate for a large source, and the concentration limit, equipment-specific emission rate, or category-specific emission rate for a process unit, shall take effect prospectively from the date the Facility Permit is amended.

(4) The Executive Officer or designee may amend the Facility Permit at any time to specify a concentration limit or an equipment-specific emission rate for a large source, or a concentration limit, equipment-specific emission rate, or category-specific emission rate for a process unit, if the concentration limit, equipment-specific emission rate, or category-specific emission rate is determined to be more reliable, accurate, or representative of that source's or unit's emissions than the previous emission factor, or concentration limit or emission rate specified in the

Facility Permit. The alternative concentration limit or equipment-specific emission rate for a large source, or concentration limit, equipment-specific emission rate or category-specific emission rate for a process unit shall take effect prospectively from the date the Facility Permit is amended.

(g) General Requirements

(1) A Facility Permit holder shall at all times comply with all requirements specified in subdivisions (c), (d), (e), (f), (g), (h), and (i) for monitoring, reporting and recordkeeping, including but not limited to, measuring, reporting, time-sharing, determining mass emissions, and installing, maintaining or operating monitoring, measuring and reporting devices, in accordance with the applicable requirements set forth in Appendix A.

(2) The monitoring system and the applicable method for determination of mass emissions for each NO_X source or process unit will be specified in the Facility Permit, in accordance with the applicable requirements set forth in Appendix A.

(3) The time-sharing of CEMS among NO_X sources may be allowed by the Executive Officer or designee in accordance with the requirements for time-sharing specified in Appendix A. In such cases, the Executive Officer or designee will specify conditions in the Facility Permit upon which time-sharing may occur.

(4) Any monitoring system certified prior to October 15, 1993 requiring a change to its full scale span range in order to meet the certification requirements set forth in Appendix A, shall be recertified by the Executive Officer or designee in accordance with the recertification requirements specified in Chapter 2, Section B.15, in Appendix A.

(5) The Executive Officer or designee may at any time require a Facility Permit holder to use a specific monitoring and reporting system if it is determined that the elected system is inadequate to accurately determine mass emissions.

(6) The sharing of totalizing fuel meters may be allowed by the Executive Officer or designee if the fuel meter serves large sources or process units which have the same emission factor or concentration limit or emission rate. The sharing of totalizing fuel meters shall not be allowed:

(A) if the fuel meters measure annual heat input as specified in clauses (d)(1)(A)(i) and (e)(1)(A)(i); or

(B) between large sources and process units.

(7) A Facility Permit holder of any NO_X source, process unit, or piece of equipment which is exempt from permit requirements pursuant to Rule 219 - Equipment Not Requiring A Written Permit Pursuant to Regulation II, shall determine NO_X emissions according to the methodology specified in Appendix A. Process units or equipment exempt from permit requirements pursuant to Rule 219 shall report such NO_X emissions in the Quarterly Certification of Emissions required by Rule 2004 - Requirements. Emissions from equipment exempt from permit requirements pursuant to Rule 219 shall also be reported quarterly to the District Central Station by the end of the quarterly reconciliation period as specified under Rule 2004(b) – Compliance Period and Certification of emissions. Alternatively, these emissions may be reported using the District Internet Web Site.

(8) A Facility Permit holder shall at all times comply with all applicable requirements specified in this rule and Appendix A for monitoring, reporting and recordkeeping of operations of RECLAIM NOx sources that are not included in the Facility Permit so as to determine and report to the District Central Station the quarterly emissions from these sources by the end of the quarterly reconciliation period as specified under Rule 2004(b). These sources may include, but are not limited to, rental equipment, equipment operated by contractors, and equipment operated under a temporary permit or without a District permit. In addition, the Facility Permit holder shall include emissions from these sources in the Quarterly Certification of Emissions required by Rule 2004.

(h) Compliance Schedule

(1) Facilities with existing CEMS and fuel meters as of October 15, 1993 shall continue to follow recording and reporting procedures required by District rules and regulations in effect immediately prior to October 15, 1993, until December 31, 1994 for Cycle 1 facilities and June 30, 1995 for Cycle 2 facilities.

(2) Between January 1, 1994 and December 31, 1994 for Cycle 1 facilities and between July 1, 1994 and June 30, 1995 for Cycle 2 facilities, interim emission reports shall be submitted to the District by the Facility

Permit holder. The interim reports shall comply with all of the requirements of this rule and Appendix A, except that the reporting frequency shall be monthly for major and large sources and quarterly for process units. Such reports shall be submitted by the fifteenth (15^{th}) day of each month for major and large sources and as specified in paragraph (b)(2) of Rule 2004 - Requirements, for process units.

(3) A Facility Permit holder shall install, maintain and operate a totalizing fuel meter for each major source and a totalizing fuel meter and/or timer or any device approved by the Executive Officer or designee to be equivalent in accuracy, reliability, reproducibility, and timeliness for each large source or process unit by January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities, except that sharing of such devices may be allowed pursuant to paragraph (g)(6).

(4) All required or elected monitoring and reporting systems specified in subdivisions (c), (d), (e), (f), and (g) shall be installed no later than December 31, 1994 for Cycle 1 facilities and June 30, 1995 for Cycle 2 facilities. Monitoring, Reporting, and Recordkeeping (MRR) Forms will be provided by the Executive Officer or designee by November 15, 1993 for Cycle 1 facilities and April 15, 1994 for Cycle 2 facilities. The information required on such MRR forms shall be submitted no later than December 31, 1993 for Cycle 1 facilities and June 30, 1994 for Cycle 2 facilities.

(5) The Facility Permit holder of an existing or new facility which elects to enter RECLAIM or a facility which is required to enter RECLAIM shall install all required or elected monitoring, reporting and recordkeeping systems no later than 12 months after entry into RECLAIM. During the 12 months prior to the installation of the required or elected monitoring, reporting and recordkeeping systems the Facility Permit holder shall comply with the monitoring reporting, and recordkeeping requirements of paragraphs (h)(2) and (h)(3) of this rule.

(6) The Facility Permit holder which installs a new major NOx source at an existing facility shall install, operate, and maintain all required or elected monitoring, reporting and recordkeeping systems no later than 12 months after the initial start up of the major NOx source. During the interim period between the initial start up of the major NOx source and the provisional certification date of the CEMS, the Facility Permit holder

shall comply with the monitoring requirements of paragraph (h)(2) and (h)(3) of this rule.

(i) Recordkeeping

The Facility Permit holder of a major or large NO_X source or NO_X process unit shall maintain all data required to be gathered, computed or reported pursuant to this rule and Appendix A for three years after each APEP report is submitted to the District except that all data gathered or computed for intervals of less than 15 minutes shall be maintained for a minimum of 48 hours. The Facility Permit holder of a major NOx source which is required to comply with 40 CFR Part 75 may instead opt to comply with the applicable recordkeeping requirements under 40 CFR Part 75. All records shall be made available to the District staff upon request.

(j) Source Testing

(1) All required source testing shall comply with applicable District Source Test Methods 1.1, 1.2, 2.1, 2.2, 2.3, 3.1, 4.1, 7.1, 100.1, and EPA Method 19.

(2) Every large NO_X source shall be source tested no later than December 31, 1996 for Cycle 1 facilities and June 30, 1997 for Cycle 2 facilities, and subsequently tested within every three-year period thereafter. Any source test conducted to satisfy this requirement must be conducted at least 12 months following the tests submitted to satisfy the previous three-year period. Such source test results shall be submitted to the District within 60 days of the date the source test was conducted. In lieu of submitting the first source test report, the Facility Permit holder may submit the results of a source test not more than three years old which meets applicable requirements of this rule when conducted. If a large source has not been operated within the same quarter of the date a source test is required, the source test may be conducted by the end of seven consecutive days or 15 cumulative days of resumed operation. The Facility Permit holder shall keep daily records to demonstrate that the large source had not been operated for the three month period and upon resumption of operation the Facility Permit holder shall keep records of each day operated until the required test. The source testing requirement does not apply to large sources which comply with paragraphs (c)(2) and

(c)(3), or paragraphs (c)(2), (d)(2)(B), and Appendix A, Chapter 3, Subdivision K.

(3) An equipment-specific emission rate or category-specific emission rate for process units shall comply with source testing guidelines to be established by the Executive Officer or designee by March 31, 1994.

(4) Every process unit that is approved by the Executive Officer to use a concentration limit for emission reporting shall be source tested every five-year period, with the first five-year period ending on December 31, 2004 for Cycle 1 facilities and June 30, 2005 for Cycle 2 facilities. The compliance date for the first source test shall be within 12 months of the approval of the concentration limit by the Executive Officer but, no later than the last day of the five-year period in which the use of a concentration limit is approved by the Executive Officer. Any source test conducted to satisfy this requirement must be conducted at least 12 months following the tests submitted to satisfy the previous five-year period. Such source test results shall be submitted to the District within 60 days of the date the source test was conducted. If a process unit has not been operated within the prior quarter of the date a source test is required, the source test may be conducted by the end of either seven consecutive days or 15 cumulative days of resumed operation. The Facility Permit holder shall keep daily records to demonstrate that the process unit had not been operated for the three month period and upon resumption of operation the Facility Permit holder shall keep records of each day operated until the required test. Test firings of emergency standby equipment, which are less than 60 minutes in duration, are not considered operation for the purposes of these source test requirements so long as such test firings are done to verify availability of the unit for their intended use and once such test firings are completed the units are shutdown. Records of the date and duration when the unit is test fired shall be maintained for a period of three years, and shall be made accessible to the Executive Officer upon request.

(k) Exemption

The provisions of this rule shall not apply to gas flares.

(l) Appeals

The Facility Permit holder of a facility which has established Super Compliant status shall have a maximum of ten calendar days from the receipt of notification that the facility is no longer Super Compliant in which to file an appeal of such finding to the District Hearing Board in accordance with the requirements of Rule 216.

(m) Appendix A

All provisions of Appendix A are incorporated herein by reference.

Attachment: Appendix A - "Protocol for Monitoring, Reporting and Recordkeeping for Oxides of Nitrogen (NO_X) Emissions."

Table 2012-1

MEASURED VARIABLES AND REPORTED DATA FOR NO_X SOURCES

NO_X SOURCES	MEASURED VARIABLES	RECORDING FREQUENCY	REPORTED DATA	TRANSMITTING/ REPORTING FREQUENCY
All sources subject to Paragraphs (c)(2) and (c)(3)	Stack NO_X concentration, Exhaust flow rate, and Status codes OR Stack NO_X concentration, Stack O_2 concentration, Fuel flow rate, and Status codes	Once every 15 minutes	Total daily mass emissions from each source Daily status codes	Once a day for transmitting/ once a month for reporting
Large sources subject to Paragraph (d)(2)	Fuel usage OR Exhaust flow rate (for systems with stack flow monitors)	Monthly	Total Monthly mass emissions from each source	Once a month for reporting

NO_X Process units subject to Paragraph (e)(2)	Fuel usage OR Exhaust flow rate (for sources with stack flow monitors) OR Operating time and Production/ Processing/Feed rate (for sources permitted with emission rates corresponding to the measured variable)	Quarterly	Total quarterly mass emissions	Once a quarter for reporting

8/28/96

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

RULE 2012(j)(3) TESTING GUIDELINES (PROTOCOL) FOR ALTERNATIVE NITROGEN OXIDES EMISSION RATE DETERMINATION AT PROCESS UNITS

MARCH 31, 1994

SOURCE TESTING AND ENGINEERING BRANCH

APPLIED SCIENCE AND TECHNOLOGY

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

RULE 2012(j)(3)
TESTING GUIDELINES (PROTOCOL)
FOR ALTERNATIVE NITROGEN OXIDES
EMISSION RATE DETERMINATION
AT PROCESS UNITS

MARCH 31, 1994

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RULE 2012(j)(3) TESTING GUIDELINES FOR ALTERNATIVE NITROGEN OXIDES EMISSION RATE DETERMINATION AT PROCESS UNITS

1.0 OVERVIEW AND APPLICABILITY

The emission rate for a process unit may be amended pursuant to District Rule 2012(f)(3) and 2012(f)(4), if that alternative rate is demonstrated to be more reliable, accurate, and representative than the previous rate used. District Rule 2012(j)(3) requires at a minimum that such alternative rate comply with source testing guidelines to be established by the Executive Officer. This guideline has been developed to ensure standardization of test procedures including the use of: specified test conditions, required test methods, specifications for test equipment, data collection/reporting, and quality assurance requirements. This guideline will be applicable to all process units, as defined in Rule 2012(e)(1).

An independent testing laboratory, which meets the requirements of South Coast Air Quality Management District's Rule 304, Paragraph (L), and is approved by the SCAQMD to conduct testing under these guidelines, may conduct the test. The laboratory shall, in conducting the test, prepare a report of findings, including all raw data sheets/charts, and analytical data. Testing must demonstrate to the satisfaction of the Executive Officer that the proposed alternative Emission Rate from the operation of a process unit was determined using the guidelines described herein.

When a process unit cannot be tested using these guidelines, the guidelines may be modified following written approval of the Executive Officer.

2.0 ENVIRONMENTAL CRITERIA/ TEST CONDITIONS

2.1 AMBIENT TEMPERATURE

The ambient temperature shall be above 60^{o}F during sampling. Temperatures shall be monitored and recorded before and after each test.

2.2 RELATIVE HUMIDITY

The relative humidity shall be between 20% and 65% during the test. It shall be recorded before and after each test.

3.0 INSTRUMENTATION

All instrumentation within this section and pertaining to this protocol shall be calibrated as a minimum within the requirements set forth in SCAQMD Source Test Methods Chapter III, Calibrations.

3.1 PRESSURE MEASUREMENT

Pressure measurement instruments shall have an error no greater than the following values:

Measurement	Accuracy	Precision
Gas and Liquid Pressure	± 2% (of Range)	± 2% (of Range)

3.2 TEMPERATURE MEASUREMENTS

Temperature measuring instruments shall have an error no greater than the following values:

Accuracy	Precision
± 1.5% of Range	± 1.5% of Range

3.3 FUEL GAS FLOW

The quantity of fuel used by the process unit shall be measured in cubic feet with a dry gas meter and associated readout device. The dry gas meter reading shall be corrected to standard conditions ($60^{o}F$, 14.7 psia), and adjusted for instrument calibration. Calibration curves shall be used if required. The overall accuracy of gas flow measurements shall be equal to or less than 2% of the actual value.

3.4 **LIQUID FUEL FLOW MEASUREMENTS**

The accuracy of liquid flow measurements, using calibration curves if required, shall be equal to or less than ± 2% of the actual value. Calibration data shall be submitted with the test report.

3.5 **TIME**

The elapsed time measurement shall be measured with an instrument that is accurate within ± 0.5 seconds per hour.

3.6 **FLUE GAS ANALYSIS**

Operational procedures and guidelines for selection of portable electrochemical analyzers shall be established by the Executive Officer. Testing procedures using chemiluminescent NOx analyzers and non-dispersive infrared (NDIR) CO_2 analyzers shall comply with District Method 100.1.

3.6.1 <u>NO_x CONCENTRATION</u> A chemiluminescence or electrochemical NO_x analyzer shall be employed to measure NO_x in the flue gas. To insure that ammonia will not bias the sample, special precautions must be used to select the proper chemiluminescent analyzer.

3.6.2 O_2 CONCENTRATION An electrochemical analyzer shall be employed to measure oxygen in the flue gas. Minimum manufacturer's performance specifications of the analyzer shall be as follows:

Measurement	Range	Accuracy	Resolution
O_2	0 - 20%	± 5% of Reading	± 0.5%

3.6.3 CO_2 CONCENTRATION CO_2 concentration may be determined by stoichiometric calculation using oxygen measurements for fuels with known or stable compositions. Note for mixed fuels with established F-Factors, an independant CO_2 analyzer using a non-dispersive infrared (NDIR) analyzer is required for quality control procedures, as described in 40 CFR 60, Appendix A, Method 3B.

3.7 SAMPLE SYSTEM

3.7.1 Open Ended Sample Probes Open ended sample probes shall be used. A filter shall be installed to prevent clogging.

3.7.2 Sample Lines The sample line shall be of Teflon construction, or equivalent. The sampling line should be heated to prevent condensation.

3.7.3 Sample Conditioning System The NO_x and O_2 analyzers shall sample flue gas delivered by a single sample conditioning system. The gases shall be measured simultaneously after undergoing identical sample conditioning.

3.7.3.1 Moisture Removal; Moisture removal shall be used to minimize loss of nitrogen dioxide. Moisture knock-out techniques such as low temperature moisture traps, or a permeation-type dryer shall be employed to dry the sample gas to a dew point of $50^{O}F$, or lower.

3.7.3.2 Sample Pump The sample pump shall be of sufficient power to draw exhaust gases at a constant flow, with a minimal response time for the measurement system. The pump shall be constructed of materials that are nonreactive to the sampled gases.

3.8 HEATING VALUE

Heating value or gas composition of the fuel must be measured for fuels not listed in Table 3-D of the Protocol for Rule 2012. If the heating value is measured, the accuracy of the measurement device shall be ± 1% of full scale. The precision of the device shall be ± 2 Btu/dscf. Calibration shall be conducted weekly using the device manufacturer's directions.

If the composition of the fuel is measured, it shall be measured with a gas chromatograph having a TC detector. Methane, ethane, propane, C4+, CO_2, and permanent gases will be measured directly. Nitrogen may be determined by difference. The reproducibility of the gas chromatograph shall be $\pm$ 1% of full scale for each measured component. The heating value shall be calculated in accordance with Form F.

4.0 ANALYTICAL METHODS

4.1 START UP

4.1.1 <u>ANALYZERS</u> Allow analyzers to warm up according to manufacturer's instructions.

4.1.2 <u>SAMPLE CONDITIONING SYSTEM</u> Energize sample pump and sample line. Allow temperatures and flows to come to equilibrium.

4.2 ANALYZER CALIBRATION

Use NIST traceable calibration gases which are certified to a minimum accuracy of ± 2%. A high span calibration gas shall be selected such that the emission concentrations will be greater than 20% and less than 95% of the high span calibration gas value. Calibrate the analyzers according to the manufacturer's instructions using zero gas, and high-range gas. The calibration of each analyzer must be checked prior to and after each test. Linearity may be checked using a calibrated gas divider.

The analyzer shall meet the calibration error, drift, linearity, and bias requirements of District Method 100.1. A statistically equivalent methodology for meeting District Method 100.1 requirements may be used upon approval by the Executive Officer.

4.3 SAMPLE POINT LOCATION

The sampling point shall be located at the center of the exhaust duct at a distance of eight diameters downstream, and two diameters upstream from flow disturbances, as described in District Method 1.1. For sampling points which do not meet these criteria, a minimum of three traverse points shall be located along the diameter of the highest expected stratification. The traverse points shall be 16.7, 50.0, and 83.3 percent of the diameter. Sampling shall begin after the process unit has reached steady state as defined in Section 5 of the guidelines.

4.4 DATA RECORDING

The output of each analyzer shall be recorded on a print-out. The recorder must allow each data point to be read at least once every 3 minutes.

5.0 TEST PROCEDURE

5.1 HEAT INPUT

The process unit shall be adjusted to its "normal operating range" (hourly Btu input rate). This range shall cover operations for at least 80% of the entire operating time. For normal operating ranges which are unknown, the device shall be tested within ± 2% of the manufacturer's specified hourly BTU input rate. Burners shall be checked and adjusted to the correct operation criteria established by the operator of the equipment or manufacturer for that appliance. These burner criteria shall be noted in the test report.

5.2 EMISSION TESTING

5.2.1 START-UP Select four test conditions in accordance with Chapter 5 of the Rule 2012 Protocol. At each test condition, allow the device to operate until equilibrium conditions are attained. Generally, equilibrium is defined by the following conditions during a 15 minute interval:*

A) Temperature changes in the flue gas of not more than ± 10°F between readings 15 minutes apart when the flue gas temperature thermocouple is located in the center position of the exhaust;

* Equilibrium conditions can be unit specific, and may differ from the general criteria listed. Process units which do not meet these general conditions shall describe the equilibrium conditions under which the units were tested in the test report.

B) NOx changes in the flue gas of not more than ± 5 percent from the mean sampled over the 15 minute interval measured at the center of the exhaust duct;

C) O_2 changes in the flue gas of not more than ± 0.50 percent (± 5000 ppm) from the mean sampled over the 15 minute interval at the center of the exhaust duct.

5.2.2 SINGLE POINT SAMPLING At the start of the test, record the time and gas meter reading. Do not interrupt the flow to the process unit. At five minute intervals, record the instantaneous NO_x and O_2 concentrations during a thirty minute test period. Record the process parameters in Form A. Determine the arithmetic mean of O_2 and NO_x concentration measured during the thirty minute test period. If required, collect a sample of fuel for composition analysis, or use a calorimeter to measure heating value. Record the measured variables listed in Table 4-A of the Protocol for Rule 2012.

5.2.3 TRAVERSE SAMPLING If a sample traverse is required, identify the traverse point being sampled on the analyzer print-out and record the concentration of NOx and O_2 at each point. At 5 minute intervals, progressively traverse the stack diameter along the path determined in Paragraph 4.3. Repeat the traverse a second time such that no two points are measured consecutively. Record the process parameters in Form A. If required, collect a sample of fuel for composition analysis, or use a calorimeter to measure heating value. Record the measured variables listed in Table 4-A of the Protocol for Rule 2012.

6.0 CALCULATIONS

Calculations should be carried out to at least one significant digit beyond that of the acquired data and then should be rounded off after final calculation to three significant digits for each run. All rounding off of numbers should be in accordance with the ASTM E380-82 procedures.

6.1 HEATING VALUE

If heating value is measured, H equals that value in Btu/dscf.

Note that if the heating value is determined from a fuel gas composition analysis as described in Section 3.8 above, the calculated heating value must be corrected to a standard temperature of 60 degrees Fahrenheit.

6.2 F-FACTOR CALCULATION

For fuels not listed in Table 19-1 (40 CFR 60 Appendix A, Method 19), an F-Factor may be determined using procedures described in paragraph 3.2 of Method 19. An explanation of the analytical procedures used for determining the ultimate analysis for the fuel shall be provided with the test report.

The F-Factor shall not be used in cases where enriched oxygen is used, non-fuel sources of carbon dioxide are present (e.g., lime kilns and calciners), and the oxygen content of the stack is 19 percent or greater.

6.3 EMISSION RATE OF NO_X

6.3.1 CALCULATIONS USING OXYGEN BASED F FACTOR Compute using the following (see also Form G):

$$E = (1.195\times10^{-7}) \frac{20.9}{(20.9-b)} (F_d) (C_d)$$

Where:

E = NOx Emission Rate (lb/MMBtu);
b = Exhaust gas oxygen concentration (%), dry basis
F_d = Oxygen based F Factor, dry basis.
C_d = Concentration of NOx (ppm), dry basis

6.3.2 CALCULATIONS USING CARBON DIOXIDE BASED F FACTOR

Compute using the following (see also Form H):

$$E = (1.195\times10^{-7}) \frac{100}{b} (F_c) (C_d)$$

Where:

E = NOx Emission Rate (lb/MMBtu);
b = Exhaust gas CO_2 concentration (%), dry basis
F_c = CO_2 based F Factor, dry basis.
C_d = Concentration of NOx (ppm), dry basis

6.4 STATISTICAL GUIDELINES

The statistical guidelines located in Chapter 5, Paragraph F of the Rule 2012 Protocol shall be applied to the test data. All calculations must be submitted with the final report.

7.0 REPORT

7.1 TEST RESULTS

The following forms may be used in reporting test results:

Form A. General Information

Form B. Emissions Measurements- Single Point Sampling

Form C. Emissions Measurements- Traverse Sampling

Form D. Analyzer Calibration and Drift Data

7.2 FORMS USED FOR PERFORMING THE CALCULATIONS

Form E. Correction of gas concentrations due to drift.

Form F. Correction of gas meter reading and determination of firing rate.

Form G. Calculation of NOx Emission Rate

7.3 REPORT FORMAT

The following information is to be included in the test report:

1. All digital printouts, must be included in the final report and must be clearly identified as to:

-location/source
-operator initials
-date/running times
-actual test interval
-contaminant/diluent
-range changes
-range of measurement
-calibrations
-cal gas concentration/cyl. no.
-range of calibration

2. A summary of the Source Test results.

3. A brief process description. Indicate equipment operation during testing; as well as any other information which may influence the final report.

4. A simple schematic diagram of the process, showing the sampling location, with respect to the upstream and downstream flow disturbances.

5. The sampling and analytical procedures. Be specific about all aspects of sampling and analysis. Include diagrams of test equipment and methods.

6. Complete raw field data, including production data indicative of the testing interval, analyses, and the test results (show all calculations).

7. Calibration data regarding all sampling and measuring equipment utilized during testing (see <u>District Source Testing Manual, Chapter III</u> or

"Quality Assurance Handbook For Air Pollution Measurement Systems", Vol. III, U.S. EPA-600/4-77-0276).

Test No.: ____________ Date: ____________

Form A. GENERAL INFORMATION/ AMBIENT CONDITIONS

PROCESS UNIT

Manufacturer ____________; Model No.________; Serial No.________

Input Rating: ______BTU/HR

	START		FINISH	
Fuel Gas Meter Reading	______	cu ft	______	cu ft
Fuel Gas Pressure	______	in H_2O	______	in H_2O
Fuel Gas Temperature	______	^oF	______	^oF

Heating Value of Gas	______	BTU/Cu.Ft.
Ambient Temperature	______	^oF
Relative Humidity	______	%

Start Time ______

Finish Time ______

OPERATING CONDITIONS AND SECONDARY PARAMETERS DATA MEASURED DURING SAMPLING: ____

____

____

____

____

____

Test No.: ______________ Date: ___________

Form B. EMISSION MEASUREMENTS - Single Point Sampling

ANALYZER

Type ___________________; Manufacturer ____________________;

Model No.________________; Serial No. _____________________.

CONCENTRATION MEASUREMENTS O_2 - %; NOx - ppm; CO_2 - %

	O_2	NO_X	CO_2
First Five Minute Interval	_____	_____	_____
Second Five Minute Interval	_____	_____	_____
Third Five Minute Interval	_____	_____	_____
Fourth Five Minute Interval	_____	_____	_____
Fifth Five Minute Interval	_____	_____	_____
Sixth Five Minute Interval	_____	_____	_____
Average Concentration	_____	_____	_____

Test No.: ______________ Date: ____________

Form C. EMISSION MEASUREMENTS - Traverse Sampling

ANALYZER

Type________; Manufacturer__________; Model No._______; Serial No._______

CONCENTRATION MEASUREMENTS O_2 - %; NO_x - ppm; CO_2 - %

Point	O_2	NO_x	CO_2	Point	O_2	NO_x	CO_2
1	____	____	____	1	____	____	____
2	____	____	____	2	____	____	____
3	____	____	____	3	____	____	____

Average Concentrations:

O_2: _____ %

NOx: _____ ppm

CO_2: _____ %

Test No.: ____________ Date: __________

Form D. ANALYZER CALIBRATION CHECK AND DRIFT TEST.

ANALYZER

Type__________; Manufacturer_____________; Model No.________; Serial No._______

Range: ____________

Analyzer Calibration Data

	Cylinder Value (Indicate Units)	Analyzer Calibration Response (Indicate Units)	Absolute Difference (Indicate Units)	Difference (Percent of Range)
Zero Gas				
High-Range gas				

System Calibration Drift Data

	Initial Calibration Response (Indicate Units)	Final Calibration Response (Indicate Units)	Drift (Percent of Range)
Zero Gas			
High-Range gas			

$$\text{Drift} = \frac{(\text{Final Calibration Response} - \text{Initial Calibration Response})}{\text{Analyzer Range}} \times 100$$

Test No. ________ Date: ________

Form E. CORRECTION OF GAS CONCENTRATIONS DUE TO DRIFT

Gas	C_{avg}	C_o	C_{ma}	C_m	C_{gas}
O_2					
CO_2					
NOx					

Where:

C_{avg} = the average gas concentration as calculated by Form B or Form C.

C_o = the average of the initial and final system calibration drift check responses for the zero gas (refer to Form D).

C_{ma} = the actual (cylinder value) concentration of the upscale concentration gas (refer to Form D).

Cm = the average of the initial and final system calibration drift check responses for the upscale calibration gas (refer to Form D).

$$C_{gas} = (C_{avg} - C_o) \frac{Cma}{Cm - Co}$$

Test No.: ________________ Date: ____________

Form F. DETERMINATION OF HIGHER HEATING VALUE FROM GAS COMPOSITION ANALYSIS

Component	(1) Higher Heating Value at 60°F	(2) Mole Fraction	(1) x (2) Heating Value Contribution
Methane	1010 Btu/scf	________	________
Ethane	1770 Btu/scf	________	________
Propane	2520 Btu/scf	________	________
Butane(+)	3265 Btu/scf	________	________

Higher Heating Value of Fuel (Btu/scf) **TOTAL** ________

Test No.: ____________ Date: ____________

Form G. CORRECTION OF GAS METER READING AND DETERMINATION OF FIRING RATE

A. CORRECTION OF GAS METER READING

1.	Final Gas Meter Reading (Form A)	________	cu.ft.
2.	Initial Gas Meter Reading (Form A)	________	cu.ft.
3.	Uncorrected Volume of Gas Burned (Line 1 - Line 2)	________	cu.ft.
4.	Gas Pressure (Form A)*	________	in H_2O
5.	Barometric Pressure (Form A)	________	in Hg
6.	Pressure Correction to 29.92 in Hg is ((Line 5 + (Line 4 / 13.57)) / 29.92	________	No Units
7.	Gas Temperature (Form A)*	________	^{o}F
8.	Temperature Correction to $60^{o}F$ is: 519.7 / (Line 7 + 459.7)	________	No Units
9.	Meter Correction Factor (from Meter Calibration Curves)	________	No Units
10.	Corrected Volume of Gas Burned (Line 3 x Line 6 x Line 8 x Line 9)	________	scf

B. FIRING RATE

11.	Time of Burner Operation From Form A	________	minutes
12.	Heating Value of Fuel from Form A or Form F	________	BTU/scf
13.	Firing Rate Line 12 x Line 10 x (60/Line 11)	________	BTU/HR

* If initial and final values are different, record the average.

Test No.: ____________ Date: ____________

Form H. CALCULATION OF NOx EMISSION RATE USING THE OXYGEN BASED F-FACTOR

1. C_d is part per million NOx measured. Use the corrected average of the NOx readings from the sample points from Form E ________ ppm

2. b is volume percent O_2 measured. Use the corrected average of the NOx readings from the sample points from Form E ________ %

3. F_d is the oxygen based F-Factor, from tabulated values in 40 CFR 60, Appendix A, Method 19. Alternately, an F-Factor for mixed fuels may be derived if quality control procedures described in 40 CFR 60 Appendix A, Method 3B are followed. ________ $\frac{\text{dscf}}{\text{MMBtu}}$

4. E is the NOx Emission Rate

$$E = (1.195 \times 10^{-7}) \left[\frac{20.9}{(20.9 - b)} \right] (F_d) \ (C_d)$$

Substituting the corresponding line numbers gives

$$1.195 \times 10^{-7} \times \frac{20.9}{(20.9 - \text{Line } 2)} \times \text{Line } 1 \times \text{Line } 3$$ ________ lb/MMBtu

Test No.: ________________ Date: ______________

Form I. CALCULATION OF NOx EMISSION RATE USING THE CARBON DIOXIDE BASED F-FACTOR

1. C_d is part per million NOx measured. Use the corrected average of the NOx readings from the sample points from Form E ________ ppm

2. b is volume percent CO_2 measured. Use the corrected average of the NOx readings from the sample points from Form E ________ %

3. F_c is the CO_2 based F-Factor, from tabulated values in 40 CFR 60, Appendix A, Method 19. Alternately, an F-Factor for mixed fuels may be derived if quality control procedures described in 40 CFR 60 Appendix A, Method 3B are followed. ________ $\frac{\text{dscf}}{\text{MMBtu}}$

4. E is the NOx Emission Rate

$$E = (1.195 \times 10^{-7}) \left[\frac{100}{b} \right] (F_c) \; (C_d)$$

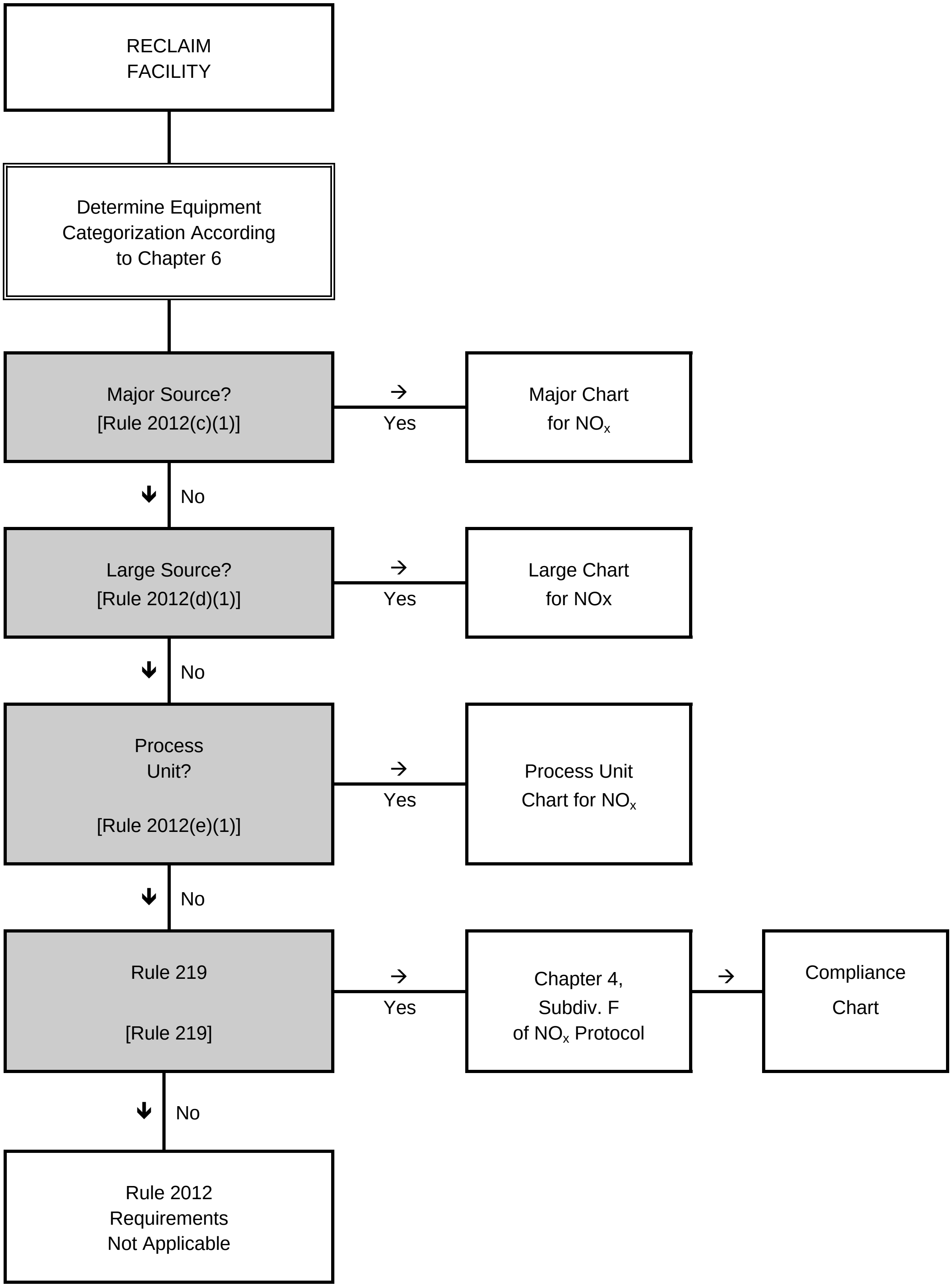
Substituting the corresponding line numbers gives

$$1.195 \times 10^{-7} \times \frac{100}{\text{Line } 2} \times \text{Line } 1 \times \text{Line } 3$$ ________ lb/MMBtu

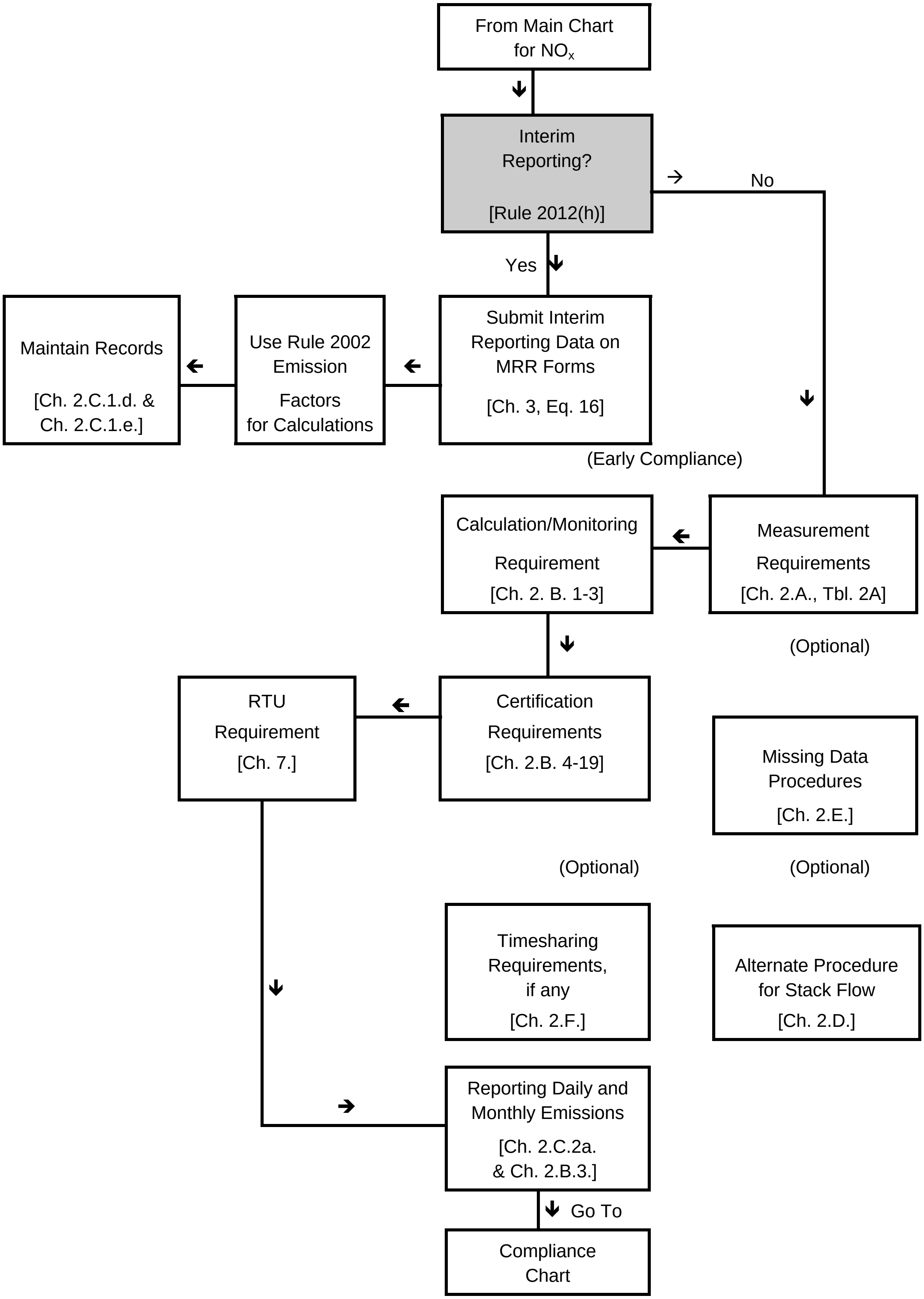
RULE 2012 PROTOCOL - APPENDIX A

Rule 2012 - Protocol for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NO_X) Emissions

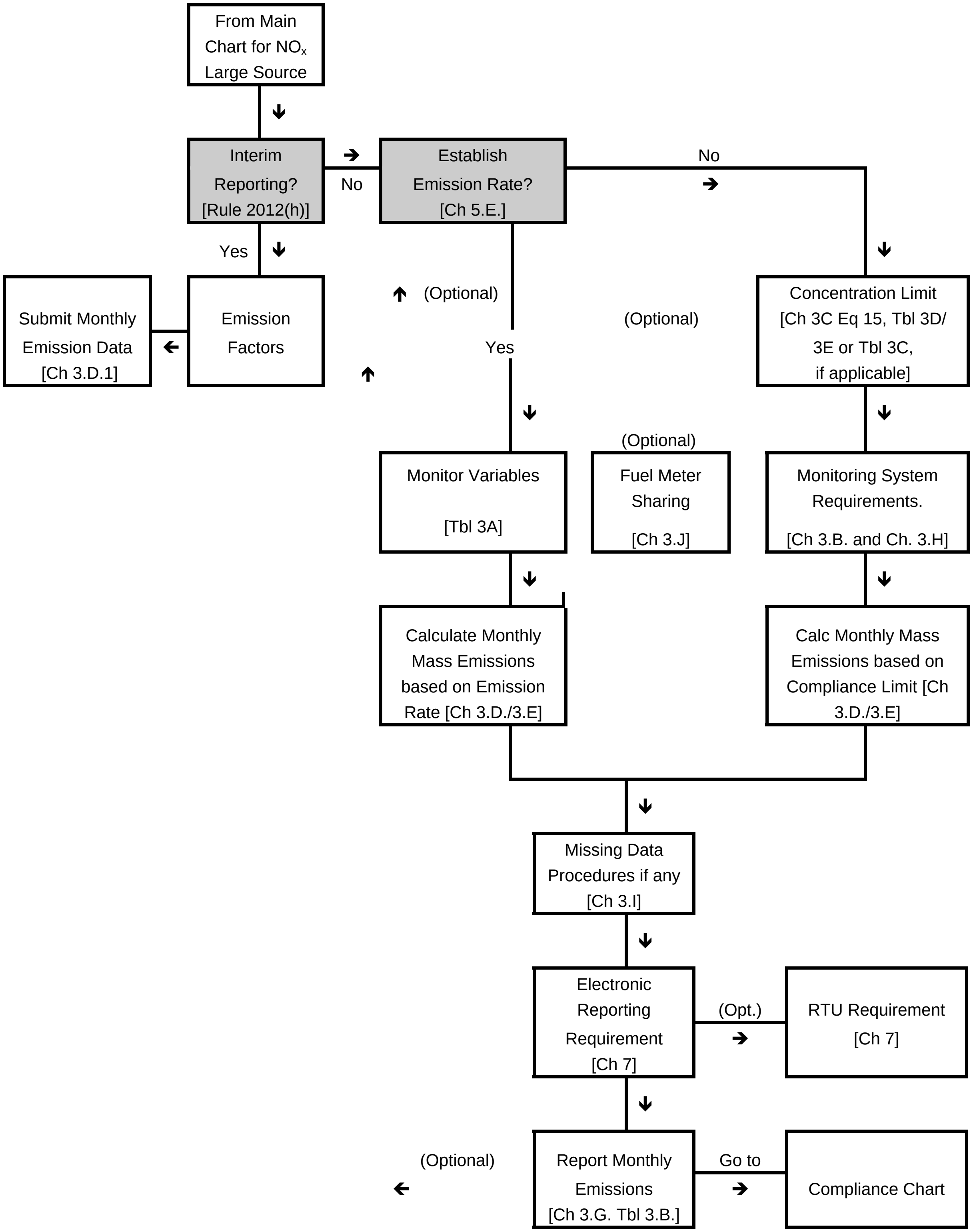
Main Chart for NO_x



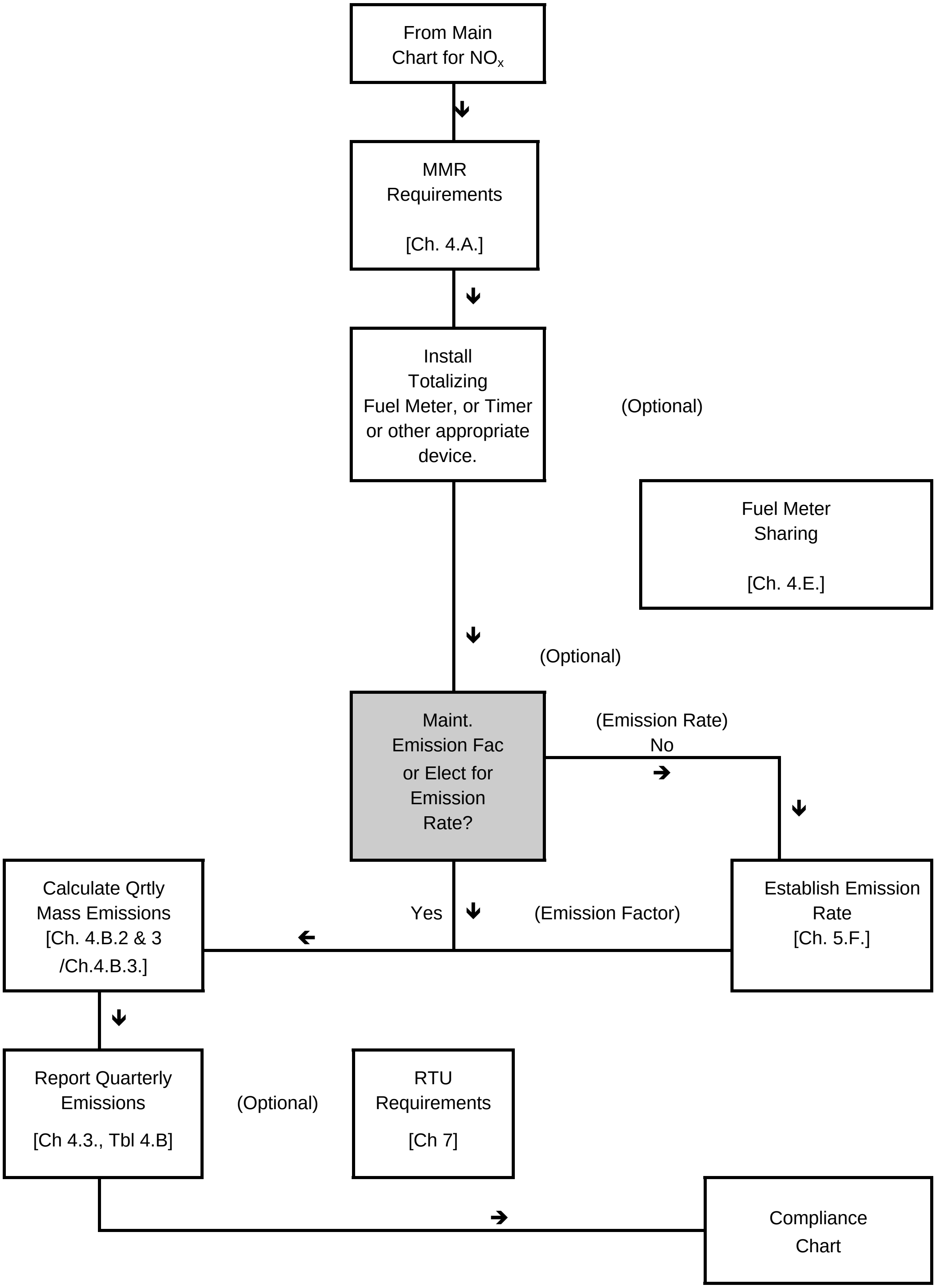
Major Chart for NO_x



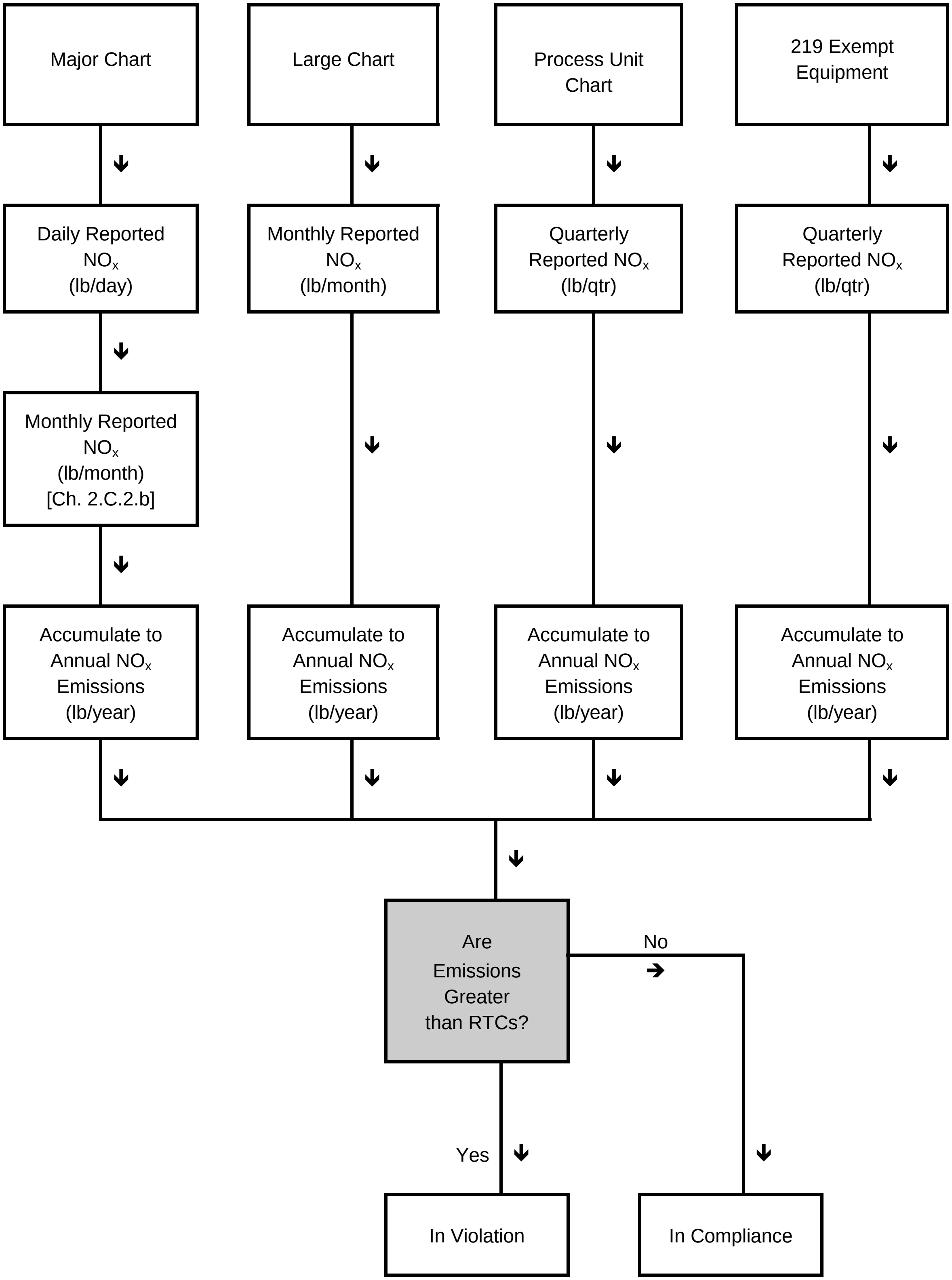
Large Chart For NO_x



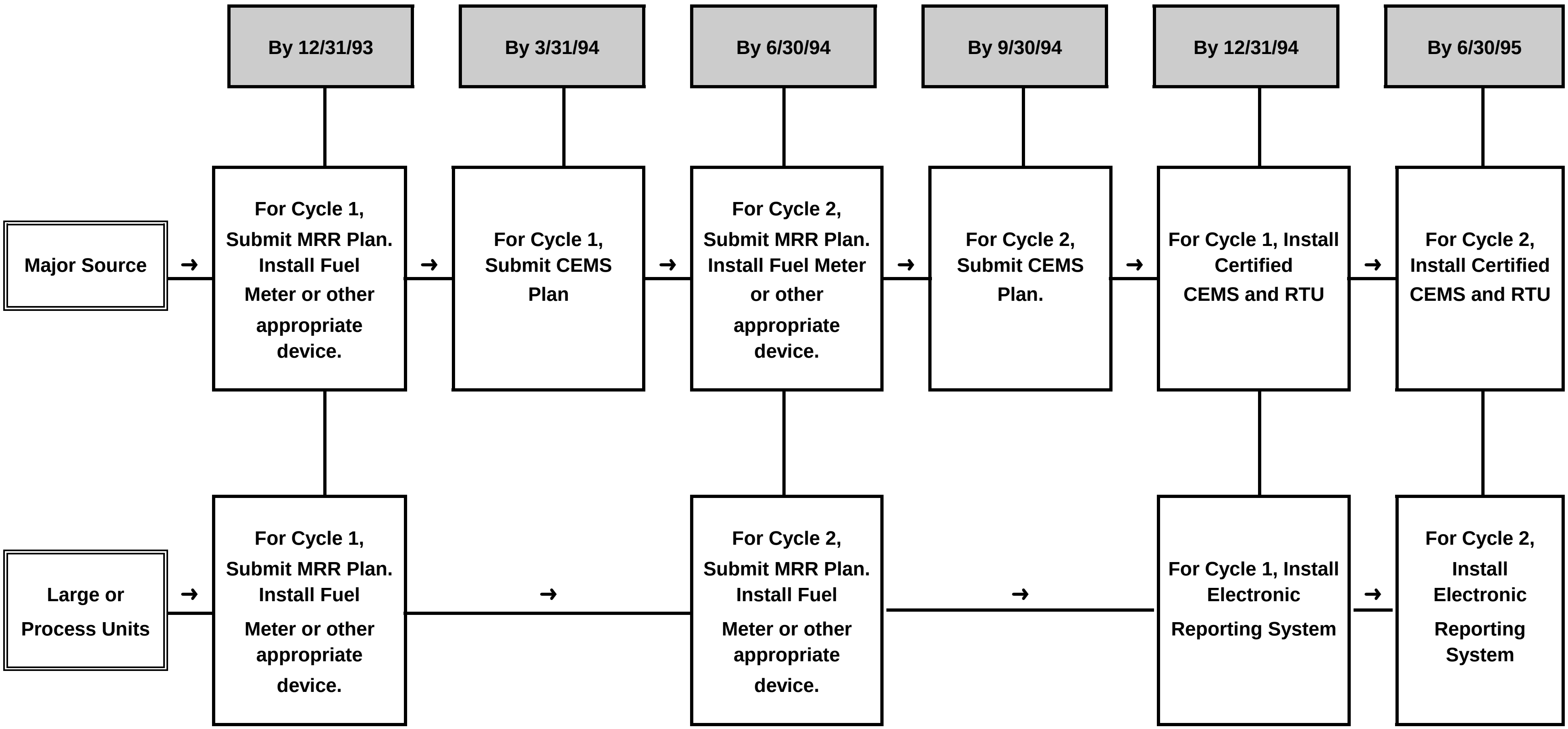
Process Unit Chart For NO_x



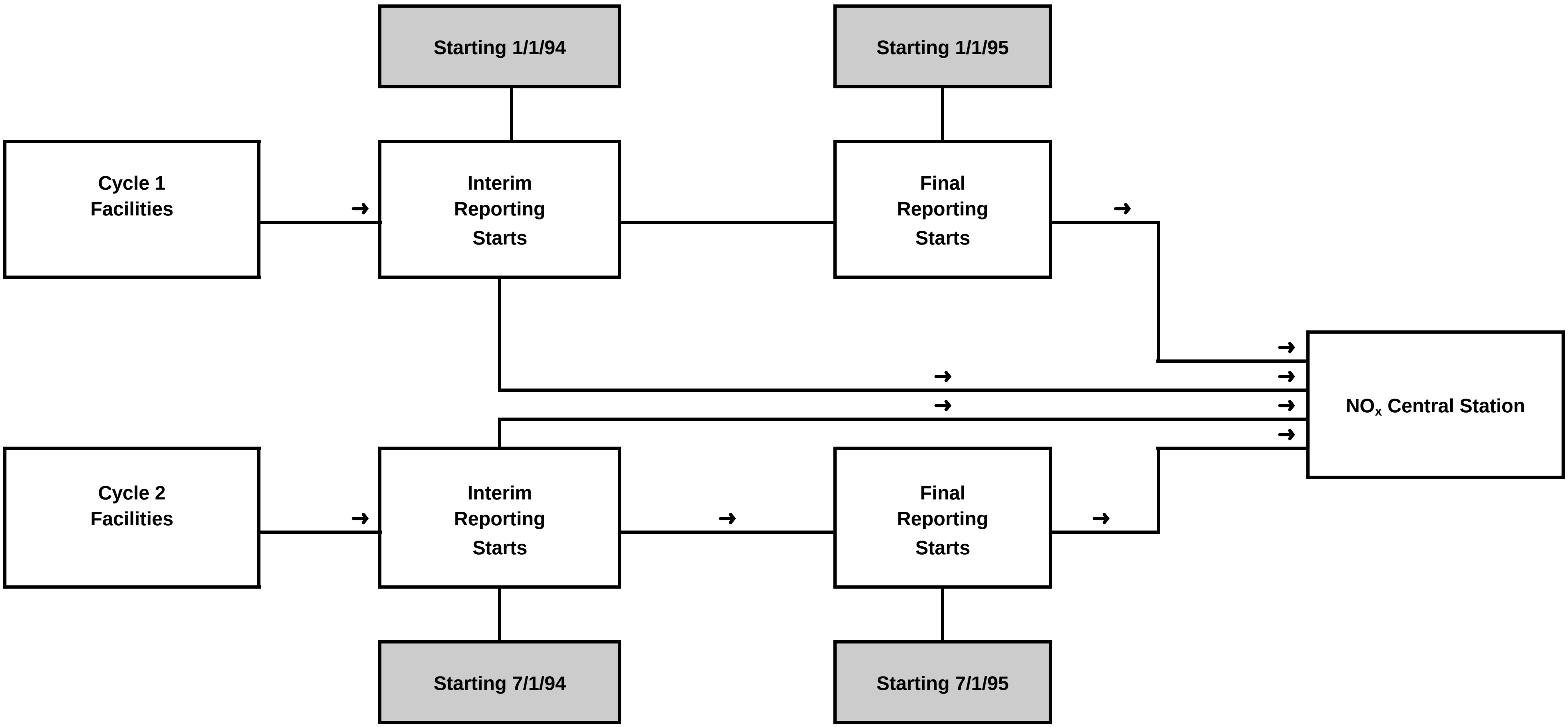
Compliance Chart For NO_x



NO_x Timeline Chart for Plan, Certification And Installation



Timeline For NO_x Emission Reporting



Note 1: The Facility Permit Holder shall submit a variance to the hearing board, if any of the deadlines are not met.

Note 2: Refer to Chapter 6 of NO_x Protocol for remedial actions required when the loss of categorization status occurs.

RULE 2012 PROTOCOL- CHAPTER 1

OVERVIEW

This document provides the technical specifications for normally operated RECLAIM sources subject to District Rule 2012 "Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NO_X) Emissions." District Rule 2012 divides sources into four categories - major sources, large sources, NO_X process units and equipment designated in Rule 219 - Equipment Not Requiring A Written Permit Pursuant To Regulation II. One difference in requirements between these source categories is the monitoring approach. A major source shall be monitored by a continuous emissions monitoring system (CEMS) or alternative monitoring system; a large source has the option to be monitored by a continuous process monitoring system (CPMS); and a NO_X process unit has the option to be monitored manually by a fuel meter and/or timer, and any other device specified by the Executive Officer, in accordance with approval criteria stated in Rule 2012.

Another distinction between major and large sources and process units is the way in which they transmit data to the District's Central Station and the reporting frequency. Major sources shall electronically transmit the data via an RTU on a daily basis. In addition, the aggregated NO_X emissions from all major sources shall be submitted in a Monthly Emissions Report. Large sources and process units must report data via the RTU or other acceptable approaches such as a modem. Large sources report monthly; all RECLAIM NOx Sources shall submit emission data as part of the Quarterly Certification of Emissions required by Rule 2004 - Requirements.

The criteria for determining the applicable NO_X RECLAIM category is presented in Table 1-A for a major source, Table 1-B for a large source, and Table 1-C for a NO_X process unit. A fourth class of NO_X sources are those that are exempt from permits per Rule 219. For both NO_X process units and equipment exempt under Rule 219, the Facility Permit holder shall report the NO_X emissions in the Quarterly Certification of Emissions . Election conditions for large sources and process units based on a NO_X emission factor, concentration limit or emission rate would be part of an amendment to the Facility Permit. Election conditions for process units based on category-specific emission rate shall also require an amendment to the Facility Permit.

The Facility Permit will limit mass emissions in accordance with the following:

$$\sum E_{CEMS} + \sum E_{CL} + \sum E_{ER} + \sum E_{EF} + \sum E_{219} \leq \text{RTCs}$$

where:

$\sum E_{CEMS}$	=	sum of facility emissions monitored by CEMS or alternative monitoring system
$\sum E_{CL}$	=	sum of facility emissions from large sources subject to concentration limits
$\sum E_{ER}$	=	sum of facility emissions from large sources and process units subject to emission rates
$\sum E_{EF}$	=	sum of facility emissions from large sources* and process units subject to emission factors
$\sum E_{219}$	=	sum of facility emissions from equipment exempt under Rule 219

RTC = RECLAIM Trading Credit held by the Facility Permit holder

The fuel usage, production rate, processing feed rate, or operating time for any large source, process unit, or equipment exempt under Rule 219 shall not exceed the value determined in accordance with the following relationship:

$$\Sigma\,(FxEF)_{pu,l} + \Sigma\,(FxER)_{pu,l} + \Sigma\,(FxEF)_{219} \leq RTC - \Sigma\,E_{CEMS} - \Sigma\,E_{CL}$$

where:

F = Fuel usage, production rate, processing feed rate, or operating time for the large source, process unit, or equipment exempt under Rule 219

The Facility Permit holder shall document the duration of operating time of any rental equipment or equipment operated by a contractor at the RECLAIM facility. Emissions generated at the RECLAIM facility by either rental equipment or equipment not listed or required to be listed under the Facility Permit and operated by a contractor, which exceeds 72 hours of operation in a quarter, shall be determined and reported by the Facility Permit holder according to the applicable methodology for major or large sources or process units or Rule 219 exempt equipment.

The duration of operating time and emissions from equipment operated by contractors need not be monitored or reported if the equipment is exclusively used for the following purposes that do not contribute to the manufacturing process:

- Landscaping and grounds maintenance;
- Maintenance and repair of structure, equipment, and their appurtenances;
- Construction and demolition; or
- Environmental investigation, testing, and remediation.

A Facility Permit holder subject to the requirements of Rules 2005(b)(2) and 2005(f) shall monitor and report applicable emissions as specified in Rule 2005(b)(2)(C). The emissions from these activities shall be determined according to the methodology specified for process units.

Emissions resulting from equipment during breakdowns shall be quantified in a manner specified by the Executive Officer in accordance with the following criteria:

1. When emissions are within the valid monitoring range of the monitor, the emissions shall be calculated based on the methodology pursuant to Chapters 2 and 3.
2. When emissions exceed the valid monitoring range of the monitor, the emissions may be calculated based on any one or more of the following:
    - Source test data
    - Fuel flow or throughput
    - Emission factor
    - Control efficiencies

This document has been divided into chapters addressing the various compliance aspects of Rule 2012. A summary of these chapters follows:

CHAPTERS 2 AND 3: MAJOR (CEMS) AND LARGE (CPMS) SOURCES

Chapters 2 and 3 describe the methodologies for measuring and reporting emissions from major and large sources, respectively. If a major source category is applicable then the Facility Permit holder shall be required to comply with the performance standards associated with a CEMS or an approved alternative monitoring system.

For large sources, the Facility Permit holder shall use a CEMS or elect to use a CPMS to measure NO_X emissions. With a CPMS, the focal point for determining NO_X emissions in this source category shall be the emission factor, concentration limit, or equipment-specific emission rate. In its most simplistic form, mass emissions shall be estimated by using the emission factor* (e.g., lb/mmscf), emission rate (e.g., lb/mmBtu), or concentration limit (e.g., ppmv converted to lb/mmBtu) and a throughput rate (typically fuel consumption adjusted for heating value).

Unless specifically exempted by Rule 2012, the Facility Permit holder for a major source shall measure and record all applicable measured variables as specified in Table 2-A. The Facility Permit holder for a large source shall measure and record one or more measured variables as specified in Table 3-A.

For large sources, process units and Rule 219 equipment, measurement and reporting requirements apply to variables used to calculate the NO_X emissions. The Facility Permit will specify either a concentration limit or an emission rate for a large source, in accordance with Rule 2012. One or more measured variables necessary to substantiate the equipment specific emission rate shall be monitored for large sources. Fuel usage or throughput is required to be measured for large sources subject to a concentration limit.

> * On and after January 1, 1995 (Cycle 1 facilities) and July 1, 1995 (Cycle 2 facilities), large-source emissions shall not be based on emission factors.

Several important aspects of Chapters 2 and 3 include:

- equations describing the methods used to calculate NO_X emissions
- operational requirements
- obtaining valid data points
- alternative data acquisition methods
- accuracy requirements
- quality assurance procedures
- missing data procedures
- final and interim reporting procedures, and
- time-sharing

The concentration limit for large sources plays an important role in assessing the equipment's compliance status. If a large source exceeds the applicable concentration limit then the equipment shall be in violation of District Rules. The methodology for determining the applicable concentration limit is covered in Chapters 3 and 5.

The protocol allows for election to a different monitoring classification by fuel usage. Dedicated fuel meters for major and large sources shall be required for fuel usage verification. The emission rate for large sources shall comply with source testing requirements specified in Chapter 6. Once approved by the Executive Officer, an emission rate serves as an "average" value representing the source's annual NO_X emissions.

CHAPTER 4: PROCESS UNITS- PERIODIC REPORTING AND RULE 219 EQUIPMENT

Chapter 4 describes the measuring and reporting requirements for the NO_X process unit category. NO_X process units, shall base emission calculations primarily on fuel consumption, processing rate, or operating time in conjunction with an emission factor or emission rate.

Important aspects of Chapter 4 include equations describing the method used to calculate NO_X emissions and reporting procedures, as well as determining NO_X emissions from equipment exempt under Rule 219.

CHAPTER 5: ALL SOURCES AND UNITS - SOURCE TESTING

Large sources shall require source testing to establish emission rates and concentration limits, and verify compliance with the concentration limit. Process units shall require source testing only to establish alternative emission rates. Chapter 5 presents a brief description of the required test methods and the required source testing and tune-up frequency for affected equipment.

CHAPTER 6: ALL SOURCES AND UNITS - DETERMINING SOURCE CATEGORY STATUS

As shown in Tables 1-A, 1-B, and 1-C all NO_X RECLAIM equipment are categorized by equipment rating, mass emissions and annual operating capacity. On that basis, Chapter 6 prescribes the methodology for assessing these criteria so that the RECLAIM Facility Permit holder can adequately categorize each piece of equipment.

CHAPTER 7 REMOTE TERMINAL UNITS (RTU) - ELECTRONIC REPORTING

Once the variables for determining emissions and tracking equipment operations have been measured, the measured data shall be stored at the facility. In addition, selected measured and calculated data shall be transmitted to the District's Central Station. This storing and transmitting of data shall be performed by the remote terminal unit (RTU) for a major source.

The use of a RTU for reporting purposes is optional for large sources, process units, and Rule 219 equipment.

Chapter 7 specifies tasks and characteristics required of the RTU as well as a guide for providing the required software/hardware for the RTU. In addition, this chapter serves as a:

- a functional guideline for operating requirements of the RTU, and
- an information source concerning RTU hardware/software procurement, configuration, installation, maintenance, and compatibility with the monitoring equipment and the District's Central Station.

TABLE 1-A

Criteria for Determining Major NO_X Source Category

- Any boiler, furnace, oven, dryer, heater, incinerator, test cell and any solid, liquid or gaseous fueled equipment with maximum rated capacity greater than or equal to 40 but less than 500 million Btu per hour and an annual heat input greater than 90 billion Btu per year; or 500 million Btu per hour or more irrespective of heat input;

- Any internal combustion engine with rated brake horsepower (bhp) greater than or equal to 1,000 bhp and operating more than 2,190 hours per year;

- Any gas turbine rated greater than or equal to 2.9 megawatts excluding emergency standby equipment or peaking unit;

- Any petroleum refinery fluid catalytic cracking unit;

- Any petroleum refinery tail gas unit;

- Any kiln or calciner with a rated process weight greater than or equal to 10 tons per hour and processing more than 21,900 tons per year;

- Any equipment burning or incinerating solid fuels or materials;

- Any existing equipment using NO_X CEMS or required to install CEMS under District rules to be implemented as of October 15, 1993;

- Any NOx source or process unit elected by the Facility Permit holder or required of the Executive Officer to be monitored with a CEMS;

- Any NO_X source or process unit for which NO_X emissions reported pursuant to Rule 301 were equal to or greater than 10 tons per yr for any calendar year from 1987 to 1991, inclusive, excluding NO_X sources or process units listed under Rule 2012 subparagraphs (d)(1)(A) through (d)(1)(E), and (e)(1)(A) through (e)(1)(D) and excluding any NO_X source or process unit which has reduced NO_X emissions to below 10 tons per year prior to January 1, 1994.

TABLE 1-B

Criteria for Determining Large NO_X Source Category

- Any boiler, furnace, oven, dryer, heater, incinerator, test cell and any liquid or gaseous fueled equipment with a maximum rated capacity greater than or equal to 40 but less than 500 million Btu per hour and an annual heat input of 90 billion Btu per year or less, or greater than or equal to 10 but less than 40 million Btu per hour and an annual heat input greater than 23 billion Btu per year;

- Any internal combustion engine with rated brake horsepower greater than or equal to 1,000 bhp and operating 2190 hours per year or less, or greater than or equal to 200 bhp but less than 1000 bhp and operating more than 2,190 hours per year;

- Any gas turbine rated greater than or equal to 0.2 but less than 2.9 megawatts, excluding any emergency standby equipment or peaking unit;

- Any kiln or calciner with rated process weight less than 10 tons per hour;

- Any sulfuric acid production unit;

- Any Facility Permit holder-selected NO_X process unit or equipment required by the Executive Officer to be monitored with a CPMS;

- Any NO_X source with reported emissions pursuant to Rule 301 equal to or greater than 4 tons per year, but less than 10 tons per year for any calendar year from 1987 to 1991, inclusive, excluding NO_X sources or process units listed under Rule 2012 subparagraphs (c)(1)(A) through (c)(1)(H), and (e)(1)(A) through (e)(1)(D).

TABLE 1-C

Criteria for Determining NO_X Process Unit Category

- Any boiler, furnace, oven, dryer, heater, incinerator, test cell and any liquid or gaseous fueled equipment with maximum rated capacity greater than or equal to 10 but less than 40 million Btu per hour and an annual heat input of 23 billion Btu per year or less; or greater than or equal to 2 but less than 10 million Btu per hour;

- Any internal combustion engine with rated brake horsepower greater than or equal to 200 bhp but less than 1000 bhp and operating 2,190 hours per year or less; or greater than 50 but less than 200 bhp;

- Any portable combustion and process equipment which is not a major or large source;

- Any emergency standby equipment or peaking unit;

- Any other NO_X source that is not a large or major NO_X source, or exempt pursuant to Rule 219 - "Equipment Not Requiring a Written Permit Pursuant to Regulation II".

RULE 2012 PROTOCOL
CHAPTER 2

MAJOR SOURCES - CONTINUOUS EMISSION MONITORING SYSTEM (CEMS)

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CHAPTER 2 - MAJOR SOURCES - CONTINUOUS EMISSION MONITORING SYSTEM (CEMS)

Between January 1, 1994 and December 31, 1994 (Cycle 1 facilities) and between July 1, 1994 and June 30, 1995 (Cycle 2 facilities), major sources shall be allowed to use an interim reporting procedure to measure and record NOx emissions on a monthly basis according to the requirements specified in Chapter 3 "Large Sources - Continuous Process Monitoring System (CPMS)" or by extracting NO_X emission data from existing District certified continuous emissions monitoring system (CEMS). Chapter 2, Subdivision C, Paragraph 1 specifies the requirements for this interim period. On and after January 1, 1995 (Cycle 1 facilities) and July 1,1995 (Cycle 2 facilities), the Facility Permit holder of each major source shall report the daily NOx emissions by 5:00 p.m. of the following day and comply with all other applicable requirements (except Chapter 2, Subdivision C, Paragraph 1) specified in this chapter.

The Facility Permit holder of a source that is required to install CEMS may request the Executive Officer to approve an alternative monitoring device (or system components) to quantify the emissions of NO_X. The applicant shall demonstrate to the Executive Officer that the proposed alternative monitoring device is at a minimum equivalent in relative accuracy, precision, reliability, and timeliness to a CEMS for that source, according to the criteria specified in 40 CFR Part 75 Subpart E. In lieu of the criteria specified in 40 CFR Part 75 Subpart E, substitute criteria is acceptable if the applicant demonstrates to the Executive Officer that the proposed alternative monitoring device is at minimum equivalent in relative accuracy precision, reliability, and timeliness to a CEMS for that source. Upon approval by the Executive Officer, the substitute criteria shall be submitted to the federal Environmental Protection Agency as an amendment to the State Implementation Plan (SIP).

A. MEASUREMENT REQUIREMENTS

1. The Facility Permit holder of each major NO_x equipment shall install, calibrate, maintain, and operate an approved CEMS to measure and record the following:

    a. Nitrogen oxide concentrations in the gases discharged to the atmosphere from affected equipment;

    b. Oxygen concentrations, at each location where nitrogen oxide concentrations are monitored, if required for calculation of the stack gas flow rate;

    c. Stack gas volumetric flow rate. An in-stack flow meter may be used to determine mass emissions to the atmosphere from affected equipment, except:

        i. when more than one affected piece of equipment vents to the atmosphere through a single stack and there is no approvable means of determining emissions from each piece of equipment; or

ii. during periods of low flow rates when the flow rate is no longer within the applicable range of the in-stack flow meter.

d. In lieu of complying with Chapter 2, Subdivision A, Paragraph 1, Subparagraph c, the Facility Permit holder shall calculate stack gas volumetric flowrate using one of the following alternate methods:

i. Heat Input

If heat input rate is needed to determine the stack gas volumetric flow rate, the Facility Permit holder shall include in the CEMS calculations the F_d factors listed in 40 CFR Part 60, Appendix A, Method 19, Table 19-1. The Facility Permit holder shall submit data to develop F factors when alternative fuels are fired and obtain the approval of the Executive Officer for use of the F factors before firing any alternative fuel,

ii. Oxygen Mass Balance

Flow rate can be determined using oxygen mass balance as approved through a plan submitted to and approved by the Executive Officer, or

iii. Nitrogen Mass Balance

Flow rate can be determined using nitrogen mass balance as approved through a plan submitted to and approved by the Executive Officer.

The Facility Permit holder shall measure and record all variables necessary for the method chosen to calculate stack gas volumetric flowrate.

e. All applicable variables listed in Table 2-A.

f. The Facility Permit holder shall also provide any other data necessary for calculating air contaminant emission rates as determined by the Executive Officer.

g. The data generated from a monitoring system for parameters listed in subparagraphs a, b, c and d of Chapter 2, Subdivision A, Paragraph 1 shall be recorded by both (1) the remote terminal unit (RTU) and (2) strip chart recorder or electronic recorder. The RTU shall be capable of producing a printout of the stored data upon request from the Executive Officer or designee. The strip chart recorder or alternative electronic recorder shall be located in parallel to the RTU. The strip chart recorder or alternative electronic recorder shall receive data independent of the RTU and serve as an independent tool for verifying data archived in the RTU or sent to the District Central NOx Station.

If a strip chart recorder is used, the strip chart shall have a minimum chart width of 10 inches, a readability of 0.5% of the span, and a minimum of 100 chart divisions. Alternatively, if an electronic recorder is used, the recorder shall be capable of writing data on a medium that is secure and tamper-proof. Possible media include, but are not limited to, "write-once-read-many" type or a data encryption system that does not permit encrypted data files to be altered after they have been created, without making the data inaccessible through standard vendor-provided decryption software, or without leaving traceable evidence of tampering. Also, at a minimum, the real-time sampling frequency of the electronic recorder shall be equal to or greater than the rate of data collection for the RTU. Furthermore, such recorded data shall be readily accessible upon request by the Executive Officer or designee. If software is required to access the recorded data, a copy of the software, and all subsequent revisions, shall be provided to the Executive Officer or designee at no cost. If a device is required to retrieve and provide a copy of such recorded data upon request to the Executive Officer or designee, the Facility Permit holder shall maintain and operate such a device at the facility.

The Facility Permit holder shall specify within the CEMS application, as required under Chapter 2, Subdivision A, Paragraph 2, the type of data recording system to be used in parallel to the RTU.

2. The Facility Permit holder shall by March 31, 1994 for Cycle 1 facilities and September 30, 1994 for Cycle 2 facilities, submit a CEMS plan to the Executive Officer for approval. The plan shall contain at a minimum the following items:

   a. A list of all major sources which will have CEMS installed.

   b. Details of the proposed Continuous Emission Monitors as well as the proposed flow monitors for each affected source.

   c. Details of the Quality Control/Quality Assurance Plan for the CEMS.

d. Proposed range of each CEMS and the expected concentrations of pollutants for each source.

e. Date by which purchase order for each system will be issued.

f. Construction schedule for each system, and date of completion of installation.

g. Date by which CEMS certification test protocol will be submitted to the District for approval for each system.

h. Date by which certification tests will be completed for each system.

i. Date by which certification test results will be submitted for review by the District, for each system.

j. Any other pertinent information regarding the installation and certification for each system.

If a CEMS plan is disapproved in whole or in part, the District staff will notify the Facility Permit holder in writing and the Facility Permit holder shall have 30 days from the date it receives the notice from the District to resubmit its plan.

3. The variables listed in Table 2-A shall be measured and recorded at the facility to determine mass emission and track the operation of basic and control equipment. The variables listed in Table 2-B shall be reported to the District's NO_x Central Station Computer. Alternatives indicated in Tables 2-A and 2-B indicate choices which shall be specified in the Facility Permit for that equipment.

4. As part of the Facility Permit Application review, the Executive Officer may modify the list of Facility Permit holder-selected tracking variables.

5. Data on Facility Permit holder selected variables shall be made available to the District staff upon request.

6. Source tests shall be performed by testing firms/laboratories who have received approval from the District by going through the District's laboratory approval program.

7. All Relative Accuracy Test Audits (RATA) shall be performed by testing firms/laboratories who have received approval from the District by going through the District's laboratory approval program.

B. MONITORING SYSTEMS

1. Information Required for Each 15-Minute Interval

All CEMS for affected equipment shall, at a minimum, generate and record the following data points once for each successive 15-minute period on the hour and at equally spaced intervals thereafter:

a. Nitrogen oxides concentration in the stack in units of ppmv;

b. Oxygen concentration or carbon dioxide concentration in the stack in units of percent;

c. Volumetric flow rate of stack gases in units of dry or wet standard cubic feet per hour (dscfh or wscfh). For affected equipment standard gas conditions are defined as a temperature at 68°F and one atmosphere of pressure;

d. (i) Fuel flow rates in units of standard cubic feet per hour (scfh) for gaseous fuels or pounds per hour (lb/hr) for liquid fuels if EPA Method 19 is used to calculate the stack gas volumetric flow rate, and

(ii) Fuel type;

e. Nitrogen oxide mass emission in units of lb/hour. The nitrogen oxide mass emissions is calculated according to the following:

$$e_i = a_i \times c_i \times 1.195 \times 10^{-7} \qquad \text{(Eq. 1)}$$

where:

e_i = The mass emissions of nitrogen oxides in pounds per hour.

a_i = The stack gas concentration of nitrogen oxides (ppmv).

c_i = The stack gas volumetric flow rate (scfh).

Example Calculation:

$$a_i = 40 \text{ ppm}$$
$$c_i = 150{,}000 \text{ scfh}$$
$$e_i = 40 \times 150{,}000 \times 1.195 \times 10^{-7}$$
$$e_i = 0.72 \text{ lb/hr}$$

When the CEMS uses the heat input rate and oxygen concentration to determine the nitrogen oxide mass emissions, the following equation shall be used to calculate the emissions of nitrogen oxides:

$$e_i = a_i \times [20.9/(20.9 - b_i)] \times 1.195 \times 10^{-7} \times \sum_{j=1}^{r} (F_{dij} \times d_{ij} \times V_{ij}) \qquad \text{(Eq. 2)}$$

where:

e_i	=	The mass emissions of nitrogen oxides in pounds per hour
ai	=	The stack gas concentration of nitrogen oxides (ppmv)
bi	=	The stack gas concentrations of oxygen (%)
r	=	The number of different types of fuel
F_{dij}	=	The oxygen-based dry F factor for each type of fuel, the ratio of the gas volume of the products of combustion to the heat content of the fuel (scf/106 Btu)
dij	=	The fuel flow rate for each type of fuel measured every 15-minute period
Vij	=	The higher heating value of the fuel for each type of fuel

The product (d_{ij} x V_{ij}) shall have units of millions of Btu per hour (10^6 Btu/hr).

Equation 2 may not be used in cases where enriched oxygen is used, non-fuel sources of carbon dioxide are present (e.g., lime kilns and calciners), and the oxygen content of the stack gas is 19 percent or greater.

<u>Example Calculation:</u>

a_i = 40 ppm
b_i = 3.5%

F_{dij} = 8710 dscf/10^6 Btu
d_{ij} = 5,000 dscf
V_{ij} = 1050 Btu/scf or 1050 mmBtu/mmscf

$$e_i = a_i \times [20.9/(20.9 - b_i)] \times 1.195 \times 10^{-7} \times \sum_{j=1}^{r} (F_{dij} \times d_{ij} \times V_{ij})$$

e_i = 40 x [20.9/(20.9 - 3.5)] x 1.195 x 10^{-7} x [8710/10^6 x 5000 x 1050]
e_i = 0.26 lb/hr

When the CEMS uses the heat input rate and carbon dioxide concentration to determine the nitrogen oxide mass emissions, the following equation shall be used to calculate the emissions of nitrogen oxides:

$$e_i = (a_{i/ti}) \times 100 \times 1.195 \times 10^{-7} \times \sum_{j=1}^{r} (F_{cij} \times d_{ij} \times V_{ij}) \qquad \text{(Eq. 3)}$$

where:

e_i = The mass emissions of nitrogen oxides in pounds per hour.
a_i = The stack gas concentration of nitrogen oxides (ppmv).
t_i = The stack gas concentrations of carbon dioxide (%).
r = The number of different types of fuel.
F_{cij} = The carbon dioxide-based dry F factor for each type of fuel, the ratio of the dry gas volume of carbon dioxide to the heat content of the fuel (scf/10^6 Btu).
dij = The fuel flow rate for each type of fuel measured every 15-minute period.
V_{ij} = The higher heating value of the fuel for each type of fuel.

The product (d_{ij} x V_{ij}) shall have units of millions of Btu per hour (10^6 Btu/hr).

Example Calculation:

a_i	=	40 ppm
ti	=	11.0%
F_{cij}	=	1040 scf/10^6 Btu
dij	=	5,000 dscf
Vij	=	1050 Btu/scf or 1050 mmBtu/mmscf

$$ei = ai/ti \times 100 \times 1.195 \times 10^{-7} \times \sum_{j=1}^{r} (Fcij \times dij \times Vij)$$

$$ei = 40/11.0 \times 100 \times 1.195 \times 10^{-7} \times [1040 \times 5000 \times 1050 \times 10^{-6}]$$

$$ei = 0.24 \text{ lb/hr}$$

f. All measurements for concentrations and stack gas flow rates, and selection of F factor shall be made on a consistent wet or dry basis.

g. CEMS status. The following status codes shall be used to report the CEMS status:

1-1 VALID DATA

2-2 CALIBRATION

3-3 OFF LINE

4-4 ALTERNATE DATA ACQUISITION (e.g., manual sampling)

5-5 OUT OF CONTROL

6-6 FUEL SWITCH (e.g., gas to oil, coke to coal)

7-7 10% RANGE (may be used to report at default 10% valid range whenever actual concentration value is below 10%)

8-8 LOWER THAN 10% RANGE (may be used to report at actual concentration value if less than 10% valid range

9-9 NON-OPERATIONAL

h. For processes in which less than 50% of emissions are caused by fuel combustion, record the Source Classification Code (SCC) for the process conducted. SCCs are listed in the State of California Air Resources Board Document "Instructions for the Emission Data System Review and Update Report, Appendix III, Source Classification Codes and EPA Emission Factors".

i. the count of valid data points collected.

j. the count of data points in excess of 95% of span range of the monitor collected.

2. Hourly Calculations

The hourly average stack gas concentrations of nitrogen oxides and oxygen, the stack gas volumetric flow rate, the fuel flow rate and the emission rate of nitrogen oxides shall be calculated for each equipment as follows:

$$A = \frac{\sum_{i=1}^{n} a_i}{n} \quad \text{(for } NO_x \text{ concentration)} \qquad \text{(Eq. 4)}$$

$$B = \frac{\sum_{I=1}^{n} b_i}{n} \quad \text{(for } O_2 \text{ concentration)} \qquad \text{(Eq. 5)}$$

$$C = \frac{\sum_{i=1}^{n} c_i}{n} \quad \text{(for stack gas volumetric flow rate)} \qquad \text{(Eq. 6)}$$

$$D_i = \frac{\sum_{i=1}^{n} d_i}{n} \quad \text{(for fuel flow rates)} \qquad \text{(Eq. 7)}$$

Calculate D for each type of fuel firing separately.

$$E_k = \frac{\sum_{i=1}^{n} e_i}{n} \quad \text{(for } NO_x \text{ emissions)} \qquad \text{(Eq. 8)}$$

All concentrations and stack gas flow rates shall be calculated on a consistent wet or dry basis.

where:

A = The hourly average stack gas concentration of nitrogen oxides (ppmv)

a_i = The measured stack gas concentrations of nitrogen oxides (ppmv)

B = The hourly average oxygen stack concentration (%)

b_i = The measured stack gas concentrations of oxygen (%)

C = The hourly average stack gas flow rate (dscfh)

c_i = The measured stack gas volumetric flow rates (dscfh)

D = The hourly average fuel flow rates, for each type of fuel (appropriate units of volumetric flow rate for each type of fuel, e.g., scfh, gal/hr, lb/hr, bbl/hr, liters/hr, etc.)

d_i = The measured fuel flow rates for each type of fuel (appropriate units of volumetric flow rate for each type of fuel, e.g., scfh, gal/hr, lb/hr, bbl/hr, etc.)

E_k = The hourly average emissions of nitrogen oxides (lb/hr)

e_i = The measured mass emissions of nitrogen oxides in pounds per hour

n = Number of valid data points during the hour

The values of A through E_k shall be recorded for each affected piece of equipment.

3. Daily Calculations

a. Daily mass emissions calculation

The daily emissions of nitrogen oxides shall be calculated and recorded for each affected NO_x source using the following procedure:

$$G = \sum_{k=1}^{N} E_k + \sum_{m=1}^{P} E_m + \sum_{o=1}^{Q} E_{st} + \sum_{r=1}^{S} E_{sh} \quad \text{(Eq. 9)}$$

where:

G = The daily emissions of nitrogen oxides (lb)

E_m = The hourly average emissions of nitrogen oxides using substitute data (see Chapter 2, Subdivision B, Paragraph 5, Subparagraph b and Chapter 2 Subdivision F)(lb/hr)

E_k = The hourly average emissions of nitrogen oxides using data recorded by CEMS (lbs/hr)

E_{st} = The hourly average emissions of nitrogen oxides during startup (lb/hr) (see Chapter 2 Subdivision G)

E_{sh} = The hourly average emissions of nitrogen oxides during shutdown (lbs/hr) (see Chapter 2 Subdivision G)

N = Number of hours of valid data (see Chapter 2, Subdivision B, Paragraph 5) from the CEMS coinciding with the source operating hours

P = Number of hours using substitute data when the source is operating

Q = The number of hours during startup period

S = The number of hours during shutdown period

and,

M = Number of hours during the day.

Note that: $M = N + P + Q + S = 24$ hours.

Example Calculation:

E_k	= 0.5 lb/hr	E_{st}	= 0 lb/hr	Q	= 0 hr
E_m	= 0.7 lb/hr	E_{sd}	= 0 lb/hr	S	= 0 hr
N	= 21 hr				
P	= 3 hr				
M	= 24 hr				
G	= (0.5 lb/hr)(21 hr) + (0.7 lb/hr)(3 hr) + (0 lb/hr)(0 hr)+ (0 lb/hr)(0 hr)				
G	= 10.5 + 2.1 = 12.6 lb				

4. Operational Requirements

The CEMS shall be operated and data recorded at all times except for CEMS breakdowns and repairs. Calibration data shall be recorded during zero and span calibration checks, and zero and span adjustments. For periods of hot standby the Facility Permit holder may enter a default value for NO_x emissions. Before using any default values the Facility Permit holder shall obtain the approval of the Executive Officer and must include in the CEMS applications or CEMS plans the estimates of NO_x emissions, the NO_x concentrations, the oxygen concentrations, and the fuel input rates or the stack gas volumetric flow rates during hot standby conditions. The Executive Officer will disapprove those emission values which do not correspond to hot standby conditions.

5. Requirements for Valid Data Points

Valid data points are data points from a CEMS which meets the requirements of Chapter 2, Subdivision B, Paragraph 13, and which is not out-of-control as defined in Attachment C - Quality Assurance and Quality Control Procedures. In addition, whenever specifically allowed by these RECLAIM rules, data points obtained by the methods specified in Chapter 2, Subdivision B, Paragraph 6 and Chapter 2, Subdivision B, Paragraph 7, are considered valid. Furthermore, a data point gathered by a certified CEMS except a zero value data point, shall not be valid unless it meets the requirements of Chapter 2, Subdivision B, Subparagraph (8)(a). A zero value data point is a data point gathered while the source is not operating and is within 5% of the span range from zero value.

a. Each CEMS and component thereof shall be capable of completing a minimum of one cycle of operation (sampling, analyzing and data recording) for each successive 15-minute interval.

b. Raw data shall be gathered from the monitors at equally spaced intervals. The Facility Permit holder shall specify, within the test report for a Relative Accuracy Test Audit of a CEMS, the frequency of data gathering in a 15-minute interval. This data gathering frequency shall remain the same throughout the period following the Relative Accuracy Test Audit until a subsequent Relative Accuracy Test Audit is conducted with a different specified frequency. The specified frequency shall be the frequency for data gathering to constitute continuous measurement.

c. All valid raw data points gathered from the monitors within a 15-minute interval shall be used to compute a 15-minute average emissions data point. If only one valid data point is gathered within a 15-minute interval, that data point shall be used as the 15-minute average emission data point. No invalid data points may be used to compute the 15-minute average emission data point. A valid 15-minute average emission data point must further be based on a minimum of one valid raw data point.

d. Except for facilities which are required to comply with 40 CFR Part 75, the following data for each 15-minute period shall be computed for each CEMS:
   i. the average emissions values,
   ii. the count of valid data points, and
   iii. the count of data points in excess of 95% of span range of the monitor.

e. All NO_x concentration, volumetric flow, and NO_x emission rate data shall be reduced to 1 hour averages. Valid hour averages shall be equally computed based on four valid 15-minute average emission data points equally spaced over each 1 hour period, commencing at 12:00 a.m., except for a maximum of four 1-hour maintenance periods in each day during which CEMS maintenance activities such as calibration, quality assurance, maintenance, or CEMS repair is conducted. During these 1-hour maintenance periods a valid hour average shall consist of at least two valid 15-minute average emission data points. A 1-hour maintenance period is defined when the operation of the CEMS is interrupted for CEMS maintenance activities at any time during any 1-hour period, and that period shall count towards the four 1-hour maintenance periods allowed regardless of the number of valid data points gathered. The CEMS shall be kept properly operational at all times unless such CEMS must be turned off for CEMS maintenance activities.

f. Failure of the CEMS to acquire the required number of valid 15-minute average emission data points within any 1-hour period shall result in the loss of such data for the entire 1-hour period and the Facility Permit holder shall record and report data by means of the data acquisition and handling system for the missing hour in accordance with the applicable procedures for substituting missing data in the Missing Data Procedures in Chapter 2 Subdivision E of this document.

6. Alternative Data Acquisition Using Reference Methods

a. When valid nitrogen oxides emission data is not collected by the permanently installed CEMS, emission rate data may be obtained using District Methods 7.1 or 100.1 (for NO_x concentration in the stack gas) in conjunction with District Methods 1.1, 2.1, 3.1, and 4.1 or by using District Methods 7.1 or 100.1 in conjunction with District Method 3.1 and EPA Method 19. For District Method 7.1 a minimum of 12 samples, equally spaced over a one-hour period, shall be taken. Each sample shall represent the five-minute period in which it was taken.

b. If the Facility Permit holder chooses to use a standby CEMS (such as in a mobile van or other configuration), to obtain alternative monitoring data at such times when the permanently installed CEMS for the affected source(s) cannot produce valid data, then the standby CEMS is subject to the following requirements:

i. Standby CEMS shall be equivalent in relative accuracy, reliability, reproducibility and timeliness to the corresponding permanently installed CEMS.

ii. The Facility Permit holder shall submit a standby CEMS plan to the District for review prior to using the standby CEMS.

iii. District acceptance of standby CEMS data shall be contingent on District approval of the plan.

iv. The use of standby CEMS shall be limited to a total of 6 months for any source(s) within a calendar year.

v. The Facility Permit holder shall notify the District within 24 hours if the standby CEMS is to be used in place of the permanently installed CEMS.

vi. During the first 30 days of standby CEMS use, the Facility Permit holder shall conduct a Certified Gas Audit (CGA) of the standby CEMS.

vii. The Facility Permit holder shall notify the District within the 30-day period if the standby CEMS shall be used longer than 30 days.

viii. After the first 30 days of using the standby CEMS , the Facility Permit holder shall conduct at least one RATA of the standby CEMS and the RATA shall be conducted within 90 days of the initial use of the standby CEMS.

ix. All RATA and certification tests shall be performed by testing firms/laboratories who have received approval from the District by going through the District's laboratory approval program.

x. Immediately prior to obtaining data from the source(s) to be monitored, the standby CEMS shall be quality assured in accordance with District Method 100.1

7. Alternative Data Acquisition Using Process Curves or Other Means

Process curves of NO_x emission rates or other alternative means of NO_x emission rate data generation may be used to obtain nitrogen oxides emission data, provided the Facility Permit holder has obtained the approval of the Executive Officer prior to using alternate means of NO_x emission rate data generation. The process curves and the alternate means of NO_x emission data generation mentioned in this paragraph shall not be used more than 72 hours per calendar month and may only be used if no CEMS data or reference method data gathered under Chapter 2, Subdivision B, Paragraph 6 is available. Process curves may be used on units which have air pollution control devices for the control of NO_x emissions provided the Facility Permit holder submits a complete list of operating conditions that characterize the permitted operation. The conditions will be specified in the Facility Permit for that equipment. The process variables specified in the Facility Permit conditions shall be monitored by the source.

8. Span Range Requirements for NOx Analyzers and O_2 Analyzers

a. Full scale span ranges for the NO_x analyzers and O_2 analyzers used as part of a stack gas volumetric flow system at each source shall be set on an individual basis. The full scale span range of the NO_x analyzers and O_2 analyzers shall be set so that all data points gathered by the CEMS lie within 10 - 95 percent of the full scale span range. However, any data points that fall below 10 percent of the full scale span range may be reported in accordance with 8(b), 8(c), or 8(d) as applicable. Missing Data Procedures as prescribed in Chapter 2, Subdivision E shall be substituted for any data points falling above 95 percent range of the full scale span range.

b. For CEMS with RECLAIM certified multiple span ranges, the Facility Permit holder shall report data that falls below 10 percent of the higher full scale span range and above 95 percent of the lower full scale span range, at the 10 percent value of the higher full scale span range.

c. In the event that any data points gathered by the CEMS fall below 10 percent of the full scale span range, the Facility Permit holder may elect to report NO_x concentrations at the 10 percent span range value.

d. In the event that any data points gathered by the CEMS fall below 10 percent of the lowest vendor guaranteed full scale span for that CEMS (defined as the lowest full scale span range that the vendor guarantees to be capable of meeting all current certification requirements of RECLAIM in Rule 2012 Protocols, Appendix A), the Facility Permit holder may elect to use the following procedures to measure and report NO_x concentrations.

   i. Report all monitored concentrations that fall below 10 percent of the lowest vendor guaranteed full scale span range for that CEMS at the 10 percent lowest vendor guaranteed span range value, or

   ii. Report all monitored concentrations that fall below 10 percent of the lowest vendor guaranteed full scale span range for that CEMS at the actual measured value, provided that the CEMS meets the Alternative Performance Requirements prescribed in Attachment G.

   The Alternative Performance Requirements prescribed in Attachment G shall be imposed in place of the semiannual assessments as required pursuant to Attachment C (B)(2).

e. The Facility Permit holder electing to use (B)(8)(c) and (B)(8)(d)(i) to report NO_x concentrations that fall below 10 percent of full scale span range or 10 percent of the lowest vendor guaranteed full scale span range for that CEMS, shall meet the following:

i. In the event any of the specified testing requirements as prescribed in Attachment C (B)(2) are not met, the Facility Permit holder shall no longer use (B)(8)(c) or (B)(8)(d)(i) to report NO_x concentrations below 10 percent of the full scale span range until compliance is demonstrated. Missing Data Procedures specified in Chapter 2, Subdivision E shall apply retroactively from the date in which the Facility Permit holder last demonstrated compliance with Attachment C (B)(2).

ii. From September 8, 1995 to the beginning of the compliance year (January 1, 1995 for Cycle 1 and July 1, 1995 for Cycle 2), the Facility Permit holder may retroactively report concentrations that fell below 10 percent of the full scale span range at the 10 percent span range value, in lieu of using the Missing Data Procedures specified in Chapter 2, Subdivision E.

f. The Facility Permit holder electing to use (B)(8)(d)(ii) to measure and report NO_x concentrations that fall below 10 percent of the lowest vendor guaranteed full scale span range for that CEMS, shall meet the following:

i. Submit an application, with the appropriate fees, supporting documentation, and if necessary test protocols to the Executive Officer or designee in order to amend their CEMS Plan to include the selected criteria. The application shall be approved by the Executive Officer or designee prior to using (B)(8)(d)(ii).

ii. (B)(8)(d)(ii) may only be chosen after initial tests as prescribed in Attachment G are completed and demonstrate that the CEMS is capable of measuring NO_x concentrations at below 10 percent of the full scale span range.

iii. In the event any of the specified reporting and testing requirements for (B)(8)(d)(ii) as prescribed in Attachment G are not met, the Facility Permit holder shall no longer use (B)(8)(d)(ii) to measure NO_x concentrations below 10 percent of the lowest vendor guaranteed full scale span range for that CEMS until compliance with (B)(8)(d)(ii) is demonstrated. Missing Data Procedures described in Chapter 2, Subdivision E shall apply retroactively from the date in which the Facility Permit holder last demonstrated compliance with (B)(8)(d)(ii), unless the Facility Permit holder can demonstrate compliance with Attachment C (B)(2), then the Facility Permit holder may report concentrations retroactively at the 10 percent lowest vendor guaranteed span range value and may continue to report at the 10 percent lowest vendor guaranteed span range value until compliance is demonstrated with (B)(8)(d)(ii).

iv. In the event that the NO_x concentrations are at levels such that the Facility Permit holder cannot complete the low level spike recovery test or alternative reference method test for low level concentrations pursuant to Attachment G, then the Facility Permit holder may elect to report all monitored concentrations that fall below 10 percent of the lowest vendor guaranteed full scale span range at the 10 percent lowest vendor guaranteed full scale span range value in lieu of using Missing Data Procedures..

v. Upon approval of the CEMS application to use (B)(8)(d)(ii), the Facility Permit holder may retroactively report concentrations at the 10 percent lowest vendor guaranteed span range value in lieu of using the Missing Data Procedures specified Chapter 2, Subdivision E, from the beginning of the compliance year for which the application was submitted up until the application approval date.

g. Up until July 1, 1996, Facility Permit holders whose CEMS have been provisionally or finally certified prior to September 8, 1995, and have used Missing Data Procedures as prescribed in Chapter 2, Subdivision E to report mass emissions that have been measured by the CEMS in the 10 percent to less than 20 percent of full scale span range, may report the actual concentrations measured in this range as valid data retroactively from the beginning of the current compliance year.

9. Calibration Drift Requirements

The CEMS design shall allow determination of calibration drift (both negative and positive) at zero-level (0 to 20 percent of full scale) and high-level (80 to 100 percent of full scale) values. Alternative low-level and high-level span values may be allowed with the prior written approval of the Executive Officer.

10. Relative Accuracy Requirements for Stack Gas Volumetric Flow Measurement Systems

The stack gas volumetric flow measurement system shall meet a relative accuracy requirement of being less than or equal to 15 percent of the mean value of the reference method test data in units of standard cubic feet per hour (scfh). Relative accuracy is calculated by the equations in Section 8 of 40 CFR Part 60, Appendix B, Performance Specification 2. Alternatively, for cases where the mean stack gas velocity obtained by reference method test is less than 15 feet per second, the flow relative accuracy requirement may be met if equation 9a is satisfied.

$$|d| + |cc| \leq 2 \text{ feet per second} \times A \times cf \qquad \text{(Eq. 9a)}$$

Where

d = average of differences between stack gas volumetric flow measurement system reading and the corresponding reference method test data in units of standard cubic feet per hour.

cc = confidence coefficient as determined by the equations in Section 8 of 40 CFR Part 60, Appendix B, Performance Specification 2.

A = Stack cross sectional area in the plane of measurement.

cf = conversion factor to standard cubic feet per hour.

The volumetric flow measurement system shall also meet the specifications in Appendix B of these protocols. Prior to conducting a certification or re-certification test, the Facility Permit holder shall perform a flow profile study to determine the acceptability of the potential flow monitor location and to determine the number and location of flow sampling points required to obtain a representative flow value. The results of such study shall be part of the certification test report.

There shall be a minimum of nine sets of tests conducted. All data collected shall be submitted to the Executive Officer and shall be used to determine relative accuracy except data may be rejected per the technical guidance or for unusual problems and/or occurrences during testing (e.g., process upsets, CEMS malfunction, testing failure) if the number of tests exceeds nine sets. Any exclusion of data must be substantiated with appropriate documentation and is subject to approval by the Executive Officer.

In situations where the stack gas velocity is low (less than 10 ft./sec.) and the above relative accuracy procedure provides results that have a low level of accuracy and precision, the relative accuracy of the fuel flow meter may be determined according to one of the following alternatives:

a. Calibrate the facility CEMS fuel flow meter in accordance with the procedures outlined in 40 CFR Part 75, Appendix D, either in-line or off-line.

b. Calibrate a test fuel flow meter in accordance with the procedures outlined in 40 CFR Part 75, Appendix D. Use the calibrated test fuel meter to calibrate the facility CEMS fuel flow meter to the same level of accuracy and precision as in 40 CFR Part 75, Appendix D.

c. Calibrate a test fuel flow meter according to the procedure outlined in (B)(10)(b) and install this meter in line with the facility CEMS fuel flow meter and use 40 CFR Part 60, Method 19 (F-factor approach) to determine relative accuracy to the same level of accuracy as in (B)(10).

Other alternative techniques (e.g., tracer gas approach, electronic micro-manometer) may be used to determine relative accuracy of fuel flow meters where low stack volumetric flow rates exist, if these techniques are approved in writing by the District.

11. Relative Accuracy Requirements for Mass Emission Rate Measurement

The mass emission rate measurement shall meet a relative accuracy requirement of being less than or equal to 20 percent of the mean value of the reference method test data in units of lb/hr. Relative accuracy is calculated by the equations in Section 8 of 40 CFR, Part 60, Appendix B, Performance Specification 2. The emission rate measurement shall also meet the specifications in Attachment-B of this document. Alternatively, for cases where the mean NOx concentration obtained by reference test method is less than or equal to 5.0 ppm, or the mean stack gas velocity obtained by reference test method is less than 15 feet per second, the mass emission rate measurement relative accuracy requirement may be met if equation 9b is satisfied.

$$|d| + |cc| <= (c \times s \times A) \times cf \qquad \text{(Eq. 9b)}$$

Where

d = average of differences between mass emission rate determined by the CEMS and the corresponding reference method test data in units of pounds per hour.

cc = confidence coefficient as determined by the equations in Section 8 of 40 CFR Part 60, Appendix B, Performance Specification 2.

A = Stack cross sectional area in the plane of measurement.

c = 1.0 ppm or mean concentration obtained by reference test method, whichever is greater.

s = 2 feet per second or mean stack gas velocity obtained by reference test method, whichever is greater.
cf = conversion factor to pounds per hour.

There shall be a minimum of nine sets of tests conducted. All data collected shall be submitted to the Executive Officer and shall be used to determine relative accuracy except data may be rejected per the technical guidance or for unusual problems and/or occurrences during testing (e.g., process upsets, CEMS malfunction, testing failure) if the number of tests exceeds nine sets. Any exclusion of data must be substantiated with appropriate documentation and is subject to approval by the Executive Officer.

12. Relative Accuracy Requirements for Analyzers

The nitrogen oxides gas analyzers shall meet a relative accuracy requirement of being less than or equal to 20 percent of the mean value of the reference method test data in units of ppmv for nitrogen oxides. Relative accuracy is calculated by the equations in Section 8 of 40 CFR, Part 60, Appendix B, Performance Specification 2. Alternatively, for cases where the mean value of the reference method test data is less than 5 ppmv, the NOx concentration relative accuracy requirement may be met if equation 9c is satisfied.

$$|d| + |cc| <= 1.0 \text{ ppmv} \qquad \text{(Eq. 9c)}$$

Where:
d = average of differences between the NOx concentration measurement system reading and the corresponding reference method test data in units of ppmv.
cc = confidence coefficient as determined by the equations in Section 8 of 40 CFR Part 60, Appendix B, Performance Specification 2.

The oxygen and carbon dioxide gas analyzers shall meet a relative accuracy requirement of being less than or equal to 20 percent of the mean value of the reference method test data in units of volume percent. Relative accuracy is calculated by the equations in Section 8 of 40 CFR, Part 60, Appendix B, Performance Specification 2. Alternatively, for cases where the mean value of the reference method test data for oxygen or carbon dioxide concentration is less than 5.0 volume percent, the relative accuracy requirement for oxygen or carbon dioxide concentration may be met if equation 9d is satisfied.

$$|d| + |cc| <= 1.0 \text{ volume percent} \qquad \text{(Eq. 9d)}$$

Where:

d = average of differences between the oxygen or carbon dioxide concentration measurement system reading and the corresponding reference method test data.

cc = confidence coefficient as determined by the equations in Section 8 of 40 CFR Part 60, Appendix B, Performance Specification 2.

Units using monitors with more than one span range must perform the calibration error test on all span ranges. This portion of the CEMS shall also meet the specifications in Attachment B (BIAS TEST) of these protocols.

There shall be a minimum of nine sets of tests conducted. All data collected shall be submitted to the Executive Officer and shall be used to determine relative accuracy except data may be rejected per the technical guidance or for unusual problems and/or occurrences during testing (e.g., process upsets, CEMS malfunction, testing failure) if the number of tests exceeds nine sets. Any exclusion of data must be substantiated with appropriate documentation and is subject to approval by the Executive Officer.

13. Certification

a. Provisional Approval

The Facility Permit holder of a major source shall submit, certification test results and supporting documents to the District for each CEMS within the applicable time period required by Rule 2012 to install, operate, and maintain a CEMS. The Facility Permit holder shall certify that the results show that the CEMS has met all the requirements of the protocol if its submission is after August 31, 1994. Upon receipt of the test results and the certification that the CEMS is in compliance, the District will issue a Provisional Approval. The effective date of Provisional Approval shall be the last date of source testing if the test results are submitted within 60 days from the last date of source testing. However, if the test results are submitted more than 60 days after the last date of source testing, the effective date of Provisional Approval shall be the date of submittal of the testing results. After the Provisional Approval, the Facility Permit holder shall comply with the requirements under Attachment C - Quality Assurance and Quality Control Procedures.

b. Final Certification

After the Provisional Approval, all the data measured and recorded by the CEMS will be considered valid quality assured data provided that the Executive Officer does not issue a notice of disapproval of final certification. Final certification of the CEMS will be granted if the certification test results show that the CEMS has met all the requirements of the protocol, including Subdivision B, Paragraphs 10, 11, and 12 of this Chapter.

In the case where the test results show that the CEMS does not meet all the requirements of the rule, the Executive Officer will disapprove the final certification. If this occurs, the previously considered valid data from the date of Provisional Approval shall be replaced by data as specified in subdivision (E) - Missing Data Procedures. This procedure shall be used until the time that new certification test results are submitted, and the CEMS has received final approval by the District. After the Provisional Approval, the Facility Permit holder shall comply with the requirements under Attachment C - Quality Assurance and Quality Control Procedures. Data collected by the CEMS shall not be valid unless the CEMS is demonstrated to meet the requirements under Attachment C.

c. Re-certification

The Facility Permit holder shall conduct tests to re-certify a certified CEMS whenever the CEMS is modified in accordance with paragraph (B)(16).

14. Sampling Location Requirements

Each affected piece of equipment shall have sampling locations which meet the "Guidelines for Construction of Sampling and Testing Facilities" in the District Source Test Manual. If an alternate location (not conforming to the criteria of eight duct diameters downstream and two diameters upstream from a flow disturbance) is used, the absence of flow disturbance shall be demonstrated by using the District method in the Source Test Manual, Chapter X, Section 1.4, or 40 CFR, Part 60, Appendix A, Method 1. Section 2.5 and the absence of stratification shall be demonstrated using District method in the Source Test Manual, Chapter X, Section 13.

15. Sampling Line Requirement

The CEMS sample line from the CEMS probe to the sample conditioning system shall be heated to maintain the sample temperature above the dew point of the sample. This requirement does not apply to dilution probe systems where no sample condensation occurs.

16. Recertification Requirements

The District will reevaluate the monitoring systems at any affected piece of equipment where changes to the basic process equipment or air pollution control equipment occur, to determine the proper full span range of the monitors. Any monitor system requiring change to its full span range in order to meet the criteria in Chapter 2, Subdivision B shall be recertified according to all the specifications in Chapter 2, Subdivision B, Paragraphs 8, 10, 11, and 12, as applicable, including the relative accuracy tests, the calibration drift tests, and the calibration error tests. A new CEMS application shall be submitted for each CEMS which is reevaluated.

The recertification for any reevaluated CEMS, including existing, modified, or new CEMS, monitoring an existing or modified major source that was previously permitted under RECLAIM, shall be completed within 90 days of the start-up of the newly changed or modified equipment monitored by such CEMS. The Facility Permit holder shall calculate and report NOx emission data for the period prior to the CEMS recertification by means of the automated data acquisition and handling system according to the following procedures:

a. For any CEMS which is recertified within 90 days of start-up of the newly modified equipment, the emission data recorded by the CEMS prior to the recertification would be considered valid and shall be used for calculating and reporting NO_X emissions for the equipment it serves.

b. For any CEMS which is not recertified within 90 days of start-up of the newly modified equipment, the 90th percentile emission data (lbs per day) for the previous 90 unit operating days recorded by the CEMS prior to the recertification shall be used for calculating and reporting NO_X emissions for the equipment it serves.

17. Quality Assurance Procedures for Analyzers

The quality assurance and quality control requirements for analyzers, flow monitors, and NO_X emission rate systems are given in Attachment C (QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES) of these protocols. The quality assurance plans required by Attachment C of these protocols shall be submitted along with the CEMS certification application to the District for the approval of the Executive Officer . Source test and monitoring equipment inspection reports required by the Protocols shall be kept on-site for at least three years. The reference method tests are those methods in Chapter 8 - Reference Methods of these protocols. Any CEMS which is deemed out-of-control by Attachment C of these protocols shall be corrected, retested by the appropriate audit procedure, and restored to in-control condition within 24 hours after being deemed out-of-control. If the CEMS is not in-control at the end of the 24-hour period, the CEMS data shall be gathered using the methods in Chapter 2, Subdivision B, Paragraph 6 and Chapter 2, Subdivision B, Paragraph 7 of these requirements or using the Missing Data Procedures in Chapter 2 Subdivision E. All data which is gathered in order to comply with Attachment C of these protocols shall be maintained for three years and be made available to the Executive Officer upon request. Any such data which is invalidated shall be identified and reasons provided for any data invalidation. The nitrogen oxides and oxygen monitors shall also meet the specifications in Attachment B (BIAS TEST) of these protocols.

18. Quality Assurance for Fuel Flow Meters

Fuel flow measuring devices used for obtaining stack flow in conjunction with F-factors shall be tested as installed for relative accuracy using reference methods to determine stack flow.

If the flow device manufacturer has a method or device that permits the fuel flow measuring device to be tested as installed for relative accuracy, the Facility Permit holder shall request approval from the Executive Officer. Approval will be granted in cases where the Facility Permit holder can demonstrate to the satisfaction of the Executive Officer that no suitable testing location exists in the exhaust stacks or ducts and that it would be an inordinate cost burden to modify the exhaust stack configuration to provide a suitable testing location. The method or device used for relative accuracy testing shall be traceable to NIST standards. This method shall be used only if natural gas, fuel oil, or other fuels can be shown, by the Facility Permit holder to have stable F-factors and gross heating values, or if the Facility Permit holder measures the F-factor and gross heating value of the fuel. A stable F-Factor is defined as not varying by more than +/-2.5% from the constant value used for F-Factor. For the fuels listed in 40 CFR 60, Appendix A, Method 19, Table 19-1, the F-Factors are assumed to be stable at the value cited in Table 19-1. Any F-Factor cited in Regulation XX shall supersede the f-Factor in Table 19-1. For fuels not listed in the citations above, but which the Facility Permit holder can demonstrate that the source-specific F-Factor meets the same stability criteria, periodic reporting of F-Factor may be accepted and the adequacy of the frequency of analyses shall be demonstrated by the facility such that the probability that any given analysis will differ from the previous analysis by more than 5% (relative to the previous analysis) is less than 5%. Analysis records shall be maintained, including all charts and laboratory notes.

19. Calibration Gas Traceability

All calibration gases used during certification tests and quality assurance and quality control activities shall be NIST/EPA approved standard reference materials (SRM), certified reference materials (CRM), or shall be certified according to ”EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,” September 1997, EPA 600/R-97/121 or any subsequent version published by EPA.

20. Relative Accuracy Test Audits Report Submittal

A test report shall be submitted to the District for each semi-annual or annual assessment test of a CEMS as required under Paragraph (B)(2) of Attachment C - Quality Assurance and Quality Control Procedures. Such report shall be submitted on or before the end of the quarter following the date of a required test.

21. Concentration Stratification

a. The owner or operator shall demonstrate at the time of certification and re-certification the absence of stratification for locating a facility CEMS gas sampling probe through testing performed according to the method in Chapter X, “Non-Standard Methods and Techniques”, of the District Source Testing Manual. The number of tests shall be determined as follows:

   i. A minimum of one test shall be conducted if the owner or operator demonstrates to the satisfaction of the Executive Officer that the equipment operates within a 20 percent load range for at least 80 percent of the time;

   ii. A minimum of two tests shall be conducted if the equipment operates between 20 and 50 percent load range for at least 80 percent of the time; or,

   iii. A minimum of three tests shall be conducted if the equipment operates outside of the criteria in clauses (i) and (ii) above.

   The absence of stratification is considered verified if the difference between the highest measured concentration (time normalized) and the lowest measured concentration (time normalized) divided by the average measured concentration (time normalized), when expressed as a percentage, is less than or equal to 10 percent. Upon verification of the absence of stratification, the owner or operator may position the CEMS sampling probe at any point within the stack with the exception of those points that are adjacent to the stack wall. The CEMS sampling probe should be located in the stack at least one-third of the stack diameter. The RM for RATA may be conducted at a single point within the stack that is not adjacent to the stack wall and does not interfere with the sampling and the operation of the facility CEMS.

b. If testing demonstrates the presence of stratification, the owner or operator shall elect one of the following alternatives:

i. The owner or operator may use a single point sampling probe, if the stratification is greater than 10 percent but the difference between the highest measured concentration (time normalized) and the lowest measured concentration (time normalized) is less than or equal to 1.0 ppmv:

I. Then the CEMS sampling probe may be located at any point within the stack except any points that are adjacent to the stack wall or adjacent to either the highest measured concentration (time normalized) or the lowest measured concentration (time normalized), or

II. If it is not possible to avoid using a point adjacent to either the highest measured concentration (time normalized) or the lowest measured concentration (time normalized), then locate the CEMS sampling probe such that the placement minimizes the difference between the concentration; at the proposed probe location and the concentration at the point of highest measured concentration (time normalized) or the lowest measured concentration (time normalized).

ii. The owner or operator may use a single point sampling probe, if there exists a representative CEMS probe location such that all of the following criteria are met:

I. Each traverse point concentrations is within 10.0% of the average of all traverse point concentrations (time normalized), or the difference between each traverse concentration and the average of all traverse point concentrations is less than or equal to 1.0 ppm, and

II. at least one traverse point concentration, not located next to the stack or duct wall, is within 10.0% of each adjacent traverse point concentration, or the difference between each traverse point concentration and the average of all traverse point concentrations is less than or equal to 1.0 ppm, whichever is greater, and,

III. if more than one traverse point meets the criteria listed in subclause (ii)(II), the CEMS probe shall be located at (or as near as practical) the traverse point with minimum adjacent traverse point concentration fluctuations as determined in section (ii)(II), above.

iii. The owner or operator may use a multipoint sampling probe and determine a representative multiple point sampling configuration as approved by the Executive Officer.

iv. The owner or operator may elect to modify the stack and/or CEMS sampling probe location and retest for the absence of stratification.

C. REPORTING PROCEDURES

1. Interim Reporting Procedures

a. From January 1, 1994 until December 31, 1994 (Cycle 1 facilities) and July 1, 1994 until June 30, 1995 (Cycle 2 facilities), the Facility Permit holder shall be allowed to use an interim procedure for data reporting and storage. The Facility Permit holder shall submit as part of the Facility Permit application, the methodology for interim data reporting and storage. The Facility Permit application shall be subject to the approval of the Executive Officer and shall, at a minimum, meet the requirements of Chapter 2, Subdivision C, Paragraph 1 Subparagraphs b, c, and d

b. All the data required in Chapter 2, Subdivision C, Paragraph 1, Subparagraphs c and d shall be made available to the Executive Officer.

c. For each piece of equipment the following information shall be stored on site and be made available to the Executive Officer upon request:

i. Calendar dates covered in the reporting period;

ii. Each monthly emissions (lb NO_X/month) and each hourly emissions (lb NO_X/hour);

iii. Identification of the operating hours for which a sufficient number of valid data points has not been taken, reasons for not taking sufficient data, and a description of corrective action taken;

iv. Identification of F_d factor for each type of fuel used for calculations and the type of fuel burned;

d. The following information for the entire facility shall be on a monthly basis in a format approved by the Executive Officer:

i. Calendar dates covered in the reporting period;

ii. The sum of the daily emissions (lb NO_X/day) from all NO_X RECLAIM sources.

e. All data required by Chapter 2, Subdivision C, Paragraph 1, Subparagraphs c and d shall be recorded and/or transmitted to the District in a format specified by the Executive Officer.

2. Final Reporting Procedures

a. On and after January 1, 1995 (Cycle 1 facilities) and July 1, 1995 (Cycle 2 facilities), the RTU installed at each location shall be used to electronically report total daily mass emissions of NO_x and daily status codes to the District Central NO_x Station.

b. On and after January 1, 1995 (Cycle 1 facilities) and July 1, 1995 (Cycle 2 facilities), the Facility Permit holder shall submit to the Executive Officer a Monthly Emissions Report in the manner and form specified by the Executive Officer within 15 days following the end of each calendar month.

c. On and after January 1, 1995 (Cycle 1 facilities) and July 1, 1995 (Cycle 2 facilities), all or part of the interim data storage systems shall remain as continuous backup systems.

d. An alternate backup data storage system may be implemented, upon request.

D. ALTERNATIVE PROCEDURES FOR EMISSION STACK FLOW RATE DETERMINATION

1. Multiple Sources Venting to a Common Stack

In the event that more than one source vents to a common stack, the alternative reference method for determining individual source flow rates shall use the F-factors in EPA Method 19 and the following equation:

$$c_i = [20.9/(20.9 - b_i)] \times \sum_{j=1}^{r} (F_{dij} \times d_{ij} \times V_{ij}) \qquad \text{(Eq. 10)}$$

where:

c_i = The stack gas volumetric flow rate for the individual source(scfh),

b_i = The stack gas concentration of oxygen (percent),

F_{dij} = The oxygen-based dry F factor for each type of fuel, the ratio of the dry gas volume of the products of combustion to the heat content of the fuel (scf/mm Btu)

d_{ij} = The fuel flow rate for each type of fuel for individual source measured every 15-minute period

V_{ij} = The higher heating value of the fuel for each type of fuel

The product d_{ij} x V_{ij} shall have units of millions of Btu per hour (mmBtu/hr)

The measurement of wet concentration and wet F factor shall be allowed provided that wet concentration of NO_x is measured.

Example Calculation:

b_i = 4.2 percent O_2

F_{dij} = 8710 dscf/10^6 Btu

d_{ij} = 3000 dscfh

V_{ij} = 1050 Btu/scf

c_i = [20.9/(20.9 - 4.2)] x [(8710/10^6)(3000)(1050)

c_i = 34,337 dscfh

This method may be used for applicable sources before and after the interim period mentioned in Chapter 2, Subdivision C, Paragraph 1. The orifice plates used in each affected piece of equipment vented to a common stack shall meet the requirements in Chapter 2, Subdivision D, Paragraph 2.

2. Quality Assurance for Orifice Plate Measurements

Each orifice plate used to measure the fuel gas flow rate shall be checked once every 12 months using Reference Methods. If the orifice plate cannot be checked using Reference Methods, it may be checked using other methods that can show traceability to NIST standards. If the orifice plate cannot be checked by Reference Methods or other methods that can show traceability to NIST standards, the orifice plate shall be removed from the gas supply line for an inspection once every 12 months, and the following inspection procedure shall be followed:

a. Each orifice plate shall be visually inspected for any nicks, dents, corrosion, erosion, or any other signs of damage according to the orifice plate manufacturer's specifications.

b. The diameter of each orifice shall be measured using the method recommended by the orifice plate manufacturer.

c. The flatness of the orifice plate shall be checked according to the orifice manufacturer's instructions. The departure from flatness of an orifice plate shall not exceed 0.010 inches per inch of dam height (D-d/2) along any diameter. Here, D is the inside pipe diameter, and d is the orifice diameter at its narrowest constriction.

d. The pressure gauge or other device measuring pressure drop across the orifice shall be calibrated against a manometer, and shall be replaced if it deviates by more than ±2 percent across the range.

e. The surface roughness shall be measured using the method recommended by the orifice plate manufacturer. The surface roughness of an orifice plate shall not exceed 50 microinches.

f. The upstream edge of the measuring orifice shall be square and sharp so that it shall not show a beam of light when checked with an orifice gauge.

g. In centering orifice plates, the orifice shall be concentric with the inside of the meter tube or fitting. The concentricity shall be maintained within 3 percent of the inside diameter of the tube or fitting along all diameters.

h. Any other calibration tests specified by the orifice manufacturer shall be conducted at this time.

If an orifice plate fails to meet any of the manufacturer's specifications, it shall be replaced within two weeks of the inspection.

E. MISSING DATA PROCEDURES

The following Missing Data Procedures shall be used to determine substitute data whenever a valid hour of NO_x emission data has not been obtained or recorded.

1. Procedures for Missing NO_X Concentration Data

For each equipment, whenever a valid hour of NO_X pollution concentration data has not been obtained or recorded, the Facility Permit holder shall provide substitute data using the procedures below. Alternatively, a facility may provide NO_X pollution concentration missing data using the procedure in 40 CFR Part 75 Subpart D for SO_2 emissions (in lb/hr) if the relative accuracy of the pollutant analyzer and flow measurement system during the last CEMS certification test and/or RATA are both less than 10 percent.

a. The Facility Permit holder shall calculate on a daily basis the percent data availability from the NO_X pollutant concentration monitoring analyzer according to the following procedures:

i. Calculate on a daily basis a rolling percentage of the operating hours of each equipment that each concentration monitoring system was available for the period from the date the NOx pollutant concentration monitoring analyzer was provisionally certified or 365 days prior to the current date (not counting the current day), whichever date is later, to the day previous to the current date.

ii. Record on a daily basis the percent annual concentration monitor availability using the following equation:

$$W = Y/Z \times 100\% \qquad \text{(Eq.13)}$$

where:

W = the percent annual monitor availability

Y = the total operating hours for which the monitor provided quality-assured data during the period from the date the NOx pollutant concentration monitoring analyzer was provisionally certified or 365 days prior to the current date (not counting the current day), whichever date is later, to the day previous to the current date.

Z = the total operating hours of the affected piece of equipment during the period from the date the NOx pollutant concentration monitoring analyzer was provisionally certified or 365 days prior to the current date (not counting the current day), whichever date is later, to the day previous to the current date.

Example Calculation:

$$Y = 1{,}680 \text{ hrs}$$

$$Z = 2{,}160 \text{ hrs}$$

$$W = Y/Z \times 100\%$$

$$W = (1{,}680/2{,}160) \times 100\%$$

$$W = 77.78 \text{ percent}$$

b. Whenever the percent annual monitor availability is 95 percent or more, the Facility Permit holder shall calculate substitute data for each hour according to the following procedures.

i. For a missing data period less than or equal to 24 hours, substitute data shall be calculated using the 1N Procedure in Attachment A. If insufficient data is available to perform this calculation, substitute data shall be calculated pursuant to clause E(1)(b)(ii).

ii. For a missing data period greater than 24 hours, substitute data shall be calculated using the maximum hourly concentration recorded by the concentration monitor for the previous 30 days. If no emissions occurred during the previous 30 days, substitute data shall be calculated pursuant to clause E(1)(c)(i)(III).

c. i. Whenever the percent annual monitor availability is 90-percent or more but less than 95-percent, the Facility Permit holder shall calculate substitute data for each hour according to the following procedures.

I. For a missing data period of less than or equal to 3 hours, substitute data shall be calculated using the average of the recorded concentration for the hour immediately before the missing data period and the hour immediately after the missing data period. If no emissions occurred during the hour immediately before the missing data period or the hour immediately after the missing data period, substitute data shall be calculated pursuant to clause E(1)(c)(i)(II).

II. For a missing data period of more than 3 hours but less than or equal to 24 hours, substitute data shall be calculated using the maximum hourly concentration recorded by the concentration monitor for the previous 30 days. If no emissions occurred during the previous 30 days, substitute data shall be calculated pursuant to clause E(1)(c)(i)(III).

III. For a missing data period of greater than 24 hours, substitute data shall be calculated using the maximum hourly concentration recorded by the concentration monitor for the previous 365 days. If no emissions occurred during the previous 365 days, substitute data shall be calculated pursuant to clause E(1)(c)(ii).

ii. Whenever the percent annual monitor availability is less than 90 percent, substitute data shall be calculated using the highest hourly concentration recorded during the service of the monitoring system. For the purpose of this subparagraph, service of the monitoring system shall start from the initial certification date of the analyzer or the date when a decrease in the valid range of the monitoring system is approved by the Executive Officer.

d. For missing data periods where there is no prior CEMS data available or the highest CEMS data is zero:

i. for less than or equal to 24 hours, the mass emissions shall be calculated using totalized fuel usage and the starting emission factor specified in Table 1 of Rule 2002 or any alternative emission factor used in the determination of initial allocations; or

ii. for less than or equal to 24 hours and where fuel usage is not available, the mass emissions shall be calculated using the equipment maximum rated capacity, 100 percent equipment uptime, and the starting emission factor specified in Table 1 of Rule 2002; or

iii. for greater than 24 hours, the mass emissions shall be calculated using the equipment maximum rated capacity, 100 percent equipment uptime, and the uncontrolled emission factors specified in Table 3-D. An uncontrolled emission factor is an emission factor representative of the emissions prior to any emission control equipment from the source. For equipment not specified in Table 3D, an uncontrolled emission factor can be determined based on the starting emission factor used in the determination of initial allocations discounted by any control efficiency, or based on source test data. In determining a control efficiency, the facility permit holder may use source test data, or the default control efficiency as listed in Table 3-E.

iv. Retroactively from January 1, 1995 and ending June 30, 1995, for Cycle 1 Facility Permit holders with major NO_x sources that do not have an approved RECLAIM certified CEMS, may calculate NO_x daily mass emissions in lieu of the procedures specified in the above clauses E(1)(d)(i), E(1)(d)(ii), and E(1)(d)(iii), using (1) the emission factor specified in Table 1 of Rule 2002 or any alternative factor used in the determination of initial allocations or specified in the facility permit and (2) the totalized fuel usage or process throughput.

v. Facility Permit holders with NO_x major sources which demonstrate to the satisfaction of the Executive Officer or designee that standard equipment is not available for measuring exhaust emissions for the purpose of RECLAIM CEMS certification may submit an application by December 31, 1995 to use an alternative exhaust gas and/or pollutant concentration measuring equipment. Such equipment must employ commercially available technology, and must be demonstrated to meet all the requirements of CEMS certification. Upon approval of the application, the Facility Permit holder may calculate NO_x daily mass emissions in lieu of the procedures specified in clauses E(1)(d)(i), E(1)(d)(ii), and E(1)(d)(iii), using the alternate method of (1) the emission factor specified in the facility permit and (2) the totalized fuel usage or process throughput. Such calculation of NO_x mass emissions may be done retroactively from July 1, 1995 and ending December 31, 1997 or until the CEMS is finally certified, whichever is earlier. The alternate method of calculating mass emissions shall be applied after the proposed equipment has been approved by the Executive Officer. If the CEMS is not certified by December 31, 1997, then NO_x daily mass emissions shall be calculated by the procedures specified in clauses E(1)(d)(i), E(1)(d)(ii), and E(1)(d)(iii) retroactive to July 1, 1995.

vi. If the Facility Permit holder demonstrates that standard equipment is not available but alternative equipment is commercially available as set forth in (E)(1)(d)(v) and also demonstrates to the satisfaction of the Executive Officer or designee that their CEMS cannot be certified because (1) there is an inordinate cost burden for flow monitoring as specified under (B)(11) and (2) that the Reference Methods, as specified in Rule 2012(j)(1) and Appendix A, cannot be applied because no suitable testing location exists in the exhaust stacks or ducts, then the Facility Permit holder may submit an alternative CEMS plan for certification by December 31, 1995. This plan must demonstrate that the proposed monitoring system complies with all other requirements of CEMS certification and is the most technically feasible in measurement accuracy. Until the alternative CEMS is certified or up until December 31, 1997, whichever is earlier, and retroactive to July 1, 1995, the Facility Permit holder may calculate NO_x daily mass emissions in lieu of the procedures specified in clauses E(1)(d)(i), E(1)(d)(ii), and E(1)(d)(iii), using the alternate method of (1) the emission factor specified in the facility permit and (2) the totalized fuel usage or process throughput. If the CEMS is not certified by December 31, 1997, then NO_x daily mass emissions shall be calculated by the procedures specified in clauses E(1)(d)(i), E(1)(d)(ii), and E(1)(d)(iii).

2. Procedures for Missing Stack Exhaust Gas Flow Rate Data

For each equipment, whenever a valid hour of stack exhaust gas flow rate data has not been obtained or recorded, the Facility Permit holder shall provide substitute data using the procedures below. Alternatively, a facility may provide stack exhaust gas flow rate data using the procedure in 40 CFR Part 75 Subpart D if the relative accuracy of the pollutant analyzer, flow measurement system, and emission rate measurement during the last CEMS certification test and/or RATA are all less than 10 percent.

a. The Facility Permit holder shall calculate on a daily basis the percent data availability from the flow monitoring system according to the following procedures:

i. Calculate on a daily basis a rolling percentage of the operating hours of each equipment that each flow monitoring system was available for the period from the date the NOx pollutant concentration monitoring analyzer was provisionally certified or 365 days prior to the current date (not counting the current day), whichever date is later, to the day previous to the current date.

ii. Record on a daily basis the percent annual flow monitor availability using the following equation:

$$W = Y/Z \times 100\% \quad \text{(Eq. 12)}$$

where:

W = the percent annual flow monitor availability

Y = the total operating hours for which the monitor provided quality-assured data during the period from the date the NOx pollutant concentration monitoring analyzer was provisionally certified or 365 days prior to the current date (not counting the current day), whichever date is later, to the day previous to the current date.

Z = the total operating hours of the affected piece of equipment during the period from the date the NOx pollutant concentration monitoring analyzer was provisionally certified or 365 days prior to the current date (not counting the current day), whichever date is later, to the day previous to the current date.

Example Calculation:

Y = 1,680 hrs

Z = 2,160 hrs

W = Y/Z x 100%

W = (1,680/2,160) x 100%

W = 77.78 percent

b. Whenever the percent annual flow monitor availability is 95 percent or more, the Facility Permit holder shall calculate substitute data for each hour according to the following procedures.

i. For a missing data period less than or equal to 24 hours, substitute data shall be calculated using the 1N Procedure in Attachment-A. If insufficient data is available to perform this calculation, substitute data shall be calculated pursuant to clause E(2)(b)(ii).

ii. For a missing data period greater than 24 hours, substitute data shall be calculated using the maximum hourly flow recorded by the flow monitor for the previous 30 days. If no emissions occurred during the previous 30 days, substitute data shall be calculated pursuant to clause E(2)(c)(iii).

c. Whenever the percent annual flow monitor availability is 90-percent or more but less than 95-percent, the Facility Permit holder shall calculate substitute data for each hour according to the following procedures.

i. For a missing data period of less than or equal to 3 hours, substitute data shall be calculated using the average of the recorded flow rate for the hour immediately before the missing data period and the hour immediately after the missing data period. If no emissions occurred during the hour immediately before the missing data period or the hour immediately after the missing data period, substitute data shall be calculated pursuant to clause E(2)(c)(ii).

ii. For a missing data period of more than 3 hours but less than or equal to 24 hours, substitute data shall be calculated using the maximum hourly flow rate recorded by the flow monitor for the previous 30 days. If no emissions occurred during the previous 30 days, substitute data shall be calculated pursuant to clause E(2)(c)(iii).

iii. For a missing data period of greater than 24 hours, substitute data shall be calculated using the maximum hourly flow rate recorded by the flow monitor for the previous 365 days. If no emissions occurred during the previous 365 days, substitute data shall be calculated pursuant to subparagraph E(2)(d).

d. Whenever the percent annual flow monitor availability is less than 90 percent, substitute data shall be calculated using the highest hourly flow rate recorded during the service of the monitoring system. For the purpose of this subparagraph, service of the monitoring system shall start from the initial certification date of the analyzer or the date when a decrease in the valid range of the monitoring system is approved by the Executive Officer.

3. Procedures for Missing Stack Exhaust Gas Flow Rate Data and Missing NO_X Concentration Data

For each equipment, whenever a valid hour of both stack exhaust gas flow rate data and NO_X pollution concentration data have not been obtained or recorded, the Facility Permit holder shall provide substitute data using emissions data and the procedures below.

a. The Facility Permit holder shall calculate and record on a daily basis the percent annual emission availability. The percent annual emission availability shall be equal to the lesser of the percent annual concentration monitor availability as determined in subparagraph E(1)(a) or the percent annual flow monitor availability as determined in subparagraph E(2)(a).

b. Whenever the percent annual emission availability is 95 percent or more, the Facility Permit holder shall calculate substitute data for each hour according to the following procedures.

  i. For a missing data period less than or equal to 24 hours, substitute data shall be calculated using the 1N Procedure in Attachment-A. If insufficient data is available to perform this calculation, substitute data shall be calculated pursuant to clause E(3)(b)(ii).

  ii. For a missing data period greater than 24 hours, substitute data shall be calculated using the maximum hourly emissions for the previous 30 days. If no emissions occurred during the previous 30 days, substitute data shall be calculated pursuant to clause E(3)(c)(iii).

c. Whenever the percent annual emission availability is 90-percent or more but less than 95-percent, the Facility Permit holder shall calculate substitute data for each hour according to the following procedures.

  i. For a missing data period of less than or equal to 3 hours, substitute data shall be calculated using the average of the recorded emissions for the hour immediately before the missing data period and the hour immediately after the missing data period. If no emissions occurred during the hour immediately before the missing data period or the hour immediately after the missing data period, substitute data shall be calculated pursuant to clause E(3)(c)(ii).

  ii. For a missing data period of more than 3 hours but less than or equal to 24 hours, substitute data shall be calculated using the maximum hourly emissions recorded for the previous 30 days. If no emissions occurred during the previous 30 days, substitute data shall be calculated pursuant to clause E(3)(c)(iii).

iii. For a missing data period of greater than 24 hours, substitute data shall be calculated using the maximum hourly emissions for the previous 365 days. If no emissions occurred during the previous 365 days, substitute data shall be calculated pursuant to subparagraph E(3)(d).

d. Whenever the percent annual emission availability is less than 90 percent, substitute data shall be calculated using the highest hourly emissions recorded during the service of the monitoring system. For the purpose of this subparagraph, service of the monitoring system shall start from the initial certification date of the analyzer or the date when a decrease in the valid range of the monitoring system is approved by the Executive Officer.

F. TIME-SHARING

1. Time-sharing is where an analyzer and possibly the associated sample conditioning system is used on more than one source. Time-sharing is allowed for NO_X RECLAIM sources provided the CEMS can meet the following requirements in addition to the other requirements in this document for each source that is time-shared.

2. All sources shall have mutually compatible span range(s). The span range(s) shall be able to meet the criteria in Chapter 2, Subdivision B, Paragraph 8.

3. Each source shall have a data reading period greater than or equal to 3 times the longest response time of the system. For shared systems the response time is measured at the input or probe at each source. A demonstration of response time for each source shall be made during certification testing. Data is not to be collected following a switch of sampled sources until an amount of time equal to the response time has passed.

4. The CEMS shall be able to perform and record zero and span calibrations at each source.

G. EMISSIONS DURING STARTUP OR SHUTDOWN PERIODS

The Facility Permit holder of a major source with startup or shutdown periods during which the pollutant or diluent concentrations do not fall within 10 - 95 percent of the normal operation span range(s) shall apply the following methodology; otherwise, the Facility Permit holder shall comply with Chapter 2, Subdivision E, Paragraph 1 - Missing Data Procedures:

1. During equipment startup or shutdown the Facility Permit holder shall apply the unregulated emission factor specified in Table 3-D; or

2. If the emission factors in Table 3-D do not reflect the emission factors during startup and shutdown periods, the Facility Permit holder shall propose emission factors for the approval of the Executive Officer and shall submit source test data to substantiate the proposed emission factors. The hourly average emissions during startup and shutdown periods shall be calculated and reported according to:

$$E_{st} = D_{st} \times EF_{st} \qquad \text{(Eq.13)}$$

where:

E_{st} = The hourly mass emission of nitrogen oxides during startup period (lb/hr).

D_{st} The hourly average fuel flow rate for each type of fuel during startup period (mmscf/hr or mgal/hr).

EF_{st} The unregulated or Facility Permit holder-specified emission factor during startup period (lb/mmscf or lb/mgal).

$$E_{sh} = D_{sh} \times EF_{sh} \qquad \text{(Eq.14)}$$

where:

E_{sh} = The hourly mass emission of nitrogen oxides during shutdown period (lb/hr).

D_{sh} = The of hourly fuel flow rate for each type of fuel during shutdown period (mmscf/hr or mgal/hr).

EF_{sh} = The unregulated or Facility Permit holder-specified emission factor during shutdown period (lb/mmscf or lb/mgal).

TABLE 2-A

MEASURED VARIABLES FOR MAJOR NO_x SOURCES

EQUIPMENT TYPE : BOILERS

EQUIPMENT	MEASURED VARIABLES
Boilers	1. Stack NO_x concentration and exhaust flow rate; OR Stack NO_x, and O_2 concentrations, and fuel flow rate; 2. Status codes; 3. Steam production rate;
Boilers with low NO_x burners	All variables identified for boilers.
Boilers with staged combustion	All variables identified for boilers.
Boilers with FGR	All variables identified for boilers; AND 4. Flue gas recirculation rate.
Boilers with SCR	All variables identified for boilers; AND 4. Ammonia injection rate; 5. Temperature of the inlet gas stream to SCR;
Boilers with SNCR	All variables identified for boilers; AND 4. Ammonia (or urea) injection rate; 5. Temperature of the inlet gas stream to SNCR;
Boilers with NSCR	All variables identified for boilers; AND 4. Natural gas (or other HC) injection rate.

TABLE 2-A (CONTINUED)

MEASURED VARIABLES FOR MAJOR NO_X SOURCES

EQUIPMENT TYPE : FURNACES

EQUIPMENT	MEASURED VARIABLES
Furnaces	1. Stack NO_x concentration and exhaust flow rate; OR Stack NO_x, and O_2 concentrations, and fuel flow rate; 2. Status codes; 3. Production rate;
Furnaces with low NO_X burners	All variables identified for furnaces.
Furnaces with combustion modification	All variables identified for furnaces.
Furnaces with SCR	All variables identified for furnaces; AND 4. Ammonia injection rate; 5. Temperature of the inlet gas stream to SCR;
Furnaces with SNCR	All variables identified for furnaces; AND 4. Ammonia (or urea) injection rate; 5. Temperature of the inlet gas stream to SNCR;

TABLE 2-A (CONTINUED)

MEASURED VARIABLES FOR MAJOR NO_x SOURCES

EQUIPMENT TYPE : OVENS

EQUIPMENT	MEASURED VARIABLES
Ovens	1. Stack NO_x concentration and exhaust flow rate; OR Stack NO_x, and O_2 concentrations, and fuel flow rate; 2. Status codes; 3. Production rate;
Ovens with low NO_x burners	All variables identified for ovens.
Ovens with combustion modification	All variables identified for ovens.
Ovens with SCR	All variables identified for ovens; AND 4. Ammonia injection rate; 5. Temperature of the inlet gas stream to SCR;
Ovens with SNCR	All variables identified for ovens; AND 4. Ammonia (or urea) injection rate; 5. Temperature of the inlet gas stream to SNCR;

TABLE 2-A (CONTINUED)

MEASURED VARIABLES FOR MAJOR NO_x SOURCES

EQUIPMENT TYPE : DRYERS

EQUIPMENT	MEASURED VARIABLES
Dryers	1. Stack NO_x concentration and exhaust flow rate; OR Stack NO_x, and O_2 concentrations, and fuel flow rate; 2. Status codes; 3. Production rate;
Dryers with low NO_x burners	All variables identified for dryers.
Dryers with combustion modification	All variables identified for dryers.
Dryers with FGR	All variables identified for dryers; AND 4. Flue gas recirculation rate.
Dryers with SCR	All variables identified for dryers; AND 4. Ammonia injection rate; 5. Temperature of the inlet gas stream to SCR;
Dryers with SNCR	All variables identified for dryers; AND 4. Ammonia (or urea) injection rate; 5. Temperature of the inlet gas stream to SNCR;
Dryers with NSCR	All variables identified for dryers; AND 4. Natural gas (or other HC) injection rate.

TABLE 2-A (CONTINUED)

MEASURED VARIABLES FOR MAJOR NO_x SOURCES

EQUIPMENT TYPE : PROCESS HEATERS

EQUIPMENT	MEASURED VARIABLES
Process heaters	1. Stack NO_x concentration and exhaust flow rate; OR Stack NO_x, and O_2 concentrations, and fuel flow rate; 2. Status codes; 3. Production rate;
Process heaters with low NO_x burners	All variables identified for process heaters.
Process heaters with combustion modification	All variables identified for process heaters.
Process heaters with FGR	All variables identified for process heaters; AND 4. Flue gas recirculation rate.
Process heaters with SCR	All variables identified for process heaters; AND 4. Ammonia injection rate; 5. Temperature of the inlet gas stream to SCR;
Process heaters with SNCR	All variables identified for process heaters; AND 4. Ammonia (or urea) injection rate; 5. Temperature of the inlet gas stream to SNCR;
Process heaters with NSCR	All variables identified for process heaters; AND 4. Natural gas (or other HC) injection rate.
Process heaters with water (or steam) injection	All variables identified for process heaters; AND 4. Water (or steam) injection rate.

TABLE 2-A (CONTINUED)

MEASURED VARIABLES FOR MAJOR NO_x SOURCES

EQUIPMENT TYPE : INCINERATORS

EQUIPMENT	MEASURED VARIABLES
Incinerators	1. Stack NO_x concentration and exhaust flow rate; OR Stack NO_x, and O_2 concentrations, and fuel flow rate; 2. Status codes; 3. Production rate;
Incinerators with SCR	All variables identified for incinerators; AND 4. Ammonia injection rate; 5. Temperature of the inlet gas stream to SCR;
Incinerators with SNCR	All variables identified for incinerators; AND 4. Ammonia (or urea) injection rate; 5. Temperature of the inlet gas stream to SNCR;

Table 2-A (CONTINUED)

MEASURED VARIABLES FOR MAJOR NO_X SOURCES

EQUIPMENT TYPE : REFINERY TAIL GAS UNITS

Refinery tail gas units	1. Stack NO_x concentration and exhaust flow rate; OR; Stack NO_x, and O_2 concentrations, and fuel flow rate; 2. Status codes; 3. Production rate;

TABLE 2-A (CONTINUED)

MEASURED VARIABLES FOR MAJOR NO_x SOURCES

EQUIPMENT TYPE : TEST CELLS

EQUIPMENT	MEASURED VARIABLES
Test cells	1. Stack NO_x concentration and exhaust flow rate; OR Stack NO_x, and O_2 concentrations, and fuel flow rate; 2. Status codes; 3. Shaft horsepower output or other measure of system output;
Test cells with SCR	All variables identified for test cells; AND 4. Ammonia injection rate; 5. Temperature of the inlet gas stream to SCR;
Test cells with Packed Chemical Scrubber	All variables identified for test cells; AND 4. Chemical injection rate.

TABLE 2-A (CONTINUED)

MEASURED VARIABLES FOR MAJOR NO_x SOURCES

EQUIPMENT TYPE : INTERNAL COMBUSTION ENGINES

EQUIPMENT	MEASURED VARIABLES
Internal combustion engines	1. Stack NO_x concentration and exhaust flow rate; OR Stack NO_x, and O_2 concentrations, and fuel flow rate; 2. Status codes; 3. Throttle setting shaft horsepower output or other measure of system output;
Internal combustion engines with combustion modification	All variables identified for internal combustion engines.
Internal combustion engines with Injection Timing Retard 4 degree	All variables identified for internal combustion engines.
Internal combustion engines with turbocharger, aftercooler, intercooler.	All variables identified for internal combustion engines.
Internal combustion engines with SCR	All variables identified for internal combustion engines; AND 4. Ammonia injection rate; 5. Temperature of the inlet gas stream to SCR;
Internal combustion engines	All variables identified for internal combustion engines; with NSCR AND 4. Natural gas (or other HC) injection rate.

TABLE 2-A (CONTINUED)

MEASURED VARIABLES FOR MAJOR NO_x SOURCES

EQUIPMENT TYPE : GAS TURBINES

EQUIPMENT	MEASURED VARIABLES
Gas turbines	1. Stack NO_x concentration and exhaust flow rate; OR Stack NO_x, and O_2 concentrations, and fuel flow rate; 2. Status codes; 3. Shaft horsepower output or other measure of system output;
Gas turbines with Water or Steam Injection	All variables identified for gas turbines; AND 4. Water or steam injection rate;
Gas turbines with SCR and Steam Injection	All variables identified for gas turbines; AND 4. Ammonia injection rate; or 5. Steam injection rate 6. Temperature of the inlet gas stream to SCR;
Gas turbines with SCR and Water Injection	All variables identified for gas turbines; AND 4. Ammonia injection rate; or 5. Water injection rate 6. Temperature of the inlet gas stream to SNCR;

TABLE 2-A (CONTINUED)

MEASURED VARIABLES FOR MAJOR NO_x SOURCES

EQUIPMENT TYPE : KILNS AND CALCINERS

EQUIPMENT	MEASURED VARIABLES
Kilns and calciners	1. Stack NO_x concentration and exhaust flow rate; OR Stack NO_x, and O_2 concentrations, and fuel flow rate; 2. Status codes; 3. Production rate;
Kilns and calciners with low NO_x burners	All variables identified for kilns and calciners.
Kilns and calciners with combustion modifications	All variables identified for kilns and calciners.
Kilns and calciners with FGR	All variables identified for kilns and calciners; AND 4. Flue gas recirculation rate.
Kilns and calciners with SCR	All variables identified for kilns and calciners; AND 4. Ammonia injection rate; 5. Temperature of the inlet gas stream to SCR;
Kilns and calciners with SNCR	All variables identified for kilns and calciners; AND 4. Ammonia (or urea) injection rate; 5. Temperature of the inlet gas stream to SNCR;
Kilns and calciners with NSCR	All variables identified for kilns and calciners; AND 4. Natural gas (or other HC) injection rate.

TABLE 2-A (CONTINUED)

MEASURED VARIABLES FOR MAJOR NO_x SOURCES

EQUIPMENT TYPE : FLUID CATALYTIC CRACKING UNITS

EQUIPMENT	MEASURED VARIABLES
FCCUs (CO Boilers)	1. Stack NO_x concentration and exhaust flow rate; OR Stack NO_x, and O_2 concentrations, and fuel flow rate; 2. Status codes; 3. Production rate;
FCCUs with combustion modifications	All variables identified for refinery tail gas units.
FCCUs with SCR	All variables identified for refinery tail gas units; AND 4. Ammonia injection rate; 5. Temperature of the inlet gas stream to SCR;
FCCUs with SNCR	All variables identified for refinery tail gas units; AND 4. Ammonia (or urea) injection rate; 5. Temperature of the inlet gas stream to SNCR;
FCCUs with NSCR	All variables identified for refinery tail gas units; AND 4. Natural gas (or other HC) injection rate.

TABLE 2-B

REPORTED VARIABLES FOR ALL MAJOR NO_X SOURCES

EQUIPMENT	REPORTED VARIABLES
All Major NO_X sources	1. Total daily mass emissions from each source; 2. Daily Status codes.

RULE 2012 PROTOCOL- CHAPTER 3

LARGE SOURCES - CONTINUOUS PROCESS MONITORING SYSTEM (CPMS)

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CHAPTER 3 - LARGE SOURCES - CONTINUOUS PROCESS MONITORING SYSTEM (CPMS)

This chapter describes the methodologies for measuring and reporting emissions from large sources. For this category, the Facility Permit holder shall use Continuous Emissions Monitoring System (CEMS) or elect to use CPMS to measure NO_X emissions. The focal point shall be the emission factor (during the interim period only, January 1, 1994 to December 31, 1994 for Cycle 1 facilities and July 1, 1994 to July 1, 1995 for Cycle 2 facilities), concentration limit, or equipment-specific emission rate. Mass emissions shall be estimated by using the emission factor (e.g. lb/mm Btu), or concentration limit (e.g. ppmv converted to lb/mm Btu) and a throughput rate (typically fuel consumption adjusted for heating value).

Measurement and reporting requirements apply to variables used to calculate the NO_X emissions. These measured and process variables are found in Table 3-A. The reporting variables are found in Table 3-B.

In accordance with Rule 2012, the Facility Permit will specify either a concentration limit or an emission rate. One or more measured variables necessary to substantiate the equipment-specific emission rate shall be monitored and recorded. These measured variables are listed in Table 3-A. For sources subject to a concentration limit, only fuel usage or throughput is required to be measured by dedicated fuel meters or by any devices approved by the Executive Officer to be equivalent in accuracy, reliability, reproducibility, and timeliness.

Tables 3-C through 3-F list the rule-specific concentration limits, the emission fee billing factors, the unregulated default control efficiencies, and the standard oxygen concentrations.

The criteria for determining large source category is found in Table 1-B.

Starting January 1, 1994 (Cycle 1 facilities) and starting July 1, 1994 (Cycle 2 facilities), large-source NO_X emissions shall be allowed to use an interim reporting procedure to calculate and record on a monthly basis according to the requirements specified in Chapter 3, Subdivision D, Paragraph 1, and Chapter 3, Subdivision G, Paragraph 2 "Large Sources - Continuous Process Monitoring System (CPMS)" . On and after January 1, 1995 (Cycle 1 facilities) and July 1, 1995 (Cycle 2 facilities), the Facility Permit holder of each large source shall report consistent with all other applicable requirements specified in this chapter.

A. GENERAL REQUIREMENTS

1. The Facility Permit holder of a large NO_X source who has elected to use a concentration limit shall comply with any one of the following, in ppmv and over any continuous 60 minutes at each emission point:

   a. The Facility Permit holder shall be allowed to use the emission factors and/or control efficiencies listed in Tables 3-D, and 3-E or Table 1 of Rule 2002 and apply methodology presented in Subdivision 3, Paragraph C to derive a corresponding concentration limit; or

   b. If there is no applicable concentration limit and/or control efficiency, then the Facility Permit holder shall be allowed to request a manufacturer's guaranteed emission factors and/or control efficiency or a manufacturer's guaranteed concentration limit as part of the Facility Permit application; or

c. The Facility Permit holder shall be allowed to use applicable rule-specific concentration limit found in Table 3-C; or

d. The Facility Permit holder shall be allowed to use any other concentration limit as approved by the Executive Officer according to guidelines set forth in this chapter.

2. The Facility Permit holder of a large NO_X source who has elected to use a concentration limit shall calculate the mass emissions according to the methodology specified in Chapter 3, Subdivision D, Paragraph 2, Subparagraph a.

3. The Facility Permit holder of a large NO_x source who has elected to use an emission rate shall apply the methodology specified in Chapter 5 to derive an acceptable emission rate.

4. The Facility Permit holder of a large NO_x source who has elected to use an emission rate shall calculate the emissions according to the methodology specified in Chapter 3, Subdivision D, Paragraph 2, Subparagraph b.

5. The Facility Permit holder of each equipment shall measure and record fuel usage and one or more parametric variables in Table 3-A in order to substantiate the equipment-specific emission rate. As part of the Facility Permit application review, the Executive Officer shall modify the list of Facility Permit holder-selected variables.

6. Fuel flow measuring devices used for obtaining stack flow in conjunction with F-factors and stack flow monitors shall be tested as installed for relative accuracy using the following methods:

a. If the facility uses a fuel flow meter in conjunction with F-factors to determine stack gas volumetric flow rate, the relative accuracy of the fuel flow meter must be determined using District reference Methods 1-4 and a three-run relative accuracy audit (RAA) at normal operating load. The accuracy of the fuel flow measuring system must be determined using the following equation:

$$A = \frac{(C_m - C_a)}{C_a} \times 100 \qquad \text{(Eq. 15a)}$$

where:

A = accuracy of the fuel flow meter (%)

C_m = average flow rate response (scfh)

C_a = average reference method flow rate (scfh)

The value of fuel flow meter accuracy, as defined in Eq. 15a, shall be less than or equal to 15%.

b. If the facility uses a stack flow meter to determine stack gas volumetric flow rate, the relative accuracy of the stack flow meter must be determined using District reference Methods 1-4 and a three-run relative accuracy audit (RAA). The accuracy of the fuel flow measuring system must be determined using the procedure outlined in Chapter 3, (A)(6)(a) above. The accuracy of the stack flow meter shall be less than or equal to 15%.

c. Other acceptable alternatives to the above procedures used to determine the relative accuracy of the facility fuel flow meter or stack flow meter are listed under Chapter 3, Subdivision H.

7. Fuel meters or any devices approved by the Executive Officer to be equivalent in accuracy, reliability, reproducibility, and timeliness, shall be non-resettable and tamper proof. The seals installed by the manufacturer shall be intact to prove the integrity of the measuring device.

Meters which are unsealed for maintenance or repairs shall be resealed by an authorized manufacturers representative.

8. The Facility Permit holder of each large NO_X source shall monitor, report, and maintain the records on a monthly basis the type and quantity of fuel burned, in units of millions of standard cubic feet per month (mmscf per month) for gaseous fuels or thousand gallons per month (mgal per month) for liquid fuels, expressed to at least three significant figures.

9. Monthly NO_X mass emissions shall be reported to the District's NO_X Central Station Computer according to the requirements specified in Chapter 3, Subdivision G.

B. MONITORING SYSTEMS

1. Operational Requirements

The CPMS shall be operated and data recorded during all periods of operation of the equipment including periods of start-up, shutdown, malfunction or emergency conditions, except for CPMS breakdowns and repairs.

2. Performance Standard

All CPMS at each equipment shall, at a minimum, be able to measure the fuel usage once every fifteen minutes. Such measured data shall be accumulated and recorded to represent the monthly fuel usage as specified in Paragraphs B.3.

3. Information Required for Each Monthly Interval

All CPMS at each equipment shall, at a minimum, measure and totalize the following data points for each successive monthly period, expressed to at least three significant figures, and at equally spaced intervals thereafter, except where noted:

a. Fuel usage in units of million standard cubic feet per month (mmscf/mo) for gaseous fuels, or thousand gallons per month (mgal/mo) for liquid fuels. Alternatively, the fuel usage may be calculated from stack gas volumetric flow rates totalized over a month and oxygen concentration, in which case the Facility Permit holder shall measure:

   i. Oxygen concentration in the stack in units of percent if required for calculation of the stack gas flow rate.

   ii. Volumetric flow rate of stack gases in units of dry standard cubic feet per month. Standard gas conditions are defined as a temperature at 68°F and one atmosphere of pressure.

b. One or more process variables specified in Table 3-A, if the Facility Permit holder elects for an equipment-specific emission rate.

C. CONCENTRATION LIMIT CALCULATION

Pursuant to the election condition requirements in Rule 2012 (f), the Facility Permit holder shall use the equation provided in this section to calculate the concentration limit. Equation 15 applies to the Facility Permit holder requesting that the Emission Fee Billing factor in Table 3-D, the emission factor specified in Table 1, Rule 2002 - Baselines and Rates of Reduction for NO_x/SO_x and/or the control efficiency in Table 3-E be converted into a concentration limit.

$$PPMV_c = 0.8368x10^7 \text{ x } (20.9\text{-}b/20.9) \text{ x } \sum_{j=1}^{r} EF_j \ (1\text{-}EFF_i/100)/(F_{di} \text{ x } V_j) \qquad \text{(Eq.15)}$$

where:

$PPMV_c$ = The equipment-specific concentration limit corrected at applicable standard oxygen concentration found in Table 3-F or rule-specific concentration limit found in Table 3-C.

EF_j = The equipment-specific EFB emission factor (lb/mmscf or lb/mgal) found in Table 3-D or emission factor found in Table 1 of Rule 2002 or reported value of emission factor. The emission factor found in Table 1 of Rule 2002 may or may not include the appropriate control efficiency.

EFF_j = The equipment-specific control efficiency (%), found in Table 3-E or proposed by the Facility Permit holder.

b = The standard oxygen concentration (%) found in Table 3-F.

F_{dj} = The fuel-specific dry F factor, the ratio of the dry gas volume of the products of combustion to the heat content of the fuel(dscf/mmBtu) specified in 40 CFR Part 60, Appendix A, Method 19.

V = The higher heating value for each type of fuel (mmBtu/mmscf or mmBtu/mgal) found in Table 3-D.

j = Each type of equipment in a large NO_x source sharing a fuel meter and identical concentration limit at standard oxygen concentration.

r = The total number of equipment in a large NO_x source sharing a fuel meter and identical concentration limit at standard oxygen concentration.

Example Calculation: Natural-Gas Fired Boiler with Lo-NO_X Burner		
EF	=	130 lb/mmsf
V	=	1,050 mmBtu/mmscf
EFF	=	35%
b	=	3%
F_d	=	8,710 dscf/mmBtu
$PPMV_c$	=	130 (1 - 35/100) x [(20.9 - 3)/20.9] x 0.8368 x 10^7/(8,710 x 1,050) =70 ppmv

D. EMISSION CALCULATION FOR REPORTED DATA

1. Monthly Mass Emissions for Interim Periods

Pursuant to Rule 2012 (f) (1), between January 1, 1994 and December 31, 1994 for Cycle 1 facilities, and between July 1, 1994 and June 30, 1995 for Cycle 2 facilities, the monthly emission of each large source shall be calculated and recorded according to:

$$E_{ip} = \sum_{j=1}^{r} EF_{sj} \times d_j \qquad \text{(Eq.16)}$$

where:

E_{ip} = The monthly mass emission of nitrogen oxides for interim period (lb/month).

EF_{sj} = The starting emission factor used to calculate source emissions in the initial allocation, as specified in Table 1 of Rule 2002 - Allocations for NO_x/SO_x (lb/mmscf, lb/mgal).

d_j = The monthly metered fuel usage for each type of fuel recorded as mmscf/ month or mgal/month.

j = Each type of fuel used, or material processed or produced by a large NOx source

r = The total number of fuel types used, or materials processed or produced by a large NOx source

Example calculation: Boiler burning natural gas, rated 40 mmBtu/hr, in compliance with Rule 1146.

Applicable starting year emission factor	=	49.18 lb/mmscf
Monthly fuel usage	=	20 mmscf per month
E_{ip}	=	(49.18) x (20) = 983.6 lb/month

2. Monthly Mass Emissions for Normal Operating Hours

a. When the Facility Permit holder elects to use the concentration limit, the monthly mass emission shall be calculated and recorded according to one of the following equations:

i Use the F-factor approach for oxygen, except in cases where enriched oxygen is used, non-fuel sources of carbon dioxide are present (e.g., lime kilns and calciners), or the oxygen content of the stack gas is 19 percent or greater. Sources that are permitted to demonstrate compliance using the procedures in Rule 2012, Appendix A, Chapter 5, Subdivision H shall use the following equation to calculate and record nitrogen oxides mass emission rate even if the oxygen stack gas is 19 percent or greater. The following equation shall be used to calculate and record nitrogen oxides mass emission rate:

$$E_k = PPMV_{O2} \quad [20.9/(20.9 - b)] \times 1.195 \times 10^{-7} \times \sum_{j=1}^{r} (F_{dj} \times d_j \times V_j) \qquad \text{(Eq.17)}$$

where:

E_k	=	The monthly mass emission of nitrogen oxides (lb/month).
$PPMV_{O2}$	=	The RECLAIM concentration limit as listed in the Facility Permit. (ppmv) and based on standardized oxygen concentration in the exhaust stream..
b	=	The standard concentrations of oxygen as listed in the Facility Permit or as found in Table 3-F. (%).
r	=	The number of different types of fuel.
j	=	Each type of fuel.
$F_{d\,j}$	=	The oxygen-based dry F factor for oxygen for each type of fuel, the ratio of the dry gas volume of the products of combustion to the heat content of the fuel (dscf/mmBtu) specified in 40 CFR Part 60, Appendix A, Method 19.
d_j	=	The monthly fuel usage for each type of fuel recorded by the fuel totalizer (mmscf per month

or mgal per month).

V_j = The higher heating value of the fuel for each type of fuel found in Table 3-D (mmBtu/mmscf or mmBtu/mgal) or determined by a continuous analyzer.

The product (d_j x V_j) shall have units of mmBtu per month (mmBtu/month).

For non-standard fuels that are not listed in 40 CFR Part 60, Appendix A, Method 19, a constant F-factor and heating value may be used if the Facility Permit holder demonstrates to the Executive Officer that the natural gas, fuel oil, or other fuels have stable F-factors and gross heating values. A stable F-factor or gross heating value is defined as not varying by more than + or - 2.5% from the proposed constant value. For the fuels listed in 40 CFR 60, Appendix A, Method 19, Table 19-1, the F-factors are assumed to be stable at the value cited in Table 19-1. Any F-factor cited in Regulation XX shall supersede the F-factor in Table 19-1. For fuels not listed in the citations above, but which the Facility Permit holder demonstrates that the source-specific F-factor meets the same stability criteria, periodic reporting of F-factor may be accepted and the adequacy of the frequency of analyses shall be demonstrated by the Facility Permit operator such that the probability that any given analysis will differ from the previous analysis by more than 5% (relative to the previous analysis) or less than 5%. Analysis records shall be maintained, including all charts and laboratory notes.

For non-standard fuels that are not listed in 40 CFR Part 60, Appendix A, Method 19 and do not satisfy the criteria for constant F-factor and heating value, the fuels must be analyzed on a continuous basis using gas chromatographs or other continuous technique that is approved by the Executive Officer. The continuous technique employed shall be capable of providing at a minimum a reading every fifteen-minute period.

ii. If the F-factor approach for oxygen can not be used, use the F-factor approach for carbon dioxide as specified in 40 CFR Part 60, Appendix A, Method 19, except in cases where the carbon dioxide concentration is less than one volume percent dry, non-fuel sources of carbon dioxide are present (e.g., lime kilns and calciners), or non-metered sources of fuel are present (e.g., afterburners). The following equation shall be used to calculate and record nitrogen oxides mass emission rate:

$$E_k = PPMV_{CO2} \times (100/\%CO_2) \times 1.195 \times 10^{-7} \times \sum_{j=1}^{r} (F_{dj} \times d_j \times V_j) \quad \text{(Eq.17a)}$$

Where:

E_k	=	The monthly mass emission of nitrogen oxides (lb/month).
$PPMV_{CO2}$	=	The RECLAIM concentration limit as listed in the Facility Permit (ppmv) and based on standardized carbon dioxide concentration in the exhaust stream.
$\%CO_2$	=	The standard concentrations of stack gas carbon dioxide as listed in the Facility Permit.
r	=	The number of different types of fuel.
j	=	Each type of fuel.
$F_{d\,j}$	=	The dry F factor for carbon dioxide for each type of fuel, the ratio of the dry gas volume of the products of combustion to the heat content of the fuel (dscf/mmBtu) specified in 40 CFR Part 60, Appendix A, Method 19.
d_j	=	The monthly fuel usage for each type of fuel recorded by the fuel totalizer (mmscf per month or mgal per month).
V_j	=	The higher heating value of the fuel for each type of fuel found in Table 3-D (mmBtu/mmscf or mmBtu/mgal)) or determined by a continuous analyzer.

For non-standard fuels that are not listed in 40 CFR Part 60, Appendix A, Method 19, a constant F-factor and heating value may be used if the Facility Permit holder demonstrates to the Executive Officer that the natural gas, fuel oil, or other fuels have stable F-factors and gross heating values. A stable F-factor or gross heating value is defined as not varying by more than + or - 2.5% from the proposed constant value. For the fuels listed in 40 CFR 60, Appendix A, Method 19, Table 19-1, the F-factors are assumed to be stable at the value cited in Table 19-1. Any F-factor cited in Regulation XX shall supersede the F-factor in Table 19-1. For fuels not listed in the citations above, but which the Facility Permit holder demonstrates that the source-specific F-factor meets the same stability criteria, periodic reporting of F-factor may be accepted and the adequacy of the frequency of analyses shall be demonstrated by the Facility Permit operator such that the probability that any given analysis will differ from the previous analysis by more than 5% (relative to the previous analysis) or less than 5%. Analysis records shall be maintained, including all charts and laboratory notes.

For non-standard fuels that are not listed in 40 CFR Part 60, Appendix A, Method 19 and do not satisfy the criteria for constant F-factor and heating value, the fuels must be analyzed on a continuous basis using gas chromatographs or other continuous technique that is approved by the Executive Officer. The continuous technique employed shall be capable of providing at a minimum a reading every fifteen-minute period.

iii. If the F-factor approach for carbon dioxide can not be used, the nitrogen oxides mass emission rate shall be determined based on actual monthly stack flow rate from a continuous stack flow monitor and concentration limit at stack conditions as listed in the Facility Permit. The mass emission rate shall be determined by the following equation:

$$E_k = PPMV_{ST} \times 1.195 \times 10^{-7} \times \sum_{j=1}^{N} F_j \qquad \text{(Eq. 17b)}$$

where:

E_k = The monthly mass emission of nitrogen oxides (lb/month).

$PPMV_{ST}$ = The concentration limit at stack condition as listed in the Facility Permit (ppmv).

F_j = Total monthly stack flow rate (scf/month) of stack j.

N = Number of exhaust stacks.

For systems that record hourly exhaust flow rate data, the total monthly stack flow rate shall be determined by the following equation:

$$F_j = \sum_{i=1}^{M} H_{ij} \qquad \text{(Eq. 17c)}$$

F_j = Total monthly stack flow rate (scf/month) of stack j.

H_{ij} = Hourly stack flow rate (scf/hour) of stack j.

M = Total number of hours for the month

Whenever valid stack flow rate data is not obtained for an hour, the Facility Permit holder shall calculate substitute data using the missing data procedures applicable to flow as set forth in Subdivision K, Paragraph 2 of this chapter.

b. When the Facility Permit holder elects to use the emission rate, the monthly emission shall be calculated and recorded according to:

$$E_k = \sum^{r} d_i \times V_i \times ER_i \qquad \text{(Eq.18)}$$

j=1

where:

E_k = The monthly mass emission of nitrogen oxides (lb/month).

d_j = The monthly fuel usage for each type of fuel recorded by the fuel totalizer (mmscf/month or mgal/month) or the monthly amount of materials produced or processed, depending to the units of the equipment specific emission rate.

ER_j = The equipment-specific emission rate proposed by the Facility Permit holder and determined according to Chapter 5, Subdivision E (lb/mmBtu).

V_j = The higher heating value of each type of fuel (mmBtu/mmscf or mmBtu/mgal). This equals 1 if ERj is not dependent on fuel combustion.

Example Calculation:		
y	=	Each type of fuel.
r	=	The number of type of fuel consumed per month
Boiler		
ER_c	=	200 lb/mmscf requested for uncontrolled, natural gas fired boiler
d	=	1 mmscf per month
E_k	=	ER_c x d = 200 x 1
E_k	=	200 lb/month
ICE		
ER_c	=	500 lb/1000 gal requested for uncontrolled, natural gas fired ICE
d	=	600 gal/month
E_k	=	ER_c x d
	=	500 lb/1000 x 600 gal/month
	=	300 lb/month
Total E_k	=	200 + 300 lb/month
	=	500 lb/month

3. Monthly Mass Emissions during Startup or Shutdown Periods

The Facility Permit holder of a large source with startup or shutdown periods at least 6 hours in duration shall apply the following methodology to determine the emissions during startup and shutdown periods:

a. During equipment startup or shutdown the Facility Permit holder shall apply the EFB emission factor specified in Table 3-D; or

b. If the emission factors in Table 3-D do not reflect the emission factors during startup and shutdown periods, the Facility Permit holder shall propose emission factors for the approval of the Executive Officer and shall submit source test data to substantiate the proposed emission factors. The monthly emissions during startup and shutdown periods shall be calculated and reported according to:

$$E_{st} = \sum_{j=1}^{r} D_{stj} \times EF_{stj} \qquad \text{(Eq.19)}$$

$$E_{sh} = \sum_{j=1}^{r} D_{sh} \times EF_{sh} \qquad \text{(Eq.20)}$$

where:

E_{st} = The monthly mass emission of nitrogen oxides during startup period (lb/month).

Dstj = The monthly fuel usage for each type of fuel during startup period (mmscf/month or mgal/month), or the amount of materials produced or processed per month depending on the units or proposed emission factors or emission rates..

EFstj = The EFB or Facility Permit holder-specified emission factor or emission rate during startup period (lb/mmscf or lb/mgal

where:

E_{sh} = The monthly mass emission of nitrogen oxides during shutdown period (lb/month).

Dshj = The monthly fuel usage for each type of fuel during shutdown period (mmscf/month or mgal/month) or the amount of materials produced or processed per month, depending on the units of proposed emission factors or emission rates.

EFshj = The EFB or Facility Permit holder-specified emission factor or emission rate during shutdown period (lb/mmscf or lb/mgal).

j = Each type of fuel or material processed or produced

r = The number of each type of fuel consumed per month or the number of material processed or produced per month.

E. TOTAL MONTHLY MASS EMISSION CALCULATION

The total monthly mass emission shall be calculated and recorded for each equipment according to:

$$E = E_k + E_m + E_{st} + E_{sh} \qquad \text{(Eq. 21)}$$

Where:

E = The monthly mass emission of nitrogen oxides (lb/month).

E_k = The monthly mass emission calculated using measured data during normal operation (lb/month).

E_m = The monthly mass emission calculated using substitute data during normal operation (lb/month).

E_{st} = The monthly mass emission calculated during startup period (lb/month).

E_{sh} = The monthly mass emission calculated during shutdown period (lb/month).

Example Calculation:				
E_k	=	130 lb/10^6 scf x 420 scf/hr x 480 hr/mo	=	26.2 lb/month
E_m	=	161 lb/10^6 scf x 300 scf/hr x 3hr/day	=	.1449 lb/month
E_{st}	=	130 lb/10^6 scf x 100 scf/hr x 3hr/day	=	.0390 lb/month
E_{sh}	=	130 lb/10^6 scf x 50 scf/hr x 2 hr/day	=	.0130 lb/month
E	=	$E_k + E_m + E_{st} + E_{sh}$ = 26.2 + .1449 + .0390 +.0130	=	26.4 lb/month

F. FLOW DETERMINATION TEST METHODS

1. District Methods 2.1 and 2.3 shall be used to determine the stack gas volumetric flow rate.

2. For District Method 2.1, District Method 1.1 shall be used to select the sampling site and the number of traverse points.

3. District Method 3.1 shall be used for diluent gas (O_2 or CO_2) concentration and stack gas density determination.

4. District Method 4.1 shall be used for moisture determination of stack gas.

G. REPORTING PROCEDURES

1. The total fuel usage data for all large sources in any facility without a RTU or modem shall be reported in a format approved by the Executive Officer.

2. For each equipment the following information shall be stored on-site in a format approved by the Executive Officer:

   a. Calendar dates covered in the reporting period;

   b. Monthly mass emissions for each equipment ;

   c. Identification of the equipment operating days for which a sufficient number of valid data points has not been taken; reasons for not taking sufficient data; and a description of corrective action taken;

d. Identification of F_d or Fw factor for each type of fuel used for calculation and the type of fuel burned;

e. Any changes made in type of fuel used and F_d factor, if applicable.

H. ALTERNATIVE QUALITY ASSURANCE PROCEDURES

1. Emission Stack Flow Rate Determination

In the event that more than one source vents to a common stack, the alternative reference method for determining individual source flow rates shall be EPA Method 19. The orifice plates used in every unit vented to a common stack shall meet the requirements in Chapter 3, Subdivision H, Paragraph 3.

2. Quality Assurance Procedures for Volumetric Flow Measurement System

a. Each volumetric flow measurement system shall be audited at least once each calendar year. Successive audits shall occur no closer than six months or after any modification to the process which would significantly alter the flow.

b. If the volumetric flow measurement system is found to be out of calibration by 15 percent or greater, then recalculation of the flow measurement must be performed from the last audit date to the current audit date.

3. Quality Assurance for Orifice Plate Measurements

Each orifice plate used to measure the fuel gas flow rate shall be removed from the gas supply line for an inspection once every 12 months, if the orifice cannot be checked using Reference Methods or other methods that can show traceability to NIST standards. However, with the prior approval of the Executive Officer, orifice plates may be inspected not less than once every 36 months provided the Facility Permit holder demonstrates to the Executive Officer that orifice plates used for 36 months or longer meet the specifications set forth in this paragraph. This demonstration shall be completed by July 1, 1995 or within one year for facilities that enter RECLAIM on and after July 1, 1994. The following items shall be subject to inspection:

a. Each orifice plate shall be visually inspected for any nicks, dents, corrosion, erosion, or any other signs of damage according to the orifice plate manufacturer's specifications.

b. The diameter of each orifice shall be measured using the method recommended by the orifice plate manufacture.

c. The flatness of the orifice plate shall be checked according to the orifice plate manufacturer's instructions. The departure from flatness of an orifice plate shall not exceed 0.010 inches per inch of dam height (D-d/2) along any diameter. Here D is the inside pipe diameter and d is the orifice diameter at its narrowest constriction.

d. The pressure gauge or other device measuring pressure drop across the orifice shall be calibrated against a manometer, and shall be replaced if it deviates more than ±2 percent across the range.

e. The surface roughness shall be measured using the method recommended by the orifice plate manufacturer. The surface roughness of an orifice plate shall not exceed 50 micro inches.

f. The upstream edge of the measuring orifice shall be square and sharp so that it shall not show a beam of light when checked with an orifice gauge.

g. In centering orifice plates, the orifice shall be concentric with the inside of the meter tube or fitting. The concentricity shall be maintained within 3 percent of the inside diameter of the tube or fitting along all diameters.

h. Any other calibration tests specified by the orifice plate manufacturer shall be conducted at this time. If an orifice fails to meet any of the manufacturer's specifications, it shall be replaced within two weeks.

4. Alternative Relative Accuracy Audit

This section is applicable to facility permit holders who may choose to determine the relative accuracy of the fuel flow meters by a direct comparison to a calibrated fuel flow meter (proving meter) instead of conducting velocity traverse reference method tests. The following general requirements apply to this alternative procedure:

a. The alternative RAA shall be conducted by an independent testing laboratory in accordance with NIST traceable industry standards. A non-independent testing laboratory may be used if the laboratory is regulated by the California Public Utilities Commission.

b. The results shall identify as-found and as-left accuracy of pressure and temperature corrected fuel flow rates. Perform all calculations at consistent temperature and pressure as prescribed by the applicable procedure. All fuel flow rates measured by the fuel flow meters must be converted to standard RECLAIM conditions, which are 68°F and one atmosphere pressure.

c. The value of as-left accuracy, as defined in Eq. 22a, shall be 2.5% or less.

d. The alternative RAA must include at least one run at each of two operating loads. These operating loads must be within 10 percent of the lowest historical operating load and 60 to 100 percent of the maximum operating range of the fuel flow meter. The alternative RAA can include one run at one operating load if the testing laboratory is regulated by the California Public Utilities Commission, and is subject to a more stringent as-left accuracy, as defined in Eq. 22a, than specified in subparagraph (H)(4)(c).

e. If the meter is bypassed during the alternative RAA, missing data procedures shall apply.

The following conditions and procedures apply to specific configurations that may be employed to conduct the above mentioned alternative RAA:

f. Procedure 1: Fuel Flow Meters in Series

Fuel flow meter accuracy may be determined by comparing fuel flow rate from a proving meter (test meter) placed in series with the facility fuel flow meter. The proving meter may be either permanent or removable, however, it must be designed and installed in accordance with recognized industry standards. The proving meter's accuracy must be verified to NIST standards prior to series meter proof. Calibration procedures as prescribed by 40 CFR Part 75, Appendix E and the ones cited below may be used to calibrate such fuel flow meters. The accuracy as determined by the following equation must be less than or equal to 2.5% of the upper range value of the flow meter:

$$A = |R\ B| / URV \times 100 \qquad \text{(Eq. 22a)}$$

where:

A	=	flow meter accuracy
R	=	average of flow measurements of the proving meter at each load
B	=	tested at each load average of flow measurements of the meter being
URV	=	upper range value of fuel flow meter being tested

g. Procedure 2: Meter Swapping

The facility fuel flow meter may be swapped with a factory calibrated meter. The calibration procedures outlined in 40 CFR Part 75, Appendix E and the ones cited below may be used for this purpose. Meter calibrations shall be conducted at the flow rates given in the recognized industry standards. The recognized industry standards for calibration are as follows:

Meter Type	Standard
Diaphragm	ANSI B 109.1 or 109.2 (3rd. edition, 1992)
Rotary	ANSI B109.3 (3rd. edition, 1992)
Turbine	AGA Report No. 7 (2nd. edition, 1996)

Orifice	AGA Report No. 3, Part 1 and 2 (1990, 1991) API 14.3 GPA 8185-90

The minimum installation requirements are as follows:

Meter Type	Standard
Diaphragm	ANSI B 109.1 or 109.2, Part V
Rotary	ANSI B109.3, Part V
Turbine	AGA Report No. 7, Section 3
Orifice	AGA Report No. 3, Part 2, Section 2.6

The above calibration standards apply to both Subparagraph (H)(4)(f) and Subparagraph (H)(4)(g). The above installation requirements apply only to Subparagraph (H)(4)(g).

I. MISSING AND INVALID DATA PROCEDURES

1. For each large source or large sources using a common fuel meter or equivalent monitoring device, the Facility Permit holder shall provide substitute data as described below whenever a valid month of fuel usage data or the amount of production or process feed has not been obtained and recorded. Alternative data is acceptable for substitution if the Facility Permit holder can demonstrate to the Executive Officer that the alternative system is fully operational during meter down time and within + or- 2% accuracy.

2. Whenever data from the process monitor is not available or not recorded for the affected equipment or when the equipment is not operated within the parameter range specified in the Facility Permit, the Facility Permit holder shall calculate substitute data for each month according to the following procedures.

   a. For a missing data period less than or equal to one month, substitute data shall be calculated using the large source(s) average monthly fuel usage for the previous 12 months.

   b. For a missing data period greater than one month, substitute data shall be calculated using the large source(s) highest monthly fuel usage data for the previous 12 months.

   c. For a missing data period greater than two months, or if the facility has no records, substitute data shall be calculated using 100 percent uptime during the substitution period and the large source(s) maximum rated capacity and uncontrolled emission factor for each month of missing data.

   d. For a process monitor which uses a gas chromatograph or equivalent continuous method to continuously determine the F-factor and higher heating value of the fuel (Rule 2012, Appendix

A, Chapter 3, Subdivision D.2.a.i), the Facility Permit holder shall use the stack gas flow rate missing data substitution procedure for major sources (Rule 2011 or 2012, Appendix A, Chapter 2, Subdivision E.2).

J. FUEL METER SHARING

1. A single totalizing fuel meter shall be allowed to measure the cumulative fuel usage for more than one equipment in a large NO_X source provided that each equipment has the same concentration limit, emission rate, or emission factor as specified in the Facility Permit and that any equipment in a large NO_x source does not use the annual heat input in order to be classified from a major source to a large source.

2. One or more pieces of equipment in a large NO_x source shall be allowed to share the fuel totalizing meter provided that each equipment elects for the same concentration limit, emission rate, or emission factor as specified in the Facility Permit.

3. Fuel meter sharing for the interim period shall be allowed for those equipment in a large NO_X source with the same emission factor, emission rate, or concentration limit.

K. PROCEDURES FOR LARGE SOURCES MONITORED BY CEMS

The following requirements are applicable when the Facility Permit holder chooses CEMS as a monitoring alternative for large sources.

1. Calculate monthly mass emissions by summing daily mass emissions which are obtained using procedures set forth in Appendix A, Chapter 2, except that the missing data procedures set forth below shall be used whenever valid data is not obtained:

2. Missing Data Procedures for Large Sources Monitored by CEMS

    a. Percentage of data availability shall be calculated according to procedures set forth in Appendix A, Chapter 2, Subdivision E, subparagraph 1a.

    b. Whenever concentration or flow data from the CEMS have been available and recorded for 95 percent or more of the total operating hours of the affected piece of equipment during the previous 365 days, the Facility Permit holder shall calculate substitute data for each hour, when valid data has not been obtained, according to the following procedures.

        i. For a cumulative missing data period less than or equal to 24 hours in a month, substitute data shall be calculated using the average hourly-recorded CEMS value from the previous month. If no emissions occurred during the previous month, clause (K)(2)(c)(iii) shall apply.

ii. For a cumulative missing data period greater than 24 hours in a month, substitute data shall be calculated using the maximum hourly-recorded CEMS value from the previous month. If no emissions occurred during the previous month, clause (K)(2)(c)(iii) shall apply.

c. Whenever concentration or flow data from the CEMS have been available for 90-percent or more but less than 95-percent of the total operating hours of the affected piece of equipment during the previous 365 days, the Facility Permit holder shall calculate substitute data for each hour, when valid data has not been obtained, according to the following procedures.

i. For a cumulative missing data period less than or equal to 24 hours in a month, substitute data shall be calculated using the average hourly-recorded CEMS value from the previous month. If no emissions occurred during the previous month, clause (K)(2)(c)(iii) shall apply.

ii. For a cumulative missing data period greater than 24 hours but less than or equal to 168 hours in a month, substitute data shall be calculated using the maximum hourly-recorded CEMS value from the previous month. If no emissions occurred during the previous month, clause (K)(2)(c)(iii) shall apply.

iii. For a cumulative missing data period greater than 168 hours in a month, substitute data shall be calculated using the maximum hourly-recorded CEMS value from the previous 12 months or during the service of the monitoring system, whichever is shorter. If no emissions occurred during the previous 12 months, subparagraph (K)(2)(d) shall apply

d. Whenever concentration or flow data from the CEMS have been available for less than 90% of the total operating hours of the affected piece of equipment during the previous 365 days, the Facility Permit holder shall calculate substitute data for each hour using the maximum hourly-recorded CEMS value during the service of the monitoring system.

e. Whenever prior CEMS data have not been available (0% availability), monthly mass emissions shall be calculated using Appendix A, Chapter 3, Subdivision D. For those sources operating without a fuel meter, process rate meter, or production rate meter, monthly mass emissions shall be calculated pursuant to Appendix A, Chapter 3, Subdivision I, Subparagraph 2c.

Table 3-A

MEASURED AND PROCESS VARIABLES FOR LARGE NO_X SOURCES

EQUIPMENT TYPE : BOILERS

EQUIPMENT	MEASURED VARIABLES
Boilers	1. Fuel flow rate or exhaust flow rate (for sources with stack flow monitors); 2. Steam production rate (for sources permitted with emission rates corresponding to the measured variable);
Boilers with low NO_x burners	All variables identified for boilers.
Boilers with staged combustion	All variables identified for boilers.
Boilers with FGR	All variables identified for boilers; AND 3. Flue gas recirculation rate.
Boilers with SCR	All variables identified for boilers; AND 3. Ammonia injection rate; 4. Temperature of the inlet gas stream to SCR;
Boilers with SNCR	All variables identified for boilers; AND 3. Ammonia (or urea) injection rate; 4. Temperature of the inlet gas stream to SNCR;
Boilers with NSCR	All variables identified for boilers; AND 3. Natural gas (or other HC) injection rate.

EQUIPMENT TYPE : FURNACES

EQUIPMENT	MEASURED VARIABLES
Furnaces	1. Fuel flow rate or exhaust flow rate (for sources with stack flow monitors); 2. Production rate (for sources permitted with emission rates corresponding to the measured variable);
Furnaces with low NO_x burners	All variables identified for furnaces.
Furnaces with combustion modification	All variables identified for furnaces.
Furnaces with SCR	All variables identified for furnaces; AND 3. Ammonia injection rate; 4. Temperature of the inlet gas stream to SCR;
Furnaces with SNCR	All variables identified for furnaces; AND 3. Ammonia (or urea) injection rate; 4. Temperature of the inlet gas stream to SNCR;

Table 3-A (CONTINUED)

MEASURED AND PROCESS VARIABLES FOR LARGE NO_X SOURCES

EQUIPMENT TYPE : OVENS

EQUIPMENT	MEASURED VARIABLES
Ovens	1. Fuel flow rate or exhaust flow rate (for sources with stack flow monitors); 2. Production rate (for sources permitted with emission rates corresponding to the measured variable);
Ovens with low NO_x burners	All variables identified for ovens.
Ovens with combustion modification	All variables identified for ovens.
Ovens with SCR	All variables identified for ovens; AND 3. Ammonia injection rate; 4. Temperature of the inlet gas stream to SCR;
Ovens with SNCR	All variables identified for ovens; AND 3. Ammonia (or urea) injection rate; 4. Temperature of the inlet gas stream to SNCR;

EQUIPMENT TYPE : DRYERS

EQUIPMENT	MEASURED VARIABLES
Dryers	1. Fuel flow rate or exhaust flow rate (for sources with stack flow monitors); 2. Production rate (for sources permitted with emission rates corresponding to the measured variable);
Dryers with low NO_x burners	All variables identified for dryers.
Dryers with combustion modification	All variables identified for dryers.
Dryers with FGR	All variables identified for dryers; AND 3. Flue gas recirculation rate.
Dryers with SCR	All variables identified for dryers; AND 3. Ammonia injection rate; 4. Temperature of the inlet gas stream to SCR;
Dryers with SNCR	All variables identified for dryers; AND 3. Ammonia (or urea) injection rate; 4. Temperature of the inlet gas stream to SNCR;
Dryers with NSCR	All variables identified for dryers; AND 3. Natural gas (or other HC) injection rate.

Table 3-A (CONTINUED)

MEASURED AND PROCESS VARIABLES FOR LARGE NO_X SOURCES

EQUIPMENT TYPE : PROCESS HEATERS

EQUIPMENT	MEASURED VARIABLES
Process heaters	1. Fuel flow rate or exhaust flow rate (for sources with stack flow monitors); 2. Process rate (for sources permitted with emission rates corresponding to the measured variable);
Process heaters with low NO_x burners	All variables identified for process heaters.
Process heaters with combustion.modification	All variables identified for process heaters.
Process heaters with FGR	All variables identified for process heaters; AND 3. Flue gas recirculation rate.
Process heaters with SCR	All variables identified for process heaters; AND 3. Ammonia injection rate; 4. Temperature of the inlet gas stream to SCR;
Process heaters with SNCR	All variables identified for process heaters; AND 3. Ammonia (or urea) injection rate; 4. Temperature of the inlet gas stream to SNCR;
Process heaters with NSCR	All variables identified for process heaters; AND 3. Natural gas (or other HC) injection rate.
Process heaters with water (or steam) injection	All variables identified for process heaters; AND 3. Water (or steam) injection rate.

EQUIPMENT TYPE : INCINERATORS

EQUIPMENT	MEASURED VARIABLES
Incinerators	1. Fuel flow rate or exhaust flow rate (for sources with stack flow monitors); 2. Process rate (for sources permitted with emission rates corresponding to the measured variable);
Incinerators with SCR	All variables identified for incinerators; AND 3. Ammonia injection rate; 4. Temperature of the inlet gas stream to SCR;
Incinerators with SNCR	All variables identified for incinerators; AND 3 Ammonia (or urea) injection rate; 4. Temperature of the inlet gas stream to SNCR;

EQUIPMENT TYPE : TEST CELLS

EQUIPMENT	MEASURED VARIABLES
Test cells	1. Fuel flow rate or exhaust flow rate (for sources with stack flow monitors); 2. Shaft horsepower output (for sources permitted with emission rates corresponding to the measured variable);

Table 3-A (CONTINUED)

EQUIPMENT TYPE : TEST CELLS

Test cells with SCR	All variables identified for test cells; AND 3. Ammonia injection rate; 4. Ammonia slip
Test cells with Packed Chemical Scrubber	All variables identified for test cells; AND 3. Chemical injection rate.

EQUIPMENT TYPE : INTERNAL COMBUSTION ENGINES

EQUIPMENT	MEASURED VARIABLES
Internal combustion engines	1. Fuel flow rate or exhaust flow rate (for sources with stack flow monitors); 2. Throttle setting (for sources permitted with emission rates corresponding to the measured variable)
Internal combustion engines with combustion modification	All variables identified for internal combustion engines.
Internal combustion engines with Injection Timing Retard 4 degree	All variables identified for internal combustion engines.
Internal combustion engines with turbocharger, aftercooler, intercooler.	All variables identified for internal combustion engines.
Internal combustion engines with SCR	All variables identified for internal combustion engines; AND 3. Ammonia injection rate; 4. Temperature of the inlet gas stream to SCR;
Internal combustion engines with NSCR	All variables identified for internal combustion engines; AND 3. Natural gas (or other HC) injection rate.

EQUIPMENT TYPE : GAS TURBINES

EQUIPMENT	MEASURED VARIABLES
Gas turbines	1. Fuel flow rate or exhaust flow rate (for sources with stack flow monitors); 2. Shaft horsepower output (for sources permitted with emission rates corresponding to the measured variable);
Gas turbines with Water or Steam Injection	All variables identified for gas turbines; AND 3. Water or steam injection rate;
Gas turbines with SCR and Steam Injection	All variables identified for gas turbines; AND 3. Ammonia injection rate; 4. Steam injection rate
Gas turbines with SCR and Water Injection	All variables identified for gas turbines; AND 3. Ammonia injection rate; 4. Water injection rate

Table 3-A (CONTINUED)

MEASURED AND PROCESS VARIABLES FOR LARGE NO_X SOURCES

EQUIPMENT TYPE : KILNS AND CALCINERS

EQUIPMENT	MEASURED VARIABLES
Kilns and calciners	1. Fuel flow rate or exhaust flow rate (for sources with stack flow monitors); 2. Production rate (for sources permitted with emission rates corresponding to the measured variable);
Kilns and calciners with low NO_x burners	All variables identified for kilns and calciners.
Kilns and calciners with combustion modifications	All variables identified for kilns and calciners.
Kilns and calciners with FGR	All variables identified for kilns and calciners; AND 3. Flue gas recirculation rate.
Kilns and calciners with SCR	All variables identified for kilns and calciners; AND 3. Ammonia injection rate;
Kilns and calciners with SNCR	All variables identified for kilns and calciners; AND 3. Ammonia (or urea) injection rate;
Kilns and calciners with NSCR	All variables identified for kilns and calciners; AND 3. Natural gas (or other HC) injection rate.

EQUIPMENT TYPE : SULFURIC ACID PRODUCTION PLANTS

EQUIPMENT	MEASURED VARIABLES
Sulfuric acid plants	1. Fuel flow rate or exhaust flow rate (for sources with stack flow monitors); 2. Production rate (for sources permitted with emission rates corresponding to the measured variable);

Table 3-B

REPORTED VARIABLES FOR ALL LARGE NO_x SOURCES

EQUIPMENT	REPORTED VARIABLES
All large NO_x sources	1. Total Monthly mass emissions from each source;

Table 3-C

RULE-SPECIFIC NOx CONCENTRATION LIMITS AND EMISSION FACTORS

BASIC EQUIPMENT	RULE	CATEGORY	CONCENTRATION NOx LIMIT
Heaters,	1109	> 40 mmBtu/hr in petroleum refineries	24 ppmv @3 % O_2, dry*
Boilers, Steam	1146	≥ 5 mmBtu/hr and < 40 mmBtu/hr	40 ppmv @3 % O_2, dry
Generators	1146.1	≥ 40 mmBtu/hr	30 ppmv @3 % O_2, dry
		≥ 2 mmBtu/hr and < 5 mmBtu/hr	30 ppmv @3 % O_2, dry
Internal Combustion	1110.1	Rich Burn Lean Burn	90 ppmv @15% O_2, dry 150 ppmv @15% O_2, dry
Engines	1110.2	> 50 bhp subject to Rule 1110.2(c)(2)(A)	36 ppm @ 15% O_2, dry
		> 100 bhp portable subject to Rule 1110.2(c)(2)(A)	36 ppm @ 15% O_2, dry
		> 500 bhp subject to Rule 1110.2(c)(2)(B)	36 ppm @ 15% O_2, dry Reference limit
		50-500 bhp subject to Rule 1110.2(c)(2)(B)	45 ppm @ 15% O_2, dry Reference limit
Nitric Acid Production	1159	All Sizes	450 ppmv
Turbines	1134	≥ 0.3 MW and < 2.9 MW Peaking Units and Emergency Standby Equipment	Emission factor or concentration limit determined as described in R. 1134(c)(1)

*** Converted from Rule limit, which is 0.03 lb/mmBtu.**

Table 3-D

EMISSION FEE BILLING NOx FACTORS

BASIC EQUIPMENT	TYPE OF FUEL	EMISSION FACTOR	HIGHER HEATING VALUE OF FUEL
Boilers,	Natural Gas	130 lb/mmscf	1050 mmBtu/mmscf
Ovens,	Refinery Gas	161 lb/mmscf	1150 mmBtu/mmscf
Heaters,	LPG, Propane, Butane	12.8 lb/mgal	94 mmBtu/mgal
Furnaces,	Diesel Light Dist. (0.05% S)	19 lb/mgal	137 mmBtu/mgal
Kilns,	Fuel Oil (0.1% S)	20 lb/mgal	150 mmBtu/mgal
Calciners,	Fuel Oil (0.25% S)	60 lb/mgal	150 mmBtu/mgal
Dryers	Fuel Oil (0.5% S)	55 lb/mgal	150 mmBtu/mgal
Internal	Natural Gas	3400 lb/mmscf	1050 mmBtu/mmscf
Combustion	LPG, Propane, Butane	139 lb/mgal	94 mmBtu/mgal
Engines	Gasoline	102 lb/mgal	130 mmBtu/mgal
	Diesel Oil	469 lb/mgal	137 mmBtu/mgal
Gas Turbines	Natural Gas	413 lb/mmscf	1050 mmBtu/mmscf
	Diesel Oil	67.8 lb/mgal	137 mmBtu/mgal

Table 3-E

UNREGULATED DEFAULT NOx CONTROL EFFICIENCIES

BASIC EQUIPMENT	FUEL	CONTROL EQUIPMENT	EFFICIENCY
Boilers, Ovens, Heaters, Furnaces	Gas Fired	Selective Catalytic Reduction (SCR)	90
		Thermal DeNOx (SNCR)	40
		Low NOx Burner	35
		Flue Gas Recirculation (FGR)	38
	Oil Fired	Wet Scrubber	70
		Selective Catalytic Reduction (SCR)	80
		Thermal DeNOx (SNCR)	40
		Low NOx Burner	25
	(Distillate)	Flue Gas Recirculation (FGR)	58
	(Residual)	Flue Gas Recirculation (FGR)	15
		None	0
Internal Combustion Engines	Gas Fired	Combustion Modification	55
	(Lean Burn)	Selective Catalytic Reduction (SCR)	68
	(Rich Burn)	Non Select. Catalytic Reduction (NSCR)	86
		Injection Timing Retard 4 Degree	15
	Oil Fired	Injection Timing Retard 4 Degree	20
	(Diesel)	Selective Catalytic Reduction (SCR)	80
	(Diesel)	Injection Timing Retard 2 Degree	18
	(Diesel)	Injection Timing Retard 4 Degree& Turbocharger & Aftercooler	40
		None	0
Turbines	Gas Fired	Water or Steam Injection	37
		SCR and Steam Injection	70
		SCR and Water Injection	60
	Oil Fired		
	(Diesel)	Water or Steam Injection	40
	(Distillate)	Water or Steam Injection	30
		None	0

Table 3-F

STANDARD OXYGEN CONCENTRATIONS

BASIC EQUIPMENT	FUEL	CONTROL EQUIPMENT	% O2, DRY
Boilers, Ovens, Heaters, Furnaces	Gas Fired	Selective Catalytic Reduction (SCR)	3
		Thermal DeNOx (SNCR)	3
		Low NOx Burner	3
		Flue Gas Recirculation (FGR)	3
	Oil Fired	Wet Scrubber	3
		Selective Catalytic Reduction (SCR)	3
		Thermal DeNOx (SNCR)	3
		Low NOx Burner	3
	(Distillate)	Flue Gas Recirculation (FGR)	3
	(Residual)	Flue Gas Recirculation (FGR)	3
Internal Combustion Engines	Gas Fired	Combustion Modification	15 in every category
	(Lean Burn)	Selective Catalytic Reduction (SCR)	
	(Rich Burn)	Non Select. Catalytic Reduction (NSCR)	
		Injection Timing Retard 4 Degree	
	Oil Fired	Injection Timing Retard 4 Degree	
	(Diesel)	Selective Catalytic Reduction (SCR)	
	(Diesel)	Injection Timing Retard 2 Degree	
	(Diesel)	Injection Timing Retard 4 Degree & Turbocharger & Aftercooler	
Turbines	Gas Fired	Water or Steam Injection	15
		SCR and Steam Injection	15
		SCR and Water Injection	15
	Oil Fired		
	(Diesel)	Water or Steam Injection	15
	(Distillate)	Water or Steam Injection	15

3/17/17

SOUTH COAST AIR QUALITY MANAGEMENT DISCTRICT

RULE 2012 PROTOCOL
CHAPTER 4

PROCESS UNITS - PERIODIC REPORTING AND RULE 219 EQUIPMENT

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CHAPTER 4 - PROCESS UNITS PERIODIC REPORTING AND RULE 219 EQUIPMENT

Process units are one or more pieces of equipment which are listed in Table 1-C. The process units emissions are reported quarterly as shown in Table 4-A and based primarily on fuel consumption or operating time in conjunction with an emission factor. The requirements and procedures for an emission factor and election conditions for an alternative emission factor or concentration limit shall apply to process units. For equipment designated as exempt from permit in Rule 219 emissions shall be determined according to the methodology specified in this Chapter 4, subdivision F.

Process units and equipment exempt from permit as designated in Rule 219 may share fuel meters if each equipment has the same emission factor. This chapter also includes the equations describing the methods used to calculate NO_X process unit emissions and the reporting procedures. The interim reporting period does not apply to process units since existing fuel metering equipment or timers shall be used starting January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

A. MONITORING, REPORTING, AND RECORDKEEPING REQUIREMENTS

1. The category-specific starting emission factor found in Table 1 of Rule 2002 - Allocations for Oxides of Nitrogen (NO_X) and Sulfur (SO_X) shall be used for quantifying quarterly mass emissions for a NO_X process unit.

2. The Facility Permit holder of a process unit may request a category-specific emission rate that is reliable, accurate, and representative for purposes of calculating NO_X emissions. The emission rate shall be determined based on the source testing protocol specified in Chapter 5. The Facility Permit holder of a process unit may apply for a concentration limit for purposes of calculating NO_X emissions.

3. The Facility Permit holder of a process unit shall calculate the mass emissions according to the methodology specified in Paragraph 4.B.2. (totalizing fuel meters) or 4.B.3.a. (timers).

4. The Facility Permit holder of each NO_X Process Unit shall use a totalizing fuel meter or timer as applicable, as specified in the Facility Permit for each NO_X process unit to measure and report the variables listed in Tables 4-A and 4-B, respectively, for each NO_X process unit.

5. Fuel flow measuring devices used for obtaining stack flow in conjunction with F-factors shall be tested, when required, as installed for relative accuracy using reference methods to determine stack flow.

   a. The relative accuracy of the fuel flow meter must be determined using District reference Methods 1-4 and a three-run relative accuracy audit (RAA) at normal operating load. The accuracy of the fuel flow measuring system must be determined using the following equation:

$$A = (C_m - C_a)/C_a \times 100\% \qquad \text{(Eq. 15a)}$$

where:

A = accuracy of the fuel flow meter (%)

C_m = average flow rate response (scfh)

C_a = average reference method flow rate (scfh)

The value of fuel flow meter accuracy, as defined in Eq. 15a, shall be less than or equal to 15%.

b. Other acceptable alternatives to the above procedures used to determine the relative accuracy of the facility fuel flow meter or stack flow meter are listed under Chapter 3, Subdivision H.

6. Fuel meters and/or timers have to be non-resettable and tamper-proof. They have to have seals installed by the meter/timer manufacturer to prove the integrity of the measuring device.

Meters which are unsealed for maintenance or repairs shall be resealed by an authorized manufacturers representative.

7. The Facility Permit holder of each NO_x process unit shall monitor, report, and maintain the following records on a quarterly basis:

a. Type and quantity of fuel burned, in units of millions of standard cubic feet per quarter (mmscf per quarter) for gaseous fuels or thousand gallons per quarter (mgal per quarter) for liquid fuels, expressed to at least three significant figures; or

b. Total hours of operation; and

c. Production/Processing/Feed rate.

8. The Facility Permit holder of each NO_x process unit shall also provide any other data necessary for calculating the emission rates of nitrogen oxides as determined by the Executive Officer.

B. EMISSION CALCULATION FOR REPORTING DATA

1. Quarterly Mass Emissions for Interim Periods

Pursuant to Rule 2012 (f) (1), between January 1, 1994 and December 31, 1994 for Cycle 1 facilities, and between July 1, 1994 and June 30, 1995 for Cycle 2 facilities, the monthly emission of each process unit shall be calculated and recorded according to:

$$E_{ip} = \sum_{j=1}^{r} d_j \quad \text{x} \quad EF_{sj} \qquad \text{(Eq.22)}$$

where:

E_{ip} = The quarterly mass emission of nitrogen oxides for interim period (lb/quarter).

d_j = The quarterly fuel usage for each type of fuel recorded as mmscf/quarter or mgal/quarter).

EF_{sj} = The starting emission factor used to calculate unit emissions in the initial allocation, as specified in Table 1 of Rule 2002 - Allocations for Oxides of Nitrogen (NO_X) and Sulfur (SO_X) (lb/mmscf, lb/mgal).

r = The number of different types of fuel consumed per quarter.

j = Each type of fuel.0

Example calculation: Boiler burning natural gas, rated 6 mmBtu/hr, in compliance with Rule 1146 starting year 1994 Emission factor = 49.18 lb/mmscf Quarterly fuel usage = 1.1 mmscf per quarter E_{ip} = (49.18) x (1.1) = 54.1 lb/quarter Applicable emission factor is also found in Volume II - Supporting Documentation, Appendix II-F - Methodology for NO_x and SO_x Starting and Ending Allocation Factors, Table 2-4 - Startpoint 1994 Emission Factors for Nitrogen Oxides.

2. Totalizing Fuel Meter-Based Emission Calculation

The Facility permit holder shall use an emission factor shown in Table 1 of Rule 2002 or in Table 3-D or an approved equipment-specific or category-specific emission rate for each affected NO_x Process Unit to calculate the quarterly emissions according to:

$$E_k = \sum_{j=1}^{r} d_j \times EF_j \qquad \text{(Eq.23)}$$

or

$$E_k = \sum_{j=1}^{r} d_j \times V_j \times ER_j \qquad \text{(Eq.24)}$$

where:

E_k = The quarterly emissions of nitrogen oxides (lb/quarter).

d_j = The quarterly fuel usage for each type of fuel recorded by the fuel totalizer (mmscf/quarter or mgal/quarter)

EF_j= The emission factor specified in Table 1 of Rule 2002 - Allocations for Oxides of Nitrogen (NO_X) and Sulfur (SO_X) or specified in Table 3-D (lb/mmscf, lb/mgal). The emission factor found in Table 1 of Rule 2002 may or may not include the appropriate control efficiency.

V_j = The higher heating value of each type of fuel (mmBtu/mmscf or mmBtu/mgal) determined by the Facility Permit holder or assigned from Table 3-D.

ER_j = The equipment-specific or category-specific emission rate; fuel-specific emission rate requested by the Facility Permit holder (lb/mmBtu).

r = The number of different types of fuel consumed per month.

3. Timer-Based Emission Calculations

a. If the NO_x process unit is equipped with a timer, the quarterly fuel usage shall be quantified according to Eq. 25, 26 27, and 28 and the quarterly emissions for each affected NO_x process unit shall be calculated according to Eq. 23 and 24.

If the NO_x process unit does not measure fuel with a totalizing fuel meter, the quarterly fuel consumption for each affected equipment shall be quantified according to:

$$d = d_{pu} \times (H/H_{pu}) \qquad \text{(Eq.25)}$$

where:

d = The quarterly fuel consumption of an affected NO_x process unit without a dedicated fuel meter (mmscf/quarter or mgal/quarter).

d_{pu} = The quarterly fuel consumption of all NO_x process units at the facility (mmscf/quarter or mgal/quarter).

H = The quarterly heat input of an affected equipment without a dedicated fuel meter (mmBtu/quarter).

H_{pu} = The quarterly heat input of all NO_x process units at the facility (mmBtu/quarter).

Example Calculation:		
d_{pu}	=	1,587 mmscf/quarter
H	=	5,400 mmBtu/quarter
H_{pu}	=	27,000 mmBtu/quarter
d	=	d_{pu} x (H/H_{pu})
d	=	1,587 mmscf/qtr x (5,400 mmBtu/qtr ÷27,000 mmBtu/qtr)
d	=	317.4 mmscf/qtr

The quarterly fuel usage for all the NO_x process units at the facility (d_{pu}) shall be calculated according to:

$$d_{pu} = d_{fac} - (d_{large} + d_{major}) \qquad \text{(Eq.26)}$$

where:

d_{fac} = The quarterly fuel usage of all major and large sources and NO_x process units at the facility (mmscf/quarter or mgal/quarter).

d_{major} = The quarterly fuel usage of all major NO_x sources at the facility (mmscf/quarter or mgal/quarter).

d_{large} = The quarterly fuel usage of all large NO_x sources at the facility (mmscf/quarter or mgal/quarter).

Example Calculation:		
d_{fac}	=	174 mmscf/quarter
d_{major}	=	126 mmscf/quarter
d_{large}	=	30 mmscf/quarter
d_{pu}	=	$d_{fac} - (d_{large} + d_{major})$
d_{pu}	=	174 - (126 + 30)
d_{pu}	=	18 mmscf/quarter

The quarterly heat input of all the NO_x process units at the facility (H_{pu}) shall be calculated according to:

$$H_{pu} = \sum_{i=1}^{n} (R_i \times T_i) \qquad \text{(Eq.27)}$$

where:

R_i = The maximum rated fuel capacity of a NO_x process unit (mmBtu/hr).

T_i = The quarterly accumulated operation hours for a NO_x process unit (hrs/quarter).

n = The total number of NO_x process units at the facility.

Example Calculation:

R_1 = 3.5 mmBtu/hr
R_2 = 2.7 mmBtu/hr
T_1 = 480 hr/quarter
T_2 = 120 hr/quarter

$$H_{pu} = \sum_{i=1}^{2} (R_i \times T_i)$$

$$H_{pu} = (3.5 \times 480) + (2.7 \times 120)$$
$$H_{pu} = 2004 \text{ mmBtu/quarter}$$

The maximum rated heat input capacity of all NO_x process units shall be in units of mmBtu/hr. Since internal combustion engines are usually rated in units of brake horse power, the maximum rated heat input capacity of an engine shall be computed as follows:

$$R = 0.002545 \times bhp / eff \qquad \text{(Eq.28)}$$

where:

R = The maximum rated heat input capacity

eff = The manufacturer's rated efficiency @LHV x (LHV/HHV)

= 0.25, if not provided by the operator

bhp = The manufacturer's rated shaft output in brake horse power

Example Calculation:

eff = 0.25
bhp = 75 bhp
R = 0.002545 x bhp / eff
R = 0.002545 x 75/.25
R = 0.7635 mmBtu/hr

If gas turbines are rated in kilowatts, the rating shall be converted to mmBtu/hr by applying the manufacturer's heat rate (in mmBtu/kw-hr). If the manufacturer's heat rate is not available, a default value of 15,000 Btu/kw-hr shall be used.

Example Calculation:

Quarterly natural gas fuel usage for an ICE with maximum rated bhp of 90 bhp, 0.25 eff and a boiler rated at 4 mmBtu/hr is being served by one fuel meter reading 10.5 mmscf. The compliance emission rate of both ICE and boiler is 0.3 lb/mmBtu.

ICE = 90 bhp   Boiler= 4 mmBtu/hr
Fuel meter reading = d_{pu} = 10.5 mmscf

I.C.E.
R = 0.002545 x 90/.25 = 0.916 mmBtu/hr
t = 3 hr/day x 7 days/wk. x 4 wk./mo. x 3 mo/qtr = 252 hr/qtr
H_{ice} = R x t = 0.916 x 252 = 230.8 mmBtu/ quarter

Boiler
H_{boiler} = 4 mmBtu/hr x 24 hr./day x 7 day/wk. x 4 wk./mo. x 3 mo/qtr
H_{boiler} = 8064 mmBtu/quarter
H_{pu} = 230.8 + 8064 = 8294.8 mmBtu/qtr

d_{ice} = d_{pu} x (H_{ice}/H_{pu})
= 10.5 mmscf/qtr x (230.8/8294.8)
= .298 mmscf/qtr

d_{boiler} = d_{pu} x (H_{boiler}/H_{pu})
= 10.5 mmscf/qtr x (8064/8294.8)
= 10.2 mmscf/qtr

E_{ice} = d_{ice} x V x ER_c
= 1050 mmBtu/mmscf x 0.30 lb/mmBtu x .298 mmscf/qtr
= 93.87 lb/qtr
E_{boiler} = d_{boiler} x V x ER_c
= 10.2 mmscf/qtr x 1050 mmBtu/mmscf x 0.3 lb/mmBtu
= 3213 lb/qtr

E = E_{ice} + E_{boiler} = 93.87 + 3213 lb/qtr = 3307 lb/qtr

4. Concentration Limit based Emissions Calculations

When the Facility Permit holder elects to use the concentration limit, the quarterly mass emission shall be calculated and recorded according to one of the following equations:

a. Use the F-factor approach for oxygen except in cases where enriched oxygen is used, non-fuel sources of carbon dioxide are present (e.g., lime kilns and calciners), or the oxygen content of the stack gas is 19 percent or greater. Process units that are permitted to demonstrate compliance using the procedures in Rule 2012, Appendix A, Chapter 5, Subdivision H shall use the following equation to calculate and record nitrogen oxides mass emission rate even if the oxygen stack gas is 19 percent or greater. The following equation shall be used to calculate and record nitrogen oxides mass emission rate:

$$E_k = PPMV_{O2} \quad [20.9/(20.9 - b)] \times 1.195 \times 10^{-7} \times \sum_{j=1}^{R} (F_{dj} \times d_j \times V_j)$$

(Eq.28a)

where:

E_k	=	The quarterly mass emission of nitrogen oxides (lb/quarter).
$PPMV_{O2}$	=	The RECLAIM concentration limit as listed in the Facility Permit. (ppmv) and based on standardized oxygen concentration in the exhaust stream.
b	=	The standard concentrations of oxygen as listed in the Facility Permit or as found in Table 3-F. (%).
r	=	The number of different types of fuel.
j	=	Each type of fuel.
F_{dj}	=	The oxygen-based dry F factor for oxygen for each type of fuel, the ratio of the dry gas volume of the products of combustion to the heat content of the fuel (dscf/mmBtu) specified in 40 CFR Part 60, Appendix A, Method 19.
d_j	=	The quarterly fuel usage for each type of fuel recorded by the fuel totalizer (mmscf per quarter or mgal per quarter).
V_j	=	The higher heating value of the fuel for each type of fuel found in Table 3-D (mmBtu/mmscf or mmBtu/mgal) or determined by a continuous analyzer.

The product (d_j x V_j) shall have units of mmBtu per quarter (mmBtu/quarter).

For non-standard fuels that are not listed in 40 CFR Part 60, Appendix A, Method 19, a constant F-factor and heating value may be used if the Facility Permit holder demonstrates to the Executive Officer that the natural gas, fuel oil, or other fuels have stable F-factors and gross heating values. A stable F-factor or gross heating value is defined as not varying by more than + or - 2.5% from the proposed constant value. For the fuels listed in 40 CFR 60, Appendix A, Method 19, Table 19-1, the F-factors are assumed to be stable at the value cited in Table 19-1. Any F-factor cited in Regulation XX shall supersede the F-factor in Table 19-1. For fuels not listed in the citations above, but which the Facility Permit holder demonstrates that the source-specific F-factor meets the same stability criteria, periodic reporting of F-factor may be accepted and the adequacy of the frequency of analyses shall be demonstrated by the Facility Permit operator such that the probability that any given analysis will differ from the previous analysis by more than 5% (relative to the previous analysis) or less than 5%. Analysis records shall be maintained, including all charts and laboratory notes.

For non-standard fuels that are not listed in 40 CFR Part 60, Appendix A, Method 19 and do not satisfy the criteria for constant F-factor and heating value, the fuels must be analyzed on a continuous basis using gas chromatographs or other continuous technique that is approved by the Executive Officer. The continuous technique employed shall be capable of providing at a minimum a reading every fifteen-minute period.

b. If the F-factor approach for oxygen cannot be used, use the F-factor approach for carbon dioxide as specified in 40 CFR Part 60, Appendix A, Method 19, except in cases where the carbon dioxide concentration is less than one volume percent dry, non-fuel sources of carbon dioxide are present (e.g., lime kilns and calciners), or non-metered sources of fuel are present (e.g., afterburners). The following equation shall be used to calculate and record nitrogen oxides mass emission rate:

$$E_k = PPMV_{CO2} \times (100/\%CO_2) \times 1.195 \times 10^{-7} \times \sum_{j=1}^{r} (F_{cj} \times d_j \times V_j)$$

(Eq.28b)

Where:

E_k	=	The quarterly mass emission of nitrogen oxides (lb/quarter).
$PPMV_{CO2}$	=	The RECLAIM concentration limit as listed in the Facility Permit (ppmv) and based on standardized carbon dioxide concentration in the exhaust stream.
$\%CO_2$	=	The standard concentrations of stack gas carbon dioxide as listed in the Facility Permit.
r	=	The number of different types of fuel.
j	=	Each type of fuel.
F_{cj}	=	The carbon dioxide-based dry F factor for carbon dioxide for each type of fuel, the ratio of the dry gas volume of the products of combustion to the

heat content of the fuel (dscf/mmBtu) specified in 40 CFR Part 60, Appendix A, Method 19.

d_j = The quarterly fuel usage for each type of fuel recorded by the fuel totalizer (mmscf per quarter or mgal per quarter).

V_j = The higher heating value of the fuel for each type of fuel found in Table 3-D (mmBtu/mmscf or mmBtu/mgal) or determined by a continuous analyzer.

For non-standard fuels that are not listed in 40 CFR Part 60, Appendix A, Method 19, a constant F-factor and heating value may be used if the Facility Permit holder demonstrates to the Executive Officer that the natural gas, fuel oil, or other fuels have stable F-factors and gross heating values. A stable F-factor or gross heating value is defined as not varying by more than + or - 2.5% from the proposed constant value. For the fuels listed in 40 CFR 60, Appendix A, Method 19, Table 19-1, the F-factors are assumed to be stable at the value cited in Table 19-1. Any F-factor cited in Regulation XX shall supersede the F-factor in Table 19-1. For fuels not listed in the citations above, but which the Facility Permit holder demonstrates that the source-specific F-factor meets the same stability criteria, periodic reporting of F-factor may be accepted and the adequacy of the frequency of analyses shall be demonstrated by the Facility Permit operator such that the probability that any given analysis will differ from the previous analysis by more than 5% (relative to the previous analysis) or less than 5%. Analysis records shall be maintained, including all charts and laboratory notes.

For non-standard fuels that are not listed in 40 CFR Part 60, Appendix A, Method 19 and do not satisfy the criteria for constant F-factor and heating value, the fuels must be analyzed on a continuous basis using gas chromatographs or other continuous technique that is approved by the Executive Officer. The continuous technique employed shall be capable of providing at a minimum a reading every fifteen-minute period.

c. If the F-factor approach for carbon dioxide cannot be used, the nitrogen oxides mass emission rate shall be determined based on actual monthly stack flow rate from a continuous stack flow monitor and concentration limit at stack conditions as listed in the Facility Permit. The mass emission rate shall be determined by the following equation:

$$E_k = PPMV_{ST} \times 1.195 \times 10^{-7} \times \sum_{j=1}^{N} F_j \qquad \text{(Eq. 28c)}$$

where:

E_k = The quarterly mass emission of nitrogen oxides (lb/quarter).

$PPMV_{ST}$ = The concentration limit at stack condition as listed in the Facility Permit (ppmv).

F_j = Total quarterly stack flow rate (scf/quarter) of stack j.

N = Number of exhaust stacks.

For systems that record hourly exhaust flow rate data, the total quarterly stack flow rate shall be determined by the following equation:

$$F_j = \sum_{i=1}^{M} H_{ij} \qquad \text{(Eq. 28d)}$$

F_j = Total quarterly stack flow rate (scf/quarter) of stack j.

H_{ij} = Hourly stack flow rate (scf/hour) of stack j.

M = Total number of hours for the quarter.

Whenever valid stack flow rate data is not obtained for an hour, the Facility Permit holder shall calculate substitute data using the missing data procedures applicable to flow as set forth in Appendix A, Chapter 3, Subdivision K, Paragraph 2.

C. TOTAL QUARTERLY EMISSIONS CALCULATION FOR ALL NO_x PROCESS UNITS AT THE FACILITY

The quarterly NO_x emissions of all NO_x process units at the facility shall be quantified according to:

$$E = \sum_{i=1}^{n} E_i \qquad \text{(Eq.29)}$$

$$E_i = \sum_{j=1}^{m} E_j \qquad \text{(Eq. 30)}$$

where:

E = The total quarterly emissions for all NO_x process units

E_i = The quarterly emission of each NO_x process unit (lb/quarter)

E_j = The quarterly emission of each NO_x process unit per type of fuel (lb/quarter)

i = Each type of affected NO_x process unit

j = Each type of fuel

m = The total number of fuels consumed for each affected NO_x process unit per quarter

n = The total number of NO_x process units at the facility.

Example Calculation:

$$E_1 = 163.8 \text{ lb/quarter}$$
$$E_2 = 78 \text{ lb/quarter}$$
$$E_3 = 120 \text{ lb/quarter}$$
$$E = \sum_{i=1}^{n} E_i = 163.8 + 78 + 120$$
$$E = 361.8 \text{ lb/quarter}$$

D. REPORTING PROCEDURES

1. The emissions data in any facility with an RTU shall be reported to Central Station Computer at the end of any quarter and the data shall be computed to determine the quarterly total emissions for each source using Equations 22 through 28 as appropriate.

2. The total fuel usage data for all NO_x process units in any facility without an RTU shall be recorded in a format approved by the Executive Officer and submitted to the District as part of the Quarterly Certified Report required by Rule 2004.

3. The Facility Permit holder of NO_x process units shall maintain daily records of operation hours or quarterly usage rate for each NO_x process unit.

4. Any changes made in type of fuel used and rated capacity for each source shall be recorded by the Facility Permit holder.

5. The Facility Permit holder of any NO_x process unit that opts to monitor at the large source monitoring level shall meet the requirements set forth in "Chapter 3 Large Sources - Continuous Process Monitoring System (CPMS)".

E. FUEL METER SHARING

1. A single totalizing fuel meter shall be allowed to measure the cumulative fuel usage for more than one equipment provided that each equipment elects for the same emission rate or emission factor as specified in the Facility Permit and that any equipment in a process unit does not use the annual heat input in order to be categorized from a large source to a process unit.

2. One or more equipment in a process NO_x unit shall be allowed to share the fuel totalizing meter with the equipment in a process NO_x unit provided that each equipment elects for the same emission rate or emission factor as specified in the Facility Permit.

3. Fuel meter sharing for the interim period shall be allowed for those equipment in a process unit with the same emission rate or emission factor.

F. RULE 219 EQUIPMENT

1. Emission Determination And Reporting Requirements

a. The Facility Permit holder shall determine the emissions for one or more equipment exempt under Rule 219 and report the emissions on a quarterly basis as part of the Quarterly Certified Emissions Report Certification of Emissions required by Rule 2004. The Facility Permit holder shall be allowed to use the existing fuel totalizer, the monthly fuel billing statement, or any other equivalent methodology to quantify their fuel usage for a quarterly period.

b. Quarterly reporting periods shall start on January 1, 1994 for Cycle 1 Facilities and July 1, 1994 for Cycle 2 facilities.

c. The Facility Permit holder of each equipment shall maintain the quarterly fuel usage data for all equipment exempt under Rule 219 for three years. Such data shall be made available to District staff upon request.

d. The fuel usage for equipment exempt under Rule 219 may be used in conjunction with fuel usage for process units provided that they have the same emission factor.

2. Emission Calculations

The Facility Permit holder shall determine NO_x emissions for equipment exempt under Rule 219 as follows:

$$E_{219} = \sum_{i=1}^{n} EFR_i \times d_i \qquad \text{(Eq. 31)}$$

where:

E_{219} = The total emissions for equipment exempt under Rule 219 quantified over a quarterly period (lb/quarter).

EFR_i = The equipment-specific or category-specific emission factor for each equipment exempt under Rule 219 equipment. The emission factor can be found in Table 3-D (lb/mmscf or lb/mgal). Alternatively, for an equipment certified by US EPA, CARB, or SCAQMD as meeting a certain emission level, an appropriate emission factor equivalent to the certified emission level may be used provided the facility complies with the source test or maintenance requirements specified in paragraph 4.

d_i = The equipment-specific or category-specific fuel usage (mmscf/quarter or mgal/quarter).

n = The number of equipment exempt under Rule 219.

3. Missing Data Periods

The Facility Permit holder shall determine NOx emissions for equipment exempt under Rule 219 using the substitute data procedures specified in Subdivision G of this Chapter for any quarter for which the Facility Permit holder did not obtain and record valid fuel consumption data as required by Subdivision F, Paragraphs 1 and 2 of this Chapter.

4. Source Testing and Maintenance

Each equipment exempt under Rule 219 with NO_x emissions determined using an alternative emission factor based on a US EPA, CARB, or SCAQMD certified emission level shall either be periodically source tested pursuant to F.4.a. or maintained pursuant to F.4 b.

a. Source Testing

i. Conduct periodic source tests to verify that emissions are less than or equal to the US EPA, CARB, or SCAQMD certified emission level. Each such source test shall comply with the provisions of Chapter 5 D.1. and D.2.

ii. Each device subject to this source testing requirement shall be tested on the same schedule as specified in Table 5-B for Process Unit with Concentration Limit, except in cases where a facility has multiple devices subject to this source testing requirement, all with the same US EPA, CARB, or SCAQMD certification. In such cases the facility operator may conduct the source testing of at least half of the devices with the same certification each five-year period provided each device is source tested at least once every two successive five-year periods.

iii. If a source test determines that an equipment exempt under Rule 219 with NO_x emissions quantification using an emission factor equivalent to the US EPA, CARB, or SCAQMD certified emission level has emissions greater than the emission factor used for emission quantification, emissions from that source and all other sources engaged in meter sharing with that source pursuant to subdivision E of this chapter shall quantify emissions using the appropriate equipment-specific or category-specific emission factor in Table 3-D from the start of the quarter in which the source test was conducted through the end of the quarter in which a subsequent source test demonstrates that the source's emissions are less than or equal to the emission factor.

b. Maintenance

i. Conduct annual maintenance on the equipment to ensure emissions remain at or below the US EPA, CARB, or SCAQMD certified emission level. Promptly after completing such maintenance, verify that the emissions from each device subject to this maintenance requirement remain at or below the US EPA, CARB, or SCAQMD certified emission level with a portable NOx, CO, and oxygen analyzer according to the Combustion Gas Periodic Monitoring Protocol for the Periodic Monitoring of Nitrogen Oxides, Carbon Monoxide, and Oxygen from Combustion Sources Subject to South Coast Air Quality Management District Rules 1110.2, 1146, and 1146.1.

ii. If an annual maintenance emission check with a portable analyzer determines that an equipment exempt under Rule 219 with NO_x emissions quantification using an emission factor equivalent to the US EPA, CARB, or SCAQMD certified emission level has emissions greater than the emission factor used for emission quantification, emissions from that source and all other sources engaged in meter sharing with that source pursuant to subdivision E of this chapter shall quantify emissions using the appropriate equipment-specific or category-specific emission factor in Table 3-D from the start of the quarter in which the portable analyzer emission check was conducted through the end of the quarter in which a subsequent portable analyzer emission check demonstrates that the source's emissions are less than or equal to the emission factor.

c. Recordkeeping

Each facility that elects to comply with subdivision 2 by implementing the procedures specified in paragraph 4.a. or 4.b. shall keep records of all testing, maintenance, and verification conducted pursuant to those paragraphs for at least three years and make such records available to the Executive Officer upon request.

G. SUBSTITUTE DATA PROCEDURES

1. For each process unit or process units using a common fuel meter, elapsed time meter, or equivalent monitoring device, the Facility Permit holder shall provide substitute data as described below whenever a valid quarter of usage data has not been obtained and recorded. Alternative data, based on a back-up fuel meter, elapsed time meter, or equivalent monitoring device, is acceptable for substitution if the Facility Permit holder can demonstrate to the Executive Officer that the alternative system is fully operational during meter down time and within + or - 2% accuracy. The substitute data procedures are retroactively applicable from the adoption date of the RECLAIM program.

2. Whenever data from the process monitor is not available or not recorded for the affected equipment or when the equipment is not operated within the parameter range specified in the Facility Permit, the Facility Permit holder shall calculate substitute data for each quarter, when valid data has not been obtained, according to the following procedures.

   a. For a missing data period less than or equal to one quarter, substitute data shall be calculated using the process unit(s) average quarterly fuel usage for the previous four quarters. If four quarters of data are not available, substitute data shall be calculated as if the facility has no records.

   b. For a missing data period greater than one quarter, substitute data shall be calculated using the process unit(s) highest quarterly fuel usage data for the previous four quarters. If four quarters of data are not available, substitute data shall be calculated as if the facility has no records.

   c. If the facility has no records, substitute data shall be calculated using 100% uptime during the substitution period and the process unit(s) maximum rated capacity and uncontrolled emission factor for each quarter of missing data.

   d. For a process monitor which uses a gas chromatograph or equivalent continuous method to continuously determine the F-factor and higher heating value of the fuel (Rule 2012, Appendix A, Chapter 4, Subdivision B.4.a.i), the Facility Permit holder shall use the stack gas flow rate missing data substitution procedure for major sources (Rule 2011 or 2012, Appendix A, Chapter 2, Subdivision E.2).

TABLE 4-A

MEASURED VARIABLES FOR ALL NO_x PROCESS UNITS

EQUIPMENT	MEASURED VARIABLES
All NO_X process units	1. Fuel usage or exhaust flow rate (for sources with stack flow monitors) or processing/feed rate or operating time 2. Production rate (for sources permitted with emission rates corresponding to the measured variable);

TABLE 4-B

REPORTED VARIABLES FOR ALL NO_x PROCESS UNITS

EQUIPMENT	REPORTED VARIABLES
All NO_X process units	1. Quarterly mass emissions

RULE 2012 PROTOCOL- CHAPTER 5

LARGE SOURCES AND PROCESS UNITS - SOURCE TESTING

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CHAPTER 5 - LARGE SOURCES AND PROCESS UNITS - SOURCE TESTING

This chapter contains the source testing frequency requirements for large sources. Also included are the source testing methods and procedures necessary for a Facility Permit holder of a large NOx source or process unit to establish an alternative emission factor. The Facility Permit holder of a large source or process unit may use a statistically equivalent methodology upon approval by the Executive Officer. Statistically equivalent methodologies shall be submitted to the Federal Environmental Protection Agency as an amendment to the State Implementation Plan (SIP).

Large sources and process units differ in the methodology used to evaluate source test data and determine the validity of the results.

Every large NO_X source shall be source tested no later than December 31, 1996 for Cycle 1 facilities and June 30, 1997 for Cycle 2 facilities, and every three-year period thereafter. In lieu of submitting the first source test report, the Facility Permit holder may submit the results of a source test not more than three years old which meets the requirements of this Chapter. The Facility Permit holder of a large source or NO_X process unit shall substantiate the emission rate according to the requirements set forth in this chapter.

All required source tests for RECLAIM NOx sources and process units shall be performed by testing firms/laboratories who have received approval under the District's Laboratory Approval Program.

A. Test Methods

The Facility Permit holders of all RECLAIM NO_X sources, when required, shall source test each equipment using the following test methods and procedures referenced in the District Source Test Manual and 40 CFR Part 60, Appendix A:

1. Determinations and measurements prior to sampling:

    a. Method 1.1 - sample points, stacks greater than 12 in. diameter

    b. Method 1.2 - sample points, stacks less than 12 in. diameter

    c. Method 2.1 - flow rate, stacks greater than 12 in. diameter

    d. Method 2.2 - flow rate, direct measurement

    e. Method 2.3 - flow rate, stacks less than 12 in. diameter

    f. Method 4.1 - moisture

    g. EPA Method 19 - calculated flow

    h. Direct in-stack instrumental flow measuring device

2. Nitrogen oxides concentration:

   a. Method 100.1 - nitrogen oxides

   b. Method 7.1 - nitrogen oxides

3. Oxygen concentration:

   a. Method 3.1 - molecular weight and excess air

   b. Method 100.1 - oxygen

4. [Reserved for methodology to measure NO_X emissions from process units.]

B. Summary of Testing Requirements

The Facility Permit holder is required to source test all Super Compliant major NOx sources, all large NOx sources, and all NO_X process units which opt for a concentration limit or emission rate as follows:

1. Super Compliant Major NOx Sources

   Once a Super Compliant major NOx source has been approved, the Facility Permit holder shall source test the equipment once every two calendar quarters. The test shall include a single 60 minute NOx concentration test and a relative accuracy audit of the fuel measuring device. If four consecutive bi-quarterly tests all show compliance, the testing frequency may be reduced to once per year.

2. Large NOx Sources

   A large NOx source is required to determine emissions based on the concentration limit in the Facility Permit. The Facility permit holder also has the option to determine emissions based on an emission rate. All large NOx sources shall be source tested according to one of the following:

   a. If the large source is subject to a RECLAIM concentration limit, the Facility Permit holder is required to source test each large NOx source once every three-year period, as specified in Rule 2012(j)(2) to verify compliance with the concentration limit pursuant to Subdivision (D). This test shall include a single 60 minute NOx concentration test and a relative accuracy audit of the fuel measuring device. For sources that cannot be tested in accordance with Subdivision (D) due to high oxygen content and low carbon dioxide content in the exhaust stream, the Facility Permit holder may submit a permit application to request that the compliance verification test be conducted pursuant to Subdivision (H) if the Facility Permit holder demonstrates that the source can be tested in accordance with procedures in Subdivision (H).

b. If the Facility Permit holder opts for an equipment specific emission rate, they are required to determine an equipment specific emission rate pursuant to Subdivision (E). These requirements include source testing the equipment for NOx mass emissions for three 30 minute runs at four different loads that span its normal operating range. The resulting data is required to pass a statistical "t-test" to be considered valid. Once the equipment specific emission rate is determined to be valid, the Facility Permit holder is then required to test its equipment every three-year period to show that it is still in compliance with the equipment specific emission rate. This three-year test shall include testing the equipment for NOx mass emissions for one 30 minute run at each of the four original loads that span its normal operating range.

3. NOx Process Units

Emission factors are assigned to process units when the Facility Permit is issued. No source testing is required for a process unit, unless the Facility permit holder opts for either a concentration limit or an emission rate.

a. If the Facility Permit holder opts for a concentration limit, they are required to source test each process unit once every five-year period, as specified in Rule 2012(j)(4) to verify compliance with the concentration limit pursuant to Subdivision (D). This test includes a single 60 minute NOx concentration test and a relative accuracy audit of the fuel measuring device. For process units that cannot be tested in accordance with Subdivision (d) due to high oxygen content and low carbon dioxide content in the exhaust stream, the Facility Permit holder may submit a permit application to request that the compliance verification test be conducted pursuant to Subdivision (H) if the Facility Permit holder demonstrates that the source can be tested in accordance with procedures in Subdivision (H).

b. If the Facility Permit holder opts for an equipment specific emission rate, they are required to determine an equipment specific emission rate pursuant to Paragraph (F)(1). These requirements include source testing the equipment for NOx mass emissions for three 30 minute runs at four different loads that span its normal operating range. The resulting data is required to pass a statistical "t-test" to be considered valid. Once the equipment specific emission rate is determined to be valid, no further testing is required.

c. If the Facility Permit holder opts for a category specific emission rate, they are required to determine the category specific emission rate pursuant to Paragraph (F)(2). Once the category specific emission rate is determined to be valid, no further testing is required.

C. Testing frequency

The operator of all NO_X sources shall source test or tune-up their equipment according to the schedule in Table 5-B.

D. Concentration Limit

To verify compliance for a concentration limit for super compliant major NOx sources, large NOx sources, or process units, all of the following shall be met:

1. Submit a source testing plan to the District and receive written approval of the plan or follow a District standard source testing protocol;

2. Conduct the source test for a minimum of 60 minutes at a load within the normal operating range of the source which will represent the highest NOx concentration level;

3. Conduct a relative accuracy audit (RAA) for stack flow rate following the procedures in Appendix A, Chapter 3, Paragraph A(6) for super compliant major NOx sources and large NOx sources, and Appendix A, Chapter 4, Paragraph A(5) for process units; and

4. Perform these tests at the frequency specified in Table 5-B.

E. Guidelines for Testing to Establish an Equipment Specific Emission Rate for Large Sources

1. For large sources the Facility Permit holder may elect to establish an equipment specific emission rate that accurately represents the emissions from the source over the range of operation under which the testing was done. The equipment specific emission rate shall be used to determine compliance with the facility's annual emission cap.

2. The criterion for acceptability of the equipment specific emission rate shall be a 95% confidence interval that the tested emission rates will be within 20% of the equipment specific emission rate. If a single equipment specific emission rate does not meet this criterion over the entire range of operation, the District will allow up to three equipment specific emission rates to cover a "normal operating range", a "high operating rate and a

"low operating range," respectively. The "normal operating range" shall cover operations for at least 80% of the entire operating time. The equipment specific emission rate at the entire range or at respective low, normal, and high operating range shall be determined according to:

$$ER_c = (1/n) \sum_{i=1}^{n} ER_i \qquad \text{(Eq.32)}$$

$$S_{ER} = [\sum_{i=1}^{n} (ER_i - ER_c)^2/(n - 1)]^{1/2} \qquad \text{(Eq.33)}$$

$$CC = t_{0.975}\, S_{ER}/(n)^{1/2} \qquad \text{(Eq.34)}$$

$$C.I.\ (\%) = \frac{|CC|}{ER_c} \qquad \text{(Eq.35)}$$

where:

S_{ER} = The standard deviation (lb/mmBtu)

i = Each testing.

n = The number of testing data points to determine the equipment specific emission rate at entire range or low, normal, and high operating range, respectively

ER = The emission rate (lb/mmBtu) determined at each testing under each condition at the entire range or low, normal, and high operating range, respectively.

CC = The confidence coefficient

$t_{0.975}$ = The t value (one-tailed) determined from Table 5-A

ER_c = The equipment specific emission rate (lb/mmBtu) determined over an entire range, or determined at low, normal, and high operating range, respectively.

C.I. = The confidence interval with 95 % confidence level (%)

Table 5-A - Table of the Factor $t_{0.975}$ for Obtaining One-Tailed Confidence Interval for the Mean*

n*	$t_{0.975}$	n*	$t_{0.975}$	n*	$t_{0.975}$
6	2.571	9	2.306	12	2.201
7	2.447	10	2.262	13	2.179
8	2.365	11	2.228	14	2.160

* The values in this table are already corrected for n-1 degrees of freedom. Use n equal to the number of individual values. 40 CFR Part 60, App B, Spec. 1.

3. The Facility Permit holder shall identify the monitoring parameter(s) to establish the allowable operating range of process variables to be specified in the Facility Permit for the affected sources from Table 3-A in Chapter 3 for large sources. This list is not intended to be all inclusive and the Facility Permit holder may identify additional parameters not listed in Table 3-A. The test conditions are typically related to percent of load; however, the Facility Permit holder may propose any other monitoring parameters as deemed necessary and propose the operating range of these monitoring parameters to ensure that the equipment specific emission rate(s) and control efficiency continue to fall within the confidence criterion.

4. The Facility Permit holder shall conduct source tests to verify the amended equipment specific emission rate according to the methods identified in Chapter 5, Subdivision A, or statistically equivalent methodologies. The testing shall be done in three phases.

5. Phase I testing shall constitute "normal operating range" testing. From the "normal operating range" the equipment specific emission rate shall be calculated by using the tested emission rates. To determine a tested equipment specific emission rate the Facility Permit holder shall test at four conditions that span the "normal operating range". At each condition an emission rate shall be tested three times, but not consecutively. If there are two (or more) monitoring parameters the Facility Permit holder shall identify the primary parameter (i.e. having the greatest effect on emission rate variation) and secondary monitoring parameter(s), (i.e. having the least effect on emission rate variation). The Facility Permit holder shall test at four conditions that span the "normal operating range" of the primary monitoring parameter and at each primary monitoring parameter condition, test at least two secondary monitoring parameter test conditions that span the "normal range" of the secondary operating monitoring parameter(s). Each test shall be conducted for a period of at least 30 minutes. On this basis, the equipment specific emission rate and the 95% confidence interval shall be calculated. If the 95% confidence interval meets the 20% criterion, the unit shall be allowed to use this rate for

"normal operating range" upon the approval of the Executive Officer. If the criterion is not met the Facility Permit holder shall reduce the "normal operating range" and conduct any additional tests to provide the required data sets.

6. Phase II testing shall constitute "high operating range" testing. The Facility Permit holder shall test at two conditions that span the "high operating range". At each condition an emission rate shall be tested three times, but not consecutively. Multiple operating conditions shall be addressed in a similar manner as described for Phase I testing. The values from these tests shall be added to the data from "normal operating range" testing and a test equipment specific emission rate and test 95% confidence interval shall be generated. If the 95% confidence interval for the test equipment specific emission rate meets the 20% criterion, then the test equipment specific emission rate shall become the allowed rate for both the "normal and high" operating ranges. If the criterion is not met, then a "high operating range" equipment specific emission rate and 95% confidence interval shall be calculated from the data. If the 20% criterion is met then the facility shall use this as a "high operating range" equipment specific emission rate. If the 20% criterion is not met then tests at two additional conditions within the high range shall be conducted and the 20% criterion again applied to the "high operating range" data set only. If the 20% criterion is still not met, then the "high operating range" shall be reduced.

7. Phase III testing shall constitute "low operating range" testing. This Phase testing is carried out in the same manner as Phase II testing. If a single "normal/high operating range" equipment specific emission rate has been determined from Phase II testing, then all of the data for "normal and high" operating range testing shall be included. If not, then only data from the "normal operating range" testing shall be included to create the "test equipment specific emission rate". The same acceptance criteria apply as specified under Phase II testing.

8. If the equipment specific emission rate in each phase complies with the Confidence Interval, the Facility Permit holder may use up to three equipment specific emission rates, each representing a different phase, provided that load duration for each specified phase equipment specific emission rate is monitored and recorded at the facility.

Example calculation:

In order to establish the equipment specific emission rate, the Facility Permit holder selected four operating conditions over the entire operating range. The results are as follows:

	Data 1	Data 2	Data 3
Condition 1	0.15	0.20	0.50
Condition 2	0.30	0.24	1.00
Condition 3	0.40	0.20	0.50
Condition 4	0.50	0.40	0.30

The confidence interval calculations are as follows:

ERc = (0.15 + 0.20 + 0.50 + 0.30 + 0.24 + 1.00 + 0.40 + 0.20 + 0.50 + 0.50 + 0.40 + 0.30)/12 = 0.39083

SER = 0.219196 (according to Eq.32)

CC = (2.201) * 0.219196/(11)1/2 = 0.1454

C.I.(%) = 0.1454/0.39083 = 37.2 % > 20 %

The proposed data set failed the confidence interval test, therefore the Facility Permit holder shall select low, normal, or high range, whichever is representative of their typical operating range according to Paragraphs 6.A.5.c.d.e.f. or g.

F. Guidelines for Testing to Establish Emission Rate for process units

1. Equipment Specific Emission Rate (ESER)

a. For process units the Facility Permit holder shall comply with an equipment specific emission rate that accurately represents the emissions from the source or the unit over the range of operation under which the testing was done. The equipment specific emission rate shall be used to determine compliance with the facility's annual emission cap.

b. The equipment specific emission rate shall be calculated by using tested emission rates from a "normal operating range". The "normal operating range" shall cover operations for at least 80% of the entire operating time. The criterion for acceptability of these tested emission rates shall be an 95% confidence interval that the tested emission rates will be within 25% of the equipment specific emission rate. The equipment specific emission rate over the "normal operating range shall be determined according to:

$$ER_c = (1/n) \sum_{i=1}^{n} ER_i \qquad \text{(Eq.36)}$$

$$S_{ER} = \left[\sum_{i=1}^{n} (ER_i - ER_c)^2/(n-1)\right]^{1/2} \quad \text{(Eq.37)}$$

$$CC = t_{0.975}\, S_{ER}/(n)^{1/2} \quad \text{(Eq.38)}$$

$$C.I.\ (\%) = \frac{|CC|}{ER_c} \quad \text{(Eq.39)}$$

where:

S_{ER} = The standard deviation (lb/mmBtu).

i = Each testing.

n = The number of testing data points to determine the equipment specific emission rate at the "normal operating range".

ER = The emission rate (lb/mmBtu) determined at each testing under each condition at the "normal operating range".

CC = The confidence coefficient.

$t_{0.975}$ = The t value (one-tailed) determined from Table 5-A.

ER_c = The equipment specific emission rate (lb/mmBtu) determined over the entire "normal operating range".

C.I. = The confidence interval with 95 % confidence level (%).

c. The Facility Permit holder shall identify the source test parameter(s) to establish the boundaries of operating conditions for the affected sources from Table 4-A in Chapter 4 for process units. This list is not intended to be all inclusive and the Facility Permit holder may identify additional source test parameters not listed in Table 4-A. The test conditions are typically related to percent of load; however, the Facility Permit holder may propose any other source test parameters as deemed necessary and propose the operating range of these source test parameters to ensure that the equipment specific emission rate(s) continue to fall within the confidence criterion.

d. The Facility Permit holder shall conduct source tests to verify the amended equipment specific emission rate according to the methods identified in Chapter 5, Subdivision A, or statistically equivalent methodologies. The testing shall be done over the "normal operating range".

e. From the "normal operating range" the equipment specific emission rate shall be calculated by using the tested emission rates. To determine a tested emission rate, the Facility Permit holder shall test at four conditions that span the "normal operating range". At each condition an emission rate shall be tested three times, but not consecutively. If there are two (or more) source test parameters the Facility Permit holder shall identify the primary source test parameter (i.e. having the greatest effect on emission rate variation) and secondary source test parameter(s), (i.e. having the least effect on emission rate variation). The Facility Permit holder shall test at four conditions that span the "normal operating range" of the primary source test parameter and at each primary source test parameter condition, test at least two secondary source test parameter test conditions that span the "normal range" of the secondary operating source test parameter(s). Each test shall be conducted for a period of at least 30 minutes. On this basis, the equipment specific emission rate and the 95% confidence interval shall be calculated. If the 95% confidence interval meets the 25% criterion, the unit shall be allowed to use this equipment specific emission rate for "normal operating range" upon the approval of the Executive Officer. If the criterion is not met the Facility Permit holder shall reduce the "normal operating range" and conduct any additional tests to provide the required data sets.

2. Category Specific Emission Rate (CSER)

a. For process units, the Facility Permit holder has, in lieu of a concentration limit or equipment specific emission rate (ESER), the option to establish, in the Facility Permit, with a category specific emission rate (CSER). A CSER is an average of ESERs of a group of three or more process units which:

i are the same type of equipment, i.e. equipment within a narrow range of rating, same manufacturer, family of model, and emission characteristics;

ii perform the same functions or processes;

iii meet the statistical limits of Clause (F)(2)(b)(ii); and

iv are all located at a single RECLAIM facility.

A CSER must be approved by the Executive Officer and listed in the Facility Permit before it may be used to determine compliance with the facility's annual emission cap.

b. The CSER is determined by the following:

i. A minimum of three devices of the category must be tested, and ESERs established for each of the three devices each meeting the statistical test methods for ESER in Paragraph F(1).

ii. The three ESERs will then be averaged to determine the CSER. The aggregate 36 tests of the three devices must pass a statistical "f-test" at a 95% confidence level for the CSER to be considered valid.

iii. Once the CSER has been established, approved as valid, and listed on the facility permit it can then be used to report emissions from the subject devices.

iv. To add one or more devices to this CSER, the new devices must meet the criteria in Subparagraph (F)(2)(a) and the facility must source test the new devices for one 30 minute run at each of the four loads the CSER was established. The results shall then be subjected, with the previous 36 tests, to the statistical "f" test and must meet at a 95% confidence level to be considered valid and the CSER applicable to the new devices.

G. Equipment tune-up procedures

Follow the "Equipment Tuning Procedure" as specified in Attachment D.

H. Alternative Method for Demonstrating Compliance with Concentration Limit

For sources that cannot be tested in accordance with Subdivision (D) due to high oxygen content and low carbon dioxide content in the exhaust stream, the Facility Permit holder may demonstrate compliance with the concentration limit using the following procedures:

1. The Facility Permit holder shall submit an application requesting use of this alternative compliance demonstration method. This alternative method shall not be applicable unless the Facility Permit is re-issued to allow the use of this method.

2. This alternative method shall not be used unless the Facility Permit holder demonstrates to the satisfaction of the Executive Officer that the source meets all of the following requirements:

   a. The source cannot be tested in accordance to Subdivision D to demonstrate compliance due to high oxygen content and low carbon dioxide content in the exhaust from the source;

   b. The source can be tested using procedures under Paragraph H.3;

   c. The source only combusts one of the fuel types that is listed in Table 5-C;

   d. For sources with multiple points of emissions, each emission point from the source can be tested independently of other emission points to yield a single emission rate at each point; and

   e. The exhaust from the source contains no products of combustion other than those directly related to the combustion of fuels listed in Table 5-C.

3. The fuel meter shall be calibrated by a third party using procedures under Rule 2012, Appendix A, Chapter 3, Paragraph H.4, no more than 6 months prior to conducting the source test. If the source is served by a shared fuel meter, the source shall be tested when the other sources served by the same fuel meter are not consuming any fuel. The source shall be tested for a duration of 60 minutes using test methods and procedures referenced in the District Source Test Manual and 40 CFR Part 60, Appendix A to determine:

   a. Total mass of NOx emissions at each emission point;

   b. Total fuel consumed at each emission point; and

   c. Rate of emissions at each emission point in pounds per unit of fuel (e.g. pounds per million standard cubic feet for natural gas fired sources and pounds per 1000 gallons for fuel oil-fired sources).

4. Compliance with the concentration limit shall be demonstrated by comparing the tested emission rate (R_t) at each point of emission to the emission rate converted (R_c) from the Facility Permit concentration limit for the source, as expressed in the same units (e.g. lbs/mmscf or lbs/1000 gals), by using Eq. 41. In the event that at any emission point, the tested emission rate is greater than the converted emission rate, the source shall be deemed to be operating in excess of the permitted concentration limit in violation of Rule 2012 (f)(2)(A) or Rule 2012(e)(2)(E), whichever is applicable for the source. In such case, the source shall be subject to the

requirements of Rule 2004(g) and emissions from the source shall be determined using the higher tested emission rate until the day that the source is demonstrated to operate in compliance with the concentration limit as stated in the Facility Permit.

$$R_c = PPMV_{O2} \times [20.9/(20.9 - b)] \times 1.195 \times 10^{-7} \times F_d \times V \qquad \text{(Eq. 41)}$$

Where:

R_c	=	The emission rate converted from the Facility Permit concentration limit for the source.
$PPMV_{O2}$	=	The RECLAIM Concentration Limit as listed in the Facility Permit and based on standardized oxygen concentration in the exhaust stream.
b	=	The standard concentrations of oxygen (%) as listed in the Facility Permit or as found in Table 3-F if not listed in the Facility Permit
F_d	=	The dry F factor for oxygen for each type of fuel, the ratio of the dry gas volume of the products of combustion to the heat content of the fuel (dscf/mmBtu), as specified in Table 5-C or as determined during the same source test used to obtain the emission rate.
V	=	The higher heating value of the fuel for each type of fuel found in Table 5-C or as determined during the same source test used to obtain the emission rate.

Example:

Natural gas-fired Boiler permitted at 30 ppmv, 3% O_2 and vented to a single stack

Total mass of NOx based on source test = 21 lbs

Fuel consumed during the source test = 0.8 mmscf

F_d = 8710 dscf/mmBtu

V = 1050 mmBtu/mmscf

R_c = 30 ppmv x [20.9/(20.9 – 3)] x 1.195x 10^{-7}
x 8710 dscf/mmBtu x 1050 mmBtu/mmscf

R_c = 38.3 lb/mmscf

and,

R_t = (21 lbs)/(0.8 mmscf) = 26.25 lbs/mmscf

Thus,

$R_t < R_c$ → In Compliance

TABLE 5-B
SOURCE TESTING AND TUNE-UP FREQUENCY[1]

EQUIPMENT	TEST PER Q.A. PROGRAM	TEST EVERY THREE-YEAR PERIOD	TUNE-UP ONCE A YEAR	TUNE-UP TWICE A YEAR	TEST EVERY TWO CALENDAR QUARTERS	TEST EVERY FIVE-YEAR PERIOD
BOILERS AND HEATERS						
Process Units				X[4]		
Large Sources		X		X[4]		
Major Sources	X					
I.C.E.						
Process Units			X[2,5]			
Large Sources		X		X[2,5]		
Major Sources	X					
KILNS/CALCINERS						
<10 TONS/HR		X				
>10 TONS/HR	X					
TAIL GAS UNITS	X					
FCCU	X					
PORTABLE EQUIPMENT			X			
ALL OTHER EQUIPMENT[3]			X			
Super Compliant Major Source					X[6]	
Process Unit with Concentration Limit						X

1 Does not include Rule 219 Exempt Equipment.

2 To Manufacturer's Specification.

3 Does not include Equipment where combustion gases produce reducing and oxidizing conditions as part of the process (for example, metal melting furnaces which provide various alloys.

4 If a boiler or heater does not operate at all during a continuous six-month period within a compliance year, only one tune-up is required for that compliance year. No tune-up is required during a compliance year for any boiler or heater that is not operated at all during the entire compliance year. Test firings are not considered operation for the purposes of these tune-up requirements so long as such test firings are done to verify availability of the unit for their intended use and once such test firings are completed the units are shutdown. Records of the

date and duration when the unit is test fired shall be maintained for a period of three years, and shall be made accessible to the Executive Officer upon request.

5 If an ICE classified as a large NOx source does not operate at all during a continuous six-month period within a compliance year, only one tune-up is required for that compliance year. No tune-up is required during a compliance year for an ICE classified as a large NOx source or a NOx process unit that is not operated at all during the entire compliance year. Records of any operation shall be maintained for a period of three years, and shall be made accessible to the Executive Officer upon request.

6. If four consecutive bi-quarterly tests all show compliance, the testing frequency may be reduced to once per year.

TABLE 5-C
DRY F-FACTORS AND HIGHER HEATING VALUES

Fuel Type	(F_d) Dry F-Factor	(V) Higher Heating Value
Natural Gas	8710 dscf/mmBtu	1050 mmBtu/mmscf
LPG, Propane, Butane	8710 dscf/mmBtu	94 mmBtu/mgal
Diesel	9190 dscf/mmBtu	137 mmBtu/mgal
Fuel Oil	9190 dscf/mmBtu	150 mmBtu/mgal

RULE 2012 PROTOCOL-
CHAPTER 6

ALL SOURCES AND UNITS - DETERMINING

SOURCE CATEGORY STATUS

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CHAPTER 6 - ALL SOURCES AND UNITS - DETERMINING SOURCE CATEGORY STATUS

All equipment are categorized by equipment rating, mass emissions (i.e., potential to emit), and annual operating capacity (actual heat input) as shown in tables 1-A, 1-B, and 1-C. This chapter prescribes the methodology for assessing equipment rating, potential to emit, and actual heat input

The methodology for estimating mass emissions is described in Chapter 2 (Major Sources), Chapter 3 (Large Sources), and Chapter 4 (Process Units.

A. Equipment Rating

For equipment to be categorized as major source, large source, or NO_X process unit, the Facility Permit holder shall demonstrate that the affected equipment is within the range of the determined category. The following procedures are to be used in demonstrating the category status:

1. To determine the heat input rating for boilers, furnaces, ovens, dryers, heaters, incinerators, test cells, and all liquid and gaseous fueled equipment:

    a. Use the identification/rating plate permanently affixed to the equipment on which the maximum heat input rating in Btu/hr is displayed along with the serial and model numbers. If not available, then -

    b. Determine the maximum heat input rating for the burner(s) from specifications/data issued by the manufacturer, or by the burner ID plate on the equipment. If not available, then -

    c. Calculate the maximum heat input rating by multiplying the maximum hourly, fuel usage and higher heating value of the fuel(s). If multiple fuels are burned then the fuel providing the highest heat input rating must be used. This approach must be used if the equipment is capable of operating above the designed maximum heat input rating, irrespective of Chapter 6, Subdivision A, Paragraphs 1, Subparagraphs a and b.

2. To determine the brake horsepower for internal combustion engines:

    a. Use the identification/rating plate permanently affixed to the internal combustion engine on which the rated brake horsepower is specified by the manufacturer. If not available, then -

b. Calculate the brake horsepower rating of an internal combustion engine by multiplying the maximum fuel usage per minute, heating value of fuel, equipment efficiency provided by the manufacturer and the conversion factor (2545 Btu/bhp).

3. To determine process weight rating of kilns, calciners, and other process equipment use the maximum total weight of all materials introduced into any specific process, including solid fuels.

4. To determine megawatt or kilowatt ratings of turbines:

a. powering an electric generator

i. Use the identification/rating plate permanently affixed to the turbine generator on which rating is displayed. If not available, then -

ii. Use the megawatt rating for turbines as determined by the manufacturer's specification sheet. If not available, then

iii. Calculate the turbine's power rating by dividing the fuel capacity (Btu/hr) by the manufacturer's heat rate (Btu/kw-hr).

b. not powering an electric generator

i. use the identification/rating plate permanently affixed to the turbine on which the shaft brake horsepower (bhp) is displayed. If not available, then -

ii. use the shaft bhp as determined by the manufacturer's specification sheet, then -

iii. Calculate the turbine's power rating (kw) by multiplying the shaft bhp by 0.67.

5. To determine annual heat input for source-category determination:

$$H = \sum_{j=1}^{r} \sum_{k=1}^{12} D_{jk} \times V_{jk} \times 10^{-3} \qquad \text{(Eq.40)}$$

where:

H = Annual heat input (billion Btu/yr).

D_{jk} = The monthly fuel usage (mmscf/mo, mmgal/mo, mmlb/mo, mmbbl/mo)

V_{jk} = The higher heating value for each type of fuel:

j = Each type of fuel

k = Each monthly period

r = The number of different types of fuel

B. Potential to Emit

The potential to emit means the amount of pollutants calculated (1) using a calendar monthly average and (2) on a pound-per-day basis from permit conditions which directly limit the emissions or, when no such conditions are imposed from:

(1) the maximum rated capacity; and

(2) the maximum daily hours of operation; and

(3) the physical characteristics of the materials processed.

C. Actual Heat Input

The actual heat input is the measured fuel usage multiplied by the heat content of the fuel.

D. Loss of Categorization Status

On and after January 1, 1995 for Cycle 1 facilities and July 1, 1995 for Cycle 2 facilities, any Facility Permit holder who has elected to change the category of any equipment from a major to a large source or a large source to a process unit based on the level of fuel usage or hours of operation, shall monitor and record the annual fuel usage or hours of operation for that equipment.

(1) If the fuel usage or hours of operation exceed the levels specified for that equipment at the end of any RECLAIM compliance year, the Facility Permit holder of a large source shall:

(i) Within 1 month from the end of the compliance year, submit a Monitoring, Reporting and Recordkeeping (MRR) plan specifying the use of CEMS and any preliminary data, and

(ii) Within one year from the end of the compliance year, comply with the major source requirements specified in Rule 2012.

2. If the fuel usage or hours of operation exceed the levels specified for that equipment at the end of any RECLAIM compliance year, the Facility Permit holder of a process unit shall:

(i) Within 1 month from the end of the compliance year, submit a Monitoring, Reporting, and Recordkeeping (MRR) plan that specifies the concentration limit or elects for an emission rate, and

(ii) Within 3 months from the end of the compliance year, comply with the large source requirements specified in Rule 2012.

RULE 2012 PROTOCOL- CHAPTER 7

REMOTE TERMINAL UNIT (RTU)

- ELECTRONIC REPORTING

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CHAPTER 7 - REMOTE TERMINAL UNIT (RTU)

This chapter defines the tasks and characteristics for electronic reporting of emissions from all sources. The Facility Permit holder of a major source shall use an RTU to telecommunicate rule compliance data to the District Central Station Emissions Monitoring Computer. The RTU shall collect data, perform calculations, generate the appropriate data files, and transmit the data to the Central Station. The Facility Permit holder of a large source or process unit may elect to use an RTU. Alternatively, the Facility Permit holder of a large source or process unit shall compile the required rule compliance data manually, and transmit that data via modem in accordance with the data requirements of Section D in this chapter. The Facility Permit holder shall use, when required, the appropriate record type specified in this chapter to report to the District Central Station emissions from all RECLAIM NOx sources. Alternative to transmitting data to the District Central Station, the Facility Permit holder may use the District Internet Web Site to report emissions electronically from RECLAIM NOx sources except for major sources.

A. GENERAL

1. General

The Facility Permit holder of a major source shall telecommunicate rule compliance data to the District via Remote Terminal Units (RTU). This form of reporting may also be used for large sources or process units. The RTU shall collect data from a CEMS, a CPMS, or other equipment specified in the Facility Permit and send data periodically to the Central Station Emissions Monitoring Computer (Central Station).

This chapter specifies the tasks and characteristics required of the RTU and shall be used as a guide for providing the required software/hardware for the RTU. Emissions Data Collection System conformity as well as establishing and maintaining communications with the emission monitoring system and the Central Station shall be the responsibility of the Facility Permit holder. This chapter also serves as a functional guideline for operating requirements of the RTU, and provides information concerning RTU hardware/software procurement, configuration, installation, maintenance, and compatibility with the emission monitoring system and the Central Station.

2. RTU and Supporting Equipment Description

a. Purpose:

The RTU shall interface to existing data acquisition systems or other field instrumentation, and shall gather and store data, and facilitate telecommunication with the Central Station Computer.

b. Environment:

i. Logical Environment:
The signal chain includes the process equipment, sensing devices, data acquisition system, RTU, modem, communications link and District Central Station.

ii. Physical Environment:
Typical environments shall include "friendly" and "Central Station" environments. Friendly environments include clean, air conditioned areas such as computer rooms and offices. Hostile environments may include exterior spaces or interior spaces without benefit of air conditioning, and areas where free floating air particulates may impede the normal operation of exposed electronics. Each RTU shall be mounted in such a manner as to be environmentally qualified.

iii. Electrical Environment:

1) Connected Devices:

Each RTU may receive information from a local computer (DAS) or various field sensing devices, calculate and/or store the specified parameters and shall make its data available to local and Central Stations.

2) Sensor-based Data to be acquired:

Where applicable, the RTU shall be able to directly monitor transducers which sense variables required for compliance determinations. At a minimum, input analog conversion hardware should operate with a medium level of resolution (i.e. 12 bit resolution) and a sampling rate sufficient to accurately characterize the sensor based data.

iv. Description of Data to be transmitted:

All data shall be made available at data output ports in ASCII format as described below:

1) Data Sampling:

Shall retain selectable status levels about its sensors.

2) Rule-specific Data Sets:

(as specified elsewhere)

c. Functions:

The RTU shall provide the following functions:

i. Power-Up/Restart Mode:

Upon resumption of power after a loss, the RTU shall automatically restart and reset itself to predetermined system settings.

ii. Non-Communicating Mode:

When in the non-communicating mode the RTU shall operate independently of the communications ports as well as store its transactions for later communications with the Central Station.

iii. Failure Mode:

In the event the RTU is unable to initiate communications with the Central Station, the RTU shall perform the following actions:

1) The RTU shall first make four subsequent attempts to establish communications with the Central Station.

2) Upon failure of the fourth attempt, the RTU shall:

a Revert to the non-communicating mode for a period of fifteen (15) minutes and then again attempt to establish communications with the Central Station.

b Each failure shall result in the execution of the failure mode sequence.

3) Error Tolerance:

The RTU shall perform its specified functions without misinterpretation of input information, errors in output signals, damage to internal components, and loss or change of stored information with either common mode to ground or differential mode transients present on the communication ports, circuits or power sources which shall be connected to the inputs and power supply terminals to the equipment.

B. PRODUCTS

1. RTU Attributes

a. Environmental Tolerances: Each RTU shall be installed in such a manner as to be environmentally qualified for the particular physical environment.

b. Communications Provisions: The RTU shall provide a minimum of one (1) communications connection. The connection shall be labeled "Remote".

c. Real Time Clock: The RTU shall be equipped with a battery-backed Real Time Calendar/Clock (RTC) to provide time signals for implementing time dependent programs. The battery back-up shall be field replaceable and shall not require replacement more often than once every two (2) years. An alarm message shall be generated when the battery reaches a low voltage point with at least one (1) month life under load left prior to the necessity for battery replacement.

d. Internal Software:

   i. Data Collection and Storage: The RTU shall collect data from sensors, generate and store values, and perform calculations upon those values. Data shall be collected and stored in the Data Sampling memory.

   ii. Calculations and Message Storage: Calculated values and messages resulting from calculations performed upon sampled data shall be stored as ASCII data strings in memory.

e. Security Provisions:

   i. Message Security: The RTU shall utilize a standard protocol encryption method for communications with the remote Central Station incorporating error detection. The system shall not incorporate error correction. The code shall detect one hundred (100) percent of single, double and triple errors; one hundred (100) percent of burst errors of six bits or fewer; ninety- seven (97) percent of all seven-bit bursts; and ninety-eight point four (98.4) percent of all other burst as well as a substantial fraction of all random error patterns involving more than three (3) bits.

   ii. Message Checking: The RTU shall utilize bitsum checking for all messages.

f. Modem: Provide a modem connected to the Remote Central Station communication port.i.Modem Self-Test: The modem shall be capable of being operated in self testing mode automatically on a periodic basis.

g. Transient Suppression: Provide hardware, circuitry, components or extended component ratings or characteristics necessary to prevent interference to correct operation or equipment damage from induced transients which may be presented on communication circuits and power sources. Transient suppression shall utilize the latest revision of the ANSI C37.90a standard.

C. EXECUTION

1. General

a. Section (C) describes acceptable methods and practices for use in completion of this work.

b. Standards: Perform the work in accordance with the latest revisions of the following standards:

i. ANSI American National Standards Institute.

ii. UL Underwriters Laboratories.

iii. EIA Electrical Industries Association.

iv. NEMA National Electrical Manufacturers Association.

2. Project Plan

Develop a project plan for accomplishing the requirements of this installation . The plan shall include a checklist for the Submittal date .

3. Software Requirements Guideline

The Software Requirement Guideline (SRG) shall specify tasks and characteristics required of the RTU and is to be used as a guide for providing the required software for the RTU. Emissions Data Collection System conformity as well as establishing and maintaining communications with the emission monitoring system and the Central Station shall be the responsibility of the Facility Permit holder.

a. References

This guideline shall be used in conjunction with the following Rules:

Recordkeeping for Oxides of Sulfur (SO_X) Emissions

Recordkeeping for Oxides of Nitrogen (NO_X) Emissions

b. System Relation

The RTU shall be the local plant data storage and processing point in a system which is reporting data to a Central Station for evaluation to determine regulatory compliance. Data formats shall be standardized between the Central Station and all monitored emissions sources. It is the function of the RTU to convert as necessary the data stream from the local monitoring system. The fundamental operation of the RTU is to:

i. compile information from the emission monitoring system as specified in this guideline.

ii. transmit the compiled data to the Central Station on a scheduled basis.

c. Central Station Interface

On scheduled updates the RTU shall download current data to the Central Station. The RTU data buffer shall be reset after each successful download to the Central Station.

d. Software Responsibility

The Facility Permit holder shall be responsible for providing all RTU software required to perform all specified tasks. This may include purchased commercial software packages or custom written programs.

e. Product Function

i. Software Context and Data Flow Diagrams

The flow diagram at the end of this Chapter is a Context Diagram description and Data Flow Diagram which show how the different external functions tie to the RTU package. Plant data or operating information is collected by the emission monitoring system for evaluation of emissions. The RTU Unit is the process shown on this diagram and is the focus of this guideline.

Data Values relating to emissions received from the emission monitoring system are processed by the RTU into data files for transmission to the SCAQMD Central Station. The type of message is shown on the RTU Context Diagram between the RTU and the Central Station. The message is data sets which are sent periodically.

The RTU Data Flow Diagram is a graphical expansion of the RTU Unit process block. Emission monitoring system data is shown coming into the Network Driver and splitting to the other process blocks which represent RTU functions.

ii. Communication End Points

The RTU will communicate with both the emission monitoring system and the Central Station. Each end point has a different protocol and purpose. Data sent from the RTU to the Central Station shall be converted from floating point numbers used to perform calculations into ASCII standard to allow for different internal formats.

f. Specific Requirements

i. RTU Software

The main RTU program shall receive input data, do calculations (if necessary) and store all data in non-volatile memory, as it is received.

ii. Direct Field Input Data

Many RTUs may be capable of reading direct field inputs which shall consist of analog and/or digital real values. Direct field input requirements shall be specified as required for each RTU. Communications software shall be capable of supporting the hardware required to receive these inputs. If analog data cards must be installed in the RTU any resulting values provided to the RTU data bus shall range from -32768 to +32767 for unscaled values. The same accuracy as emission monitoring system network data shall be provided for analog data values scaled on the I/O device before going onto the RTU data bus.

iii. Input Data Conversion/Storage

All input values shall be stored in as received ASCII format. These values shall then be parsed and converted to real numbers for calculations and averaging.

iv. Output Data To Central Station

The context diagram displays how the RTU software shall be configured to allow messages to be sent to the Central Station. File transfer for all messages shall be in ASCII format including a bitsum check value with a return acknowledgment expected by the RTU when the Central Station has verified the bitsum check.

v. RTU To Central Station Communications Failure

If the RTU cannot communicate with the Central Station the main program shall store all calculated values and reports in a special file in non-volatile memory. These special files shall be labeled to show that they have not been acknowledged as received by the Central Station.

g. Performance Requirements

i. Speed of Receiving DATA

Incoming data from the plant or emission monitoring system shall be received at intervals specified in the appropriate emission monitoring guideline. Communication with the Central Station, Parsing, verification, storage and checking shall not block the receipt of new data.

ii. RTU Non-Volatile Memory

The RTU non-volatile memory shall have enough capacity to store all programs, data parameters, emission monitoring system input data and calculated data averages. Input data and calculated averages shall be allocated space using the first in first out (FIFO) method to store the quantity of data as required.

h. Design Restraints

i. Data Set Formats

Section (D) indicates the data format that is to be sent to the Central Station at scheduled intervals. The Central Station will send a confirmation message back for each transmission received which will consist of an identification number unique to the Central Station and a transaction number which is sequentially issued.

i. RTU External Interface Requirements

i. Central Station Interface

External interface to the RTU is shown on the Context Diagram at the end of this chapter. Central Station interface is described above as fixed format ASCII messages using a commercially available communication software package. In return the Central Station will send confirmation messages in ASCII form when a satisfactory message transfer has been completed.

4. Required Installation Practices

a. Standards: Install all devices in accordance with the standards set forth herein and in accordance with manufacturers recommendations and first class standard industry practice.

b. Telephone Interface:

RTU shall operate on a standard analog telephone line. Label the remote Central Station communications connector with the telephone number to which it is connected.

5. Submittals

a. Shop Drawing:

i. Submit two (2) copies of the following in accordance with the applicable rule compliance dates.

- A Title Sheet
- Single Line Diagrams
- Wiring Diagrams or Run Sheets
- Physical Details of Custom Assemblies

ii. Descriptions of the above shop drawings are as follows:

a) Title Sheet containing a drawing list, abbreviations list, symbols list and schedules.

b) Single-Line Diagram for each system showing signal relationships of devices within the system and device nomenclatures.

c) Wiring Diagram for each assembly or enclosure or free standing device, showing the following:

1) the layout of the devices within;

2) wiring connections;

3) wire numbers;

4) voltage levels, and

5) fuse values and types.

d) Physical Details of contractor fabricated assemblies:

1) Provide an assembly drawing showing the finished product. Show components comprising the assembly by manufacturer and model number.

2) Provide a schematic diagram of the assembly, as described above.

b. RTU Components List:

i. The RTU Component List shall contain the following information for all materials, components, devices, wire and equipment used:

- Quantity for that system.
- Description (generic).
- Manufacturers Name and Model number.

c. Software Design Description (SDD). Indicate how the developed software will meet the defined software requirements. The SDD shall be based on ANSI/IEEE standards, specifically 1016 (SDD) and 730 (Quality Assurance).

d. Software Listing. Provide a source code listing of all developed software required by the applicable emission monitoring requirements.

D. DATA REQUIREMENTS

1. General Requirements

- The District will accept data in the American Standard Code for Information Interchange (ASCII) format.
- The data file structure must be sequential. The record delimiter - a ~ (tilde) occurs only once following the end of each data record. There must be no delimiter before the first data record. The ASCII value for the delimiter is:
  ~ (decimal 126)
- Blank data records must not be reported
- In text fields, only upper case characters are to be used and must be left justified. Text fields that are not applicable must be filled with blanks. The ~ character (decimal 126) must never appear inside text fields.
- Numeric fields must be right justified and zero filled. Where decimal places are to be reported, they are to be implied - do not include the decimal point character. Numeric fields that are zeros or not applicable, must be zero filled.
- Date fields must be entered in the format "YYYYMMDD" and must always specify a valid date.

2. Data File Description

A properly composed data file is comprised of the following data records (shown indented to illustrate the logical grouping):

Code 1A	-	Transmitter Record
Code 1F	-	Facility Record
		Emission data record(s) from any of the following data records
Code 1NP	-	NO_X Process Unit and Large Source Record
Code 1NM	-	NO_X Major Source Record
Code 1SP	-	SO_X Process Unit Record
Code 1SM	-	SO_X Major Source Record
Code 1FT	-	Facility Total Record
Code 1F	-	Facility Record
		Emission data record(s)
Code 1FT	-	Facility Total Record
Code 1T	-	Final Total Record

The Code 1A data record identifies the facility submitting the data file and must be the first data record in the data file.

The Code 1T data record identifies the end of a data file and must be the last data record in the data file

The Code 1F data record identifies the facility whose emission data records are being reported.

The Code 1FT data record identifies the end of emission data records for a particular facility.

Code 1F/1FT data records must not be nested inside of another 1F/1FT group and are repeated for each facility to be reported.

Emission data records for a facility are reported following the Code 1F but before the 1FT data record for that facility and can comprise any of the following data record types:

Code 1NP	-	NO_X Process Unit and Large Source Record
Code 1NM	-	NO_X Major Source Record
Code 1SP	-	SO_X Process Unit Record
Code 1SM	-	SO_X Major Source Record

The following table summarizes valid Record Identifiers to be used starting January 1, 1998 to perform electronic reporting via a RTU or modem. The 1A through 1T records are used for identification and grouping purposes. The 1NP through 1SM records are the pre-existing emissions reporting records. Starting January 1, 1998, these records may only be used for devices which do not use multiple fuels and are not involved in multiple processes. Otherwise, sources shall report emissions by each fuel type or process conducted within the reporting period. If more than 50% of the emissions from a source is from the combustion of fuels, the emission report for such a source or process unit shall be reported based on the fuel combusted. Otherwise, emissions shall be reported based on the Source Classification Code (SCC) for the process conducted. The 1NPF through 1SUQ records are utilized for reporting emissions from devices with multiples fuels or processes. Record Identifiers starting with “2” are used to make corrections to submitted electronic emissions reports. Record Identifiers starting with “3” are used to delete previously submitted electronic emissions reports which were filed erroneously. Erroneous records to be corrected need not be deleted first.

Record Identifiers Summary Table

Record Identifier for			Description
Adding a record	**Updating a record**	**Deleting a record**	
1A*	--	--	Transmitter Record
1F*	--	--	Facility Record
1FT*	--	--	Facility Total Record
1T*	--	--	Final Total Record
1NP*	2NP	3NP	NOx Emissions Report for Process Units
1NL*	2NL	3NL	NOx Emissions Report for Large Sources
1NM*	2NM	3NM	NOx Emissions Report for Major Sources
1SP*	2SP	3SP	SOx Emissions Report for Process Units
1SM*	2SM	3SM	SOx Emissions Report for Major Sources
1NPF	2NPF	3NPF	NOx Emissions Report for Process Units by Fuel Type
1SPF	2SPF	3SPF	SOx Emissions Report for Process Units by Fuel Type
1NLF	2NLF	3NLF	NOx Emissions Report for Large Sources by Fuel Type
1NMF	2NMF	3NMF	NOx Emissions Report for Major Sources by Fuel Type
1SMF	2SMF	3SMF	SOx Emissions Report for Major Sources by Fuel Type
1NPS	2NPS	3NPS	NOx Emissions Report for Process Units by SCC
1SPS	2SPS	3SPS	SOx Emissions Report for Process Units by SCC
1NLS	2NLS	3NLS	NOx Emissions Report for Large Sources by SCC
1NMS	2NMS	3NMS	NOx Emissions Report for Major Sources by SCC
1SMS	2SMS	3SMS	SOx Emissions Report for Major Sources by SCC
1NMM	2NMM	3NMM	Monthly NOx Emissions Report for Major Sources

Record Identifiers Summary Table (Continued)

Record Identifier for			Description
Adding a record	**Updating a record**	**Deleting a record**	
1SMM	2SMM	3SMM	Monthly SOx Emissions Report for Major Sources
1NMQ	2NMQ	3NMQ	Quarterly NOx Emissions Report for Major Sources
1SMQ	2SMQ	3SMQ	Quarterly SOx Emissions Report for Major Sources
1NLQ	2NLQ	3NLQ	Quarterly NOx Emissions Report for Large Sources
1NRF	2NRF	3NRF	Quarterly NOx Emissions Report by fuel type for Rule 219 Exempt Equipment
1SRF	2SRF	3SRF	Quarterly SOx Emissions Report by fuel type for Rule 219 Exempt Equipment
1NRS	2NRS	3NRS	Quarterly NOx Emissions Report by SCC for Rule 219 Exempt Equipment
1SRS	2SRS	3SRS	Quarterly SOx Emissions Report by SCC for Rule 219 Exempt Equipment
1NVF	2NVF	3NVF	Quarterly NOx Emissions Report by fuel type for Equipment Operating under a Various Locations Permit
1SVF	2SVF	3SVF	Quarterly SOx Emissions Report by fuel type for Equipment Operating under a Various Locations Permit
1NVS	2NVS	3NVS	Quarterly NOx Emissions Report by SCC for Equipment Operating under a Various Locations Permit
1SVS	2SVS	3SVS	Quarterly SOx Emissions Report by SCC for Equipment Operating under a Various Locations Permit
1NWF	2NWF	3NWF	Quarterly NOx Emissions Report by fuel type for Equipment Operating Without Permit or District assigned Device IDs
1SWF	2SWF	3SWF	Quarterly SOx Emissions Report by fuel type for Equipment Operating Without Permit or District assigned Device IDs
1NWS	2NWS	3NWS	Quarterly NOx Emissions Report by SCC for Equipment Operating Without Permit or District assigned Device IDs
1SWS	2SWS	3SWS	Quarterly SOx Emissions Report by SCC for Equipment Operating Without Permit or District assigned Device IDs
1NPQ	2NPQ	3NPQ	Quarterly NOx Aggregate Emissions Report for Process Units
1SPQ	2SPQ	3SPQ	Quarterly SOx Aggregate Emissions Report for Process Units
1NXQ	2NXQ	3NXQ	Quarterly NOx Aggregate Emissions Report for Rule 219 Exempt Equipment
1SXQ	2SXQ	3SXQ	Quarterly SOx Aggregate Emissions Report for Rule 219 Exempt Equipment

* Previously defined codes

Record Identifiers Summary Table (Continued)

Record Identifier for			**Description**
Adding a record	**Updating a record**	**Deleting a record**	
1NTQ	2NTQ	3NTQ	Quarterly NOx Aggregate Emissions Report for Equipment Operating under a Various Locations Permit
1STQ	2STQ	3STQ	Quarterly SOx Aggregate Emissions Report for Equipment Operating under a Various Locations Permit
1NUQ	2NUQ	3NUQ	Quarterly NOx Aggregate Emissions Report for Equipment Operating without a Permit
1SUQ	2SUQ	3SUQ	Quarterly SOx Aggregate Emissions Report for Equipment Operating without a Permit

* Previously defined codes

Code 1A - Transmitter Record

The Code 1A data record is used to identify the facility submitting the data file and must be the first data record reported.

Location	Field	Length	Description
1-4	Record Identifier	4	Constant "1A" followed by 2 blanks.
5-10	SCAQMD Facility ID	6	The 6-digit SCAQMD facility ID of the facility submitting the data file.
11-128	Filler	118	Blanks , used to fill unused remaining record positions.

Code 1F - Facility Record

The Code 1F data record is used to identify the facility whose emissions are being reported.

Location	Field	Length	Description
1-4	Record Identifier	4	Constant "1F" followed by 2 blanks.
5-10	SCAQMD Facility ID	6	The 6-digit SCAQMD facility ID for the facility whose emissions are being reported.
11-128	Filler	118	Blanks , used to fill unused remaining record positions.

Code 1FT - Facility Total Record

The Code 1FT data record is used to identify the end of data emission records for a facility.

Location	Field	Length	Description
1-4	Record Identifier	4	Constant "1FT" followed by 1 blank.
5-11	Number of Emission Data Records	7	The total number of emission data records reported for the facility (excluding the 1F and the 1FT data records). Right justify and zero fill.
12-128	Filler	117	Blanks , used to fill unused remaining record positions.

Code 1T - Final Total Record

The Code 1T data record is used to identify the end of the data file and must be the last data record reported.

Location	Field	Length	Description
1-4	Record Identifier	4	Constant "1T" followed by 2 blanks
5-11	Number of Data	7	The total number of data records reported (including the Code 1T) in the data file. Right justify and zero fill.
12-128	Filler	117	Blanks , used to fill unused remaining record positions.

Code 1NP and 1NL- NO_X Process Unit and Large Source Record

The Code 1NP data record is used to report NO_X emissions from NO_X Process Units with SCAQMD assigned Device Ids. The Code 1NL data record is used to report NOx emissions from NOx Large Sources with SCAQMD assigned Device IDs. Starting January 1, 1998, these records shall only be used for devices which do not use multiple fuels and are not involved in multiple processes.

Location	Field	Length	Description
1-4	Record Identifier	4	"1NP" or "1NL"followed by 1 blank
5-10	SCAQMD Device ID	6	The SCAQMD assigned Device IDs for the equipment source. Left justify and fill with blanks
11-18	Date Emitted	8	The date emitted in the format "YYYYMMDD"
19-27	Total Emission	9(#######.##)	The total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
28 - 128	Filler	101	Blanks , used to fill unused remaining record positions

Code 1NM - NOx Major Source Record

The Code 1NM data record is used to report NO_X emissions from Major NO_X sources with SCAQMD assigned Device IDs. Starting January 1, 1998, this record shall only be used for devices which do not use multiple fuels and are not involved in multiple processes.

Location	Field	Length	Description
1-4	Record Identifier	4	Constant "1NM" followed by 1 blank
5-10	SCAQMD Device ID	6	The SCAQMD assigned Device IDs for the equipment source. Left justify and fill with blanks
11-18	Date Emitted	8	The date emitted in the format "YYYYMMDD"
19-27	Total Emission	9(#######.##)	The total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
28-36	Status Word	9	The nine character status word for the reporting day from the Status Word Table.
37 - 128	Filler	92	Blanks , used to fill unused remaining record positions

Code 1SP - SO_X Process Unit Record

The Code 1SP data record is used to report SOx emissions from SOx Process Units with SCAQMD assigned Device IDs. Starting January 1, 1998, this record shall only be used for devices which do not use multiple fuels and are not involved in multiple processes.

Location	Field	Length	Description
1-4	Record Identifier	4	Constant "1SP"followed by 1 blank
5-10	SCAQMD Device ID	6	The SCAQMD assigned Device IDs for the equipment source. Left justify and fill with blanks
11-18	Date Emitted	8	The date emitted in the format "YYYYMMDD"
19-27	Total Emission	9(#######.##)	The total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
28 - 128	Filler	101	Blanks , used to fill unused remaining record positions

Code 1SM - SOx Major Source Record

The Code 1SM data record is used to report SOx emissions from Major SOx sources with SCAQMD assigned Device IDs. Starting January 1, 1998, this record shall only be used for devices which do not use multiple fuels and are not involved in multiple processes.

Location	Field	Length	Description
1-4	Record Identifier	4	Constant "1SM" followed by 1 blank
5-10	SCAQMD Device ID	6	The SCAQMD assigned Device IDs for the equipment source. Left justify and fill with blanks
11-18	Date Emitted	8	The date emitted in the format "YYYYMMDD"
19-27	Total Emission	9(#######.##)	The total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
28-36	Status Word	9	The nine character status word for the reporting day from the Status Word Table.
37 - 128	Filler	92	Blanks , used to fill unused remaining record positions

Code 1NMF and 1SMF - NOx and SOx Major Source Emissions Report by Fuel Type

The Codes 1NMF and 1SMF data records are used to report NOx and SOx emissions by fuel type from Major SOx sources with SCAQMD assigned Device IDs. Starting January 1, 1998, these records shall be used to report emissions from each Major SOx sources and each fuel used during a reporting day.

Location	Field	Length	Description
1-4	Record Identifier	4	1NMF or 1SMF
5-10	SCAQMD Device ID	6	The SCAQMD assigned Device IDs for the equipment source. Left justify and fill with blanks
11-18	Date Emitted	8	The date emitted in the format "YYYYMMDD"
19-38	Fuel Type	20	Code for Fuel Type utilized. Left justified, blank filled
39-47	Total Emission	9(#######.##)	The total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
48-56	Status Word	9	The nine character status word for the reporting day from the Status Word Table.
57 - 128	Filler	72	Blanks , used to fill unused remaining record positions

Code 1NMS and 1SMS - NOx and SOx Major Source Emissions Report by SCC

The Codes 1NMS and 1SMS data records are used to report NOx and SOx emissions by Source Classification Codes (SCC) from Major SOx sources with SCAQMD assigned Device IDs. Starting January 1, 1998, these records shall be used to report emissions from each Major SOx sources and each process conducted during a reporting day.

Location	Field	Length	Description
1-4	Record Identifier	4	1NMS or 1SMS
5-10	SCAQMD Device ID	6	The SCAQMD assigned Device IDs for the equipment source. Left justify and fill with blanks
11-18	Date Emitted	8	The date emitted in the format "YYYYMMDD"
19-26	SCC	8	Source Classification Code
27-35	Total Emission	9(#######.##)	The total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
36-44	Status Word	9	The nine character status word for the reporting day from the Status Word Table.
45 - 128	Filler	84	Blanks , used to fill unused remaining record positions

Code 1NLF, 1NPF and 1SPF - NOx Large Source and NOx and SOx Process Unit Emissions Report by Fuel Type

The Codes 1NLF, 1NPF and 1SPF data records are used to report NOx and SOx emissions by fuel type from NOx Large source, NOx and SOx Process Units, respectively, with SCAQMD assigned Device IDs. Starting January 1, 1998, these records shall be used to report emissions from each device and each fuel used during a reporting period.

Location	Field	Length	Description
1-4	Record Identifier	4	1NLF, 1NPF, or 1SPF
5-10	SCAQMD Device ID	6	The SCAQMD assigned Device IDs for the equipment source. Left justify and fill with blanks
11-18	Date Emitted	8	End date of reporting period in the format "YYYYMMDD"
19-38	Fuel Type	20	Code for Fuel Type utilized. Left justified, blank filled
39-47	Total Emission	9(#######.##)	The total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
48-56	Status Word	9	The nine character status word for the reporting day from the Status Word Table.
57 - 128	Filler	72	Blanks , used to fill unused remaining record positions

Code 1NLS, 1NPS and 1SPS - NOx Large Source and NOx and SOx Process Units Emissions Report by SCC

The Codes 1NLS, 1NPS and 1SPS data records are used to report NOx and SOx emissions by SCC from NOx Large source, NOx and SOx Process Units, respectively, with SCAQMD assigned Device IDs. Starting January 1, 1998, these records shall be used to report emissions from each device and each process conducted during a reporting period.

Location	Field	Length	Description
1-4	Record Identifier	4	1NLS, 1NPS, or 1SMS
5-10	SCAQMD Device ID	6	The SCAQMD assigned Device IDs for the equipment source. Left justify and fill with blanks
11-18	Date Emitted	8	End date of reporting period in the format "YYYYMMDD"
19-26	SCC	8	Source Classification Code
27-35	Total Emission	9(#######.##)	The total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
36-44	Status Word	9	The nine character status word for the reporting day from the Status Word Table.
45 - 128	Filler	84	Blanks , used to fill unused remaining record positions

Code 1NMM, 1SMM, 1NMQ, 1NLQ, 1NPQ, 1SMQ, and 1SPQ - Aggregate Emissions Reports for Devices with District Assigned Device IDs

The Codes 1NMM and 1SMM data records are used to report monthly total NOx and SOx emissions, respectively, from all NOx and SOx Major Sources within a facility. The Codes 1NMQ, 1SMQ, 1NLQ, 1NPQ, and 1SPQ data records are used to report quarterly total NOx and SOx emissions, respectively, from all NOx and SOx Major, NOx Large Sources, and NOx and SOx Process Units within a facility. Starting January 1, 1998, these records shall be used to report aggregate emissions from applicable classification of devices within each facility.

Location	Field	Length	Description
1-4	Record Identifier	4	1NMM, 1SMM, 1NMQ, 1SMQ, 1NLQ, 1NPQ, or 1SPQ
5-12	Date Emitted	8	End date of the reporting period in the format "YYYYMMDD"
13-21	Total Emission	9(#######.##)	Enter the total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
22 - 128	Filler	107	Blanks , used to fill unused remaining record positions

Code 1NXQ, 1SXQ, 1NTQ, 1STQ, 1NUQ, and 1SUQ - Aggregate Quarterly Emissions Reports for Devices without District Assigned Device IDs

The Code 1NXQ, 1SXQ, 1NTQ, 1STQ, 1NUQ, and 1SUQ data records are used to report quarterly total NOx and SOx emissions, respectively, from all Rule 219 exempt equipment, equipment operating under a various locations permit (e.g. rental equipment) and equipment without permit. Starting January 1, 1998, these records shall be used to report aggregate emissions from all applicable devices within each facility.

Location	Field	Length	Description
1-4	Record Identifier	4	1NXQ, 1SXQ, 1NTQ, 1STQ, 1NUQ, and 1SUQ
5-12	Date Emitted	8	End date of the reporting period in the format "YYYYMMDD"
13-21	Total Emission	9(#######.##)	Enter the total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
22 - 128	Filler	107	Blanks , used to fill unused remaining record positions

Code 1NVF and 1SVF - NOx and SOx Emissions Reports by Fuel Type for Equipment Operated under a Various Locations Permit

The Code 1NVF and 1SVF data records are used to report NOx and SOx emissions, respectively, by fuel type from each device operating under a various location permit (e.g. rental equipment). Starting January 1, 1998, these records shall be used to report emissions from each device in this category.

Location	Field	Length	Description
1-4	Record Identifier	4	1NVF or 1SVF
5-10	Permit Number	6	SCAQMD Permit Number. Left justified, blank filled
11-18	Date Emitted	8	End date of the reporting period in the format "YYYYMMDD"
19-38	Fuel Type	20	Code for Fuel Type utilized. Left justified, blank filled
39-47	Total Emission	9(#######.##)	Enter the total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
47 - 128	Filler	82	Blanks , used to fill unused remaining record positions

Code 1NVS and 1SVS - NOx and SOx Emissions Reports by SCC for Equipment Operated under a Various Locations Permit

The Code 1NVF and 1SVF data records are used to report NOx and SOx emissions, respectively, by SCC from each device operating under a various location permit (e.g. rental equipment). Starting January 1, 1998, these records shall be used to report emissions from each device in this category.

Location	Field	Length	Description
1-4	Record Identifier	4	1NVS or SVS
5-10	Permit Number	6	SCAQMD Permit Number. Left justified, blank filled
11-18	Date Emitted	8	End date of the reporting period in the format "YYYYMMDD"
19-26	SCC	8	Source Classification Code.
27-35	Total Emission	9(#######.##)	Enter the total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
36 - 128	Filler	93	Blanks , used to fill unused remaining record positions

Code 1NRF, 1SRF, 1NWF, and 1SWF - NOx and SOx Emissions Reports by Fuel Type for Rule 219 Exempt Equipment, and Equipment Operated without a Permit

Code 1NRF, 1SRF, 1NWF, and 1SWF are used to report NOx and SOx emissions by fuel type from all devices which are exempt from permit under Rule 219 or from all devices operating without a permit. Starting January 1, 1998, these records shall be used to report emissions from all devices in each of these category.

Location	Field	Length	Description
1-4	Record Identifier	4	1NRF, 1SRF, 1NWF, or 1SWF
5-12	Date Emitted	8	End date of the reporting period in the format "YYYYMMDD"
13-32	Fuel Type	20	Code for Fuel Type utilized. Left justified, blank filled
33-41	Total Emission	9(#######.##)	Enter the total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
42 - 128	Filler	82	Blanks , used to fill unused remaining record positions

Code 1NRS, 1SRS, 1NWS, and 1SWS - NOx and SOx Emissions Reports by SCC for Rule 219 Exempt Equipment, and Equipment Operated without a Permit

Code 1NRS, 1SRS, 1NWS, and 1SWS are used to report NOx and SOx emissions by SCC from all devices which are exempt from permit under Rule 219 or from all devices operating without a permit. Starting January 1, 1998, these records shall be used to report emissions from all devices in each of these category.

Location	Field	Length	Description
1-4	Record Identifier	4	1NRS, 1SRS, 1NWS, or 1SWS
5-12	Date Emitted	8	End date of the reporting period in the format "YYYYMMDD"
13-20	SCC	8	Source Classification Code.
21-29	Total Emission	9(#######.##)	Enter the total emission in lb to 2 decimal places. Omit the decimal point, right justify and zero fill. No negative numbers.
30-128	Filler	99	Blanks , used to fill unused remaining record positions

Status Word Table

The Status Word Table is used to compile the status word for the required reporting period. True is 1 and False is 0.

Location	Field	Length	Description
1-1	Valid Data	1	Enter true if valid data was obtained for the entire reporting period, else enter false
2-2	Calibration	1	Enter true if the monitoring system was calibrated during the reporting period, else enter false
3-3	Off-line	1	Enter true if the monitoring system was off-line at any time during the reporting period, else enter false.
4-4	Alternate Data Acquisition	1	Enter true if alternate data acquisition was used during the reporting period, else enter false.
5-5	Out of Control	1	Enter true if the CEMS was out of control during the reporting period, else enter false.
6-6	Fuel Switch	1	Enter true if more than one fuel type was used during the reporting period, else enter false.
7-7	10% range	1	Enter true if concentration was reported at 10% valid range when concentration value was below 10%, else enter false.
8-8	lower than 10% range	1	Enter true if concentration was reported at an actual value less than 10% valid range, else enter false.
9-9	non-operational	1	Enter true if the RECLAIM NOx source being monitored is non-operational for the entire day, else enter false.

Format for Correcting Emissions Reports

Name	Description
Record Identifier	Record Identifier starting with “2”
Record to be corrected	All information contained in previously submitted record which is to be corrected, except the original Record Identifier field and the filler field.
Correct Record	The correct record containing all information for the record type, except the original Record Identifier field and the filler field.
Filler	This field is blank filled to complete the 128 character fixed length reporting record.

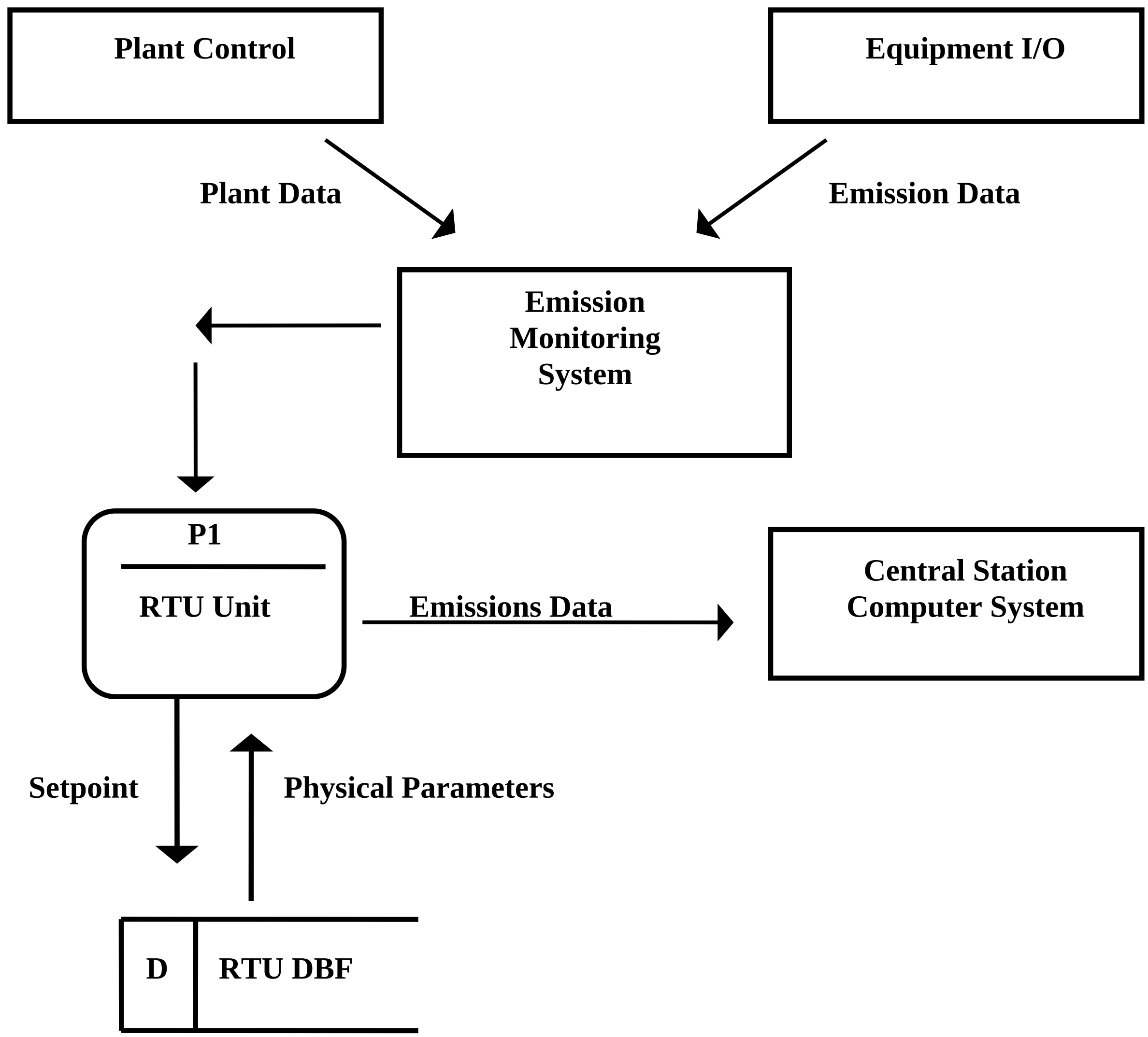
Format for deleting Emissions Reports

Name	Description
Record Identifier	Record Identifier starting with “3”
Record to be deleted	All information contained in previously submitted record which is to be deleted, except the original Record Identifier field and the filler field.

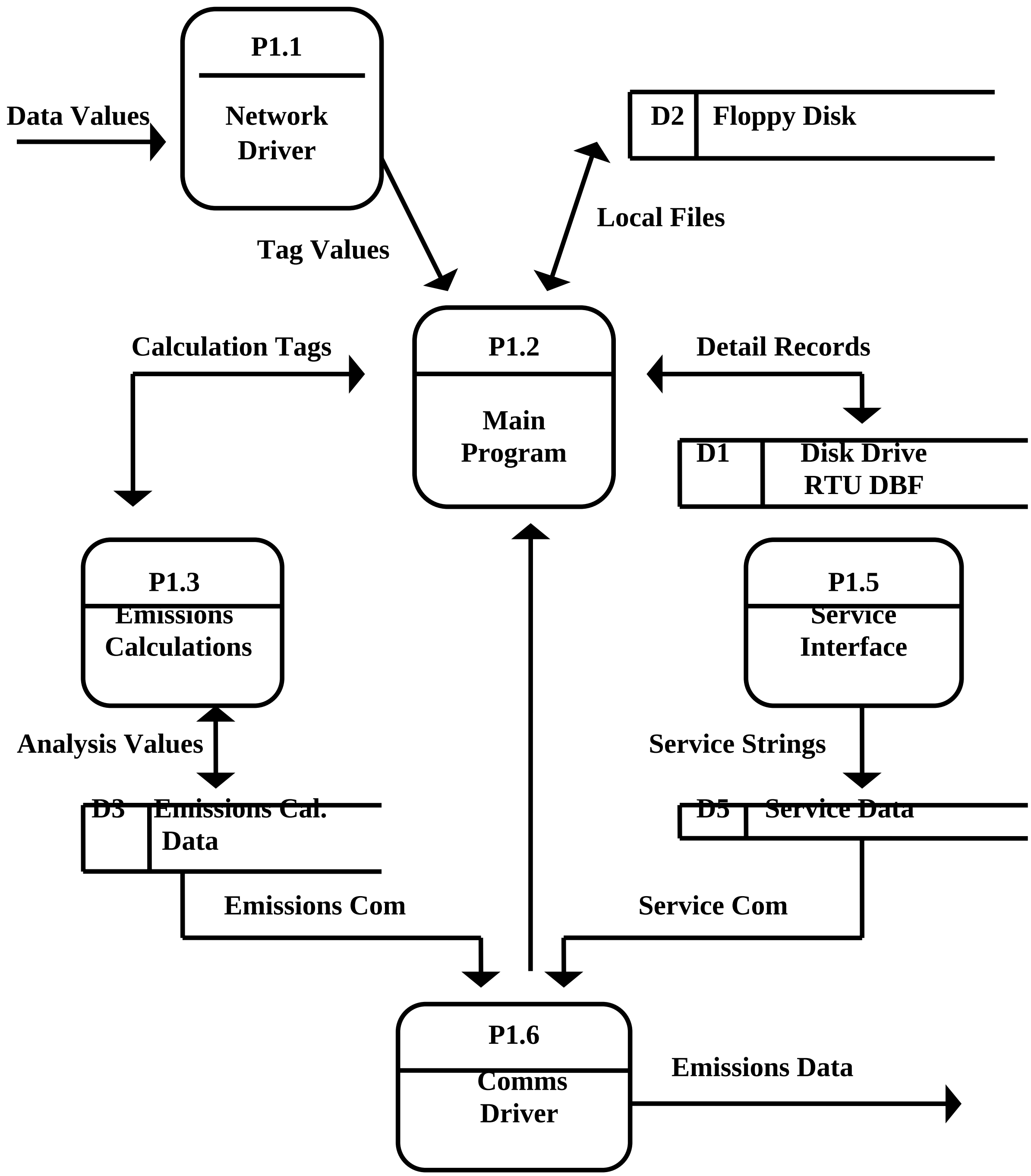
APPENDIX G

DIAGRAMS

RTU Context Diagram



RTU Data Flow Diagram



RULE 2012 PROTOCOL
CHAPTER 8

REFERENCE METHODS

District Method 1.1 - Sample and velocity traverses for stationary sources

District Method 1.2 Sample and velocity traverse for stationary sources with small stacks or ducts

District Method 2.1 - Determination of stack gas velocity and volumetric flow rate (s-type Pitot tube)

District Method 2.2 - Direct measurement of gas volume through pipes and small ducts

District Method 2.3 - Determination of gas velocity and volumetric flow rate from small stacks or ducts

District Method 3.1 - Gas analysis for dry molecular weight and excess air

District Method 4.1 - Determination of moisture content in stack gases

District Method 7.1 - Determination of nitrogen oxide emissions from stationary sources

District Method 100.1 - Instrumental analyzer procedures for continuous gaseous emission sampling

EPA Method 19 - Determination of sulfur dioxide removal efficiency and particulate, sulfur dioxide and nitrogen oxides emission rates from electric utility steam generator (40 CFR Part 60 Appendix A)

RULE 2012 PROTOCOL- ATTACHMENT A

1 N PROCEDURES

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ATTACHMENT A - 1N PROCEDURE

ATTACHMENT A
1 N PROCEDURE

A. APPLICABILITY

1. This procedure may be used to provide substitute data for affected sources that meet the specified conditions in Chapter 2, Subdivision E, Paragraph 1, Subparagraph b, Clause i, Chapter 2, Subdivision E, Paragraph 2, Subparagraph b, Clause i, and Chapter 3, Subdivision I, Paragraph 2, Subparagraph a.

B. PROCEDURE

1. Where N is the number of hours of missing emissions data, determine the substitute hourly NO_X concentration (in ppmv), or the hourly flow rate (in scfh) by averaging the measured or substituted values for the 1N hours immediately before the missing data period and the 1N hours immediately after the missing data period.

2. Where 1N hours before or after the missing data period includes a missing data hour, the substituted value previously recorded for such hour(s) pursuant to the missing data procedure shall be used to determine the average in accordance with Subdivision B, Paragraph 1 above.

3. Substitute the calculated average value for each hour of the N hours of missing data.

EXAMPLES OF 1 N PROCEDURE

EXAMPLE 1

HOUR	DATA POINT (LB/HR)
1:00 A.M.	30
2:00 A.M.	25
3:00 A.M.	32
4:00 A.M.	34
5:00 A.M.	Missing
6:00 A.M.	Missing
7:00 A.M.	Missing
8:00 A.M.	27
9:00 A.M.	22
10:00 A.M.	25
11:00 A.M.	30

To fill in the missing three hours, take the data points from the 3 hours before and the 3 hours after the missing data period to determine an average emission over the 3 hours

$$\text{average emissions} = \frac{25 + 32 + 34 + 27 + 22 + 25}{6} = 27.5 \text{ lb/hr.}$$

The filled in data set should read as follows:

EXAMPLE 1 (continued)

HOUR	DATA POINT (LB/HR)
1:00 A.M.	30
2:00 A.M.	25
3:00 A.M.	32
4:00 A.M.	34
5:00 A.M.	27.5
6:00 A.M.	27.5
7:00 A.M.	27.5
8:00 A.M.	27
9:00 A.M.	22
10:00 A.M.	25
11:00 A.M.	30

EXAMPLES OF 1 N PROCEDURE

EXAMPLE 2

HOUR	DATA POINT (LB/HR)
1:00 A.M.	45
2:00 A.M.	50
3:00 A.M.	53
4:00 A.M.	Missing
5:00 A.M.	Missing
6:00 A.M.	Missing
7:00 A.M.	58
8:00 A.M.	Missing
9:00 A.M.	48
10:00 A.M.	45

In this example the missing data point at 8 A.M. is in the 3-hour period after the 3- hour missing data period. We first fill the 8.A.M. slot.

average emissions for 8 A.M. $= \dfrac{58 + 48}{2} = 53$

The filled in data sheet at this point should read as follows:

EXAMPLE 2 (continued)

HOUR	DATA POINT (LB/HR)
1:00 A.M.	45
2:00 A.M.	50
3:00 A.M.	53
4:00 A.M.	Missing
5:00 A.M.	Missing
6:00 A.M.	Missing
7:00 A.M.	58
8:00 A.M.	53
9:00 A.M.	48
10:00 A.M.	45

The average for the three hour missing data period is:

average emissions $= \dfrac{45 + 50 + 53 + 58 + 53 + 48}{6} = 51.2$

The completed filled in data sheet should read as follows:

EXAMPLE 2 (continued)

HOUR	DATA POINT (LB/HR)
1:00 A.M.	45
2:00 A.M.	50
3:00 A.M.	53
4:00 A.M.	51.2
5:00 A.M.	51.2
6:00 A.M.	51.2
7:00 A.M.	58
8:00 A.M.	53
9:00 A.M.	48
10:00 A.M.	45

RULE 2012 PROTOCOL-ATTACHMENT B

BIAS TEST

ATTACHMENT B

BIAS TEST

The bias of the data shall be determined based on the relative accuracy (RA) test data sets and the relative accuracy (RATA) test audit data sets for NO_X pollutant concentration monitors, fuel gas sulfur content monitors, flow monitors, and emission rate measurement systems using the procedures outlined below.

1. Calculate the mean of the difference using Equation 2-1 of 40 CFR, Part 60, Appendix B, Performance Specification 2. To calculate bias for a NO_X pollutant concentration monitor, "d" shall, for each paired data point, be the difference between the NO_X concentration values (in ppmv) obtained from the reference method and the monitor. To calculate bias for a flow monitor, "d" shall, for each paired data point, be the difference between the flow rate values (in scfh) obtained from the reference method and the monitor. To calculate bias for an emission rate measurement system, "d" shall, for each paired data point, be the difference between the emission rate values (in lb/hr) obtained from the reference method and the monitoring system.

2. Calculate the standard deviation, S_d, of the data set using Equation 2-2 of 40 CFR, Part 60, Appendix B, Performance Specification 2.

3. Calculate the confidence coefficient, cc, of the data set using Equation 2-3 of 40 CFR, Part 60, Appendix B, Performance Specification 2.

4. The monitor passes the bias test if it meets either of the following criteria:

   a. the absolute value of the mean difference is less than |cc|.

   b. the absolute value of the mean difference is less than 1 ppmv.

5. Alternatively, if the monitoring device fails to meet the bias test requirement, the Facility Permit holder may choose to use the bias adjustment procedure as follows:

   a. If the CEMS is biased high relative to the reference method, no correction will be applied.

   b. If the CEMS is biased low relative to the reference method, the data shall be corrected for bias using the following procedure:

$$CEM_i^{adjusted} = CEM_i^{monitored} \times BAF \qquad \text{(Eq. B-1)}$$

where:

$CEM_i^{adjusted}$ = Data value adjusted for bias at time i.

$CEM_i^{monitored}$ = Data provided by the CEMS at time i.

BAF = Bias Adjustment Factor

$$BAF = 1 + (|d|/CEM) \qquad \text{(Eq. B-2)}$$

where:

d = Arithmetic mean of the difference between the CEMS and the reference method measurements during the determination of the bias.

CEM = Mean of the data values provided by the CEMS during the determination of bias.

If the bias test failed in a multi-level RA or RATA, calculate the BAF for each operating level. Apply the largest BAF obtained to correct for the CEM data output using equation B-1. The facility permit holder shall have the option to apply this adjustment to either all directly monitored data or to emission rates from the time and date of the failed bias test until the date and time of a RATA that does not show bias. These adjusted values shall be used in all forms of missing data computation, and in calculating the mass emission rate.

The BAF is unique for each CEMS. If backup CEMS is used, any BAF applied to primary CEMS shall be applied to the backup CEMS unless there are RATA data for the backup CEMS within the previous year.

If the BAF changes during a RATA, the new BAF must be applied to the emissions data from the time and date of the RATA until the time and date of the next RATA.

3/17/17

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

RULE 2012 PROTOCOL-ATTACHMENT C

QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

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ATTACHMENT C - QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

ATTACHMENT C

QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

A. Quality Control Program

Develop and implement a quality control program for the continuous emission monitoring systems and their components. As a minimum, include in each quality control program a written plan that describes in detail complete, step-by-step procedures and operations for each of the following activities:

1. Calibration Error Test Procedures

   Identify calibration error test procedures specific to the CEMS that may require variance from the procedures used during certification (for example, how the gases are to be injected, adjustments of flow rates and pressures, introduction of reference values, length of time for injection of calibration gases, steps for obtaining calibration error, determination of interferences, and when calibration adjustments should be made).

2. Calibration and Linearity Adjustments

   Explain how each component of the CEMS will be adjusted to provide correct responses to calibration gases, reference values, and/or indications of interference both initially and after repairs or corrective action. Identify equations, conversion factors, assumed moisture content, and other factors affecting calibration of each CEMS.

3. Preventative Maintenance

   Keep a written record of procedures, necessary to maintain the CEMS in proper operating condition and a schedule for those procedures.

4. Audit Procedures

   Keep copies of written reports received from testing firms/laboratories of procedures and details specific to the installed CEMS that were to be used by the testing firms/laboratories for relative accuracy test audits, such as sampling and analysis methods. The testing firms/laboratories shall have received approval from the District by going through the District's laboratory approval program.

5. Record Keeping Procedures

Keep a written record describing procedures that will be used to implement the record keeping and reporting requirements.

Specific provisions of Section A-3 and A-5 above of the quality control programs shall constitute specific guidelines for facility personnel. However facilities shall be required to take reasonable steps to monitor and assure implementation of such specific guidelines. Such reasonable steps may include periodic audits, issuance of periodic reminders, implementing training classes, discipline of employees as necessary, and other appropriate measures. Steps that a facility commits to take to monitor and assure implementation of the specific guidelines shall be set forth in the written plan and shall be the only elements of Section A-3 and A-5 that constitute enforceable requirements under the written plan, unless other program provisions are independently enforceable pursuant to other requirements of the NO_X protocols or District or federal rules or regulations.

B. FREQUENCY OF TESTING

There are three situations which will result in an out-of-control period. These include failure of a calibration error test, failure of a relative accuracy test audit, and failure of a BIAS test, and are detailed in this subdivision. Data collected by a CEMS during an out-of-control period shall not be considered valid.

The frequency at which each quality assurance test must be performed is as follows:

1. Periodic Assessments

For each monitor or CEMS, perform the following assessments on each day during which the unit combusts any fuel or processes any material (hereafter referred to as a "unit operating day"), or for a monitor or a CEMS on a bypass stack/duct, on each day during which emissions pass through the bypass stack or duct. These requirements are effective as of the date when the monitor or CEMS completes certification testing.

a. Calibration Error Testing Requirements for Pollutant Concentration Monitors and O_2 Monitors

Test, record, and compute the calibration error of each NO_X pollutant concentration monitor and O_2 monitor at least once on each unit operating day, or for monitors or monitoring systems on bypass stacks/ducts on each day that emissions pass through the bypass stack or duct. Conduct calibration error checks, to the extent practicable, approximately 24 hours apart. Perform the daily calibration error test according to the procedure in Paragraph B.1.a.ii. of this Attachment.

For units with more than one span range, perform the daily calibration error test on each scale that has been used since the last calibration error test. For example, if the emissions concentration has not exceeded the low-scale span range since the previous calendar day, the calibration error test may be performed on the low-scale only. If, however, the emissions concentration has exceeded the low-scale span range since the previous calibration error test, perform the calibration error test on both the low- and high-scales

i. Design Requirements for Calibration Error Testing of NO_X Concentration Monitors and O_2 Monitors

Design and equip each NO_X concentration monitor and O_2 monitor with a calibration gas injection port that allows a check of the entire measurement system when calibration gases are introduced. For extractive and dilution type monitors, all monitoring components exposed to the sample gas, (for example, sample lines, filters, scrubbers, conditioners, and as much of the probe as practical) are included in the measurement system. For in situ type monitors, the calibration must check against the injected gas for the performance of all electronic and optical components (for example, transmitter, receiver, analyzer).

Design and equip each pollutant concentration monitor and O_2 monitor to allow daily determinations of calibration error (positive or negative) at the zero-level (0 to 20 percent of each span range) and high-level (80 to 100 percent of each span range) concentrations.

ii. Calibration Error Test for NO_X Concentration Monitors and O_2 Monitors

Measure the calibration error of each NO_X concentration analyzer and O_2 monitor once each day according to the following procedures:

If any manual or automatic adjustments to the monitor settings are made, conduct the calibration error test in a way that the magnitude of the adjustments can be determined and recorded.

Perform calibration error tests at two concentrations: (1) zero-level and (2) high level. Zero level is 0 to 20 percent of each span range, and high level is 80 to 100 percent of each span range. All calibration gases used during certification tests and quality assurance and quality control activities shall be NIST/EPA approved standard reference materials (SRM), certified reference materials CRM), or shall be certified according to "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," September 1997, EPA 600/R-97/121 or any subsequent version published by EPA.

Introduce the calibration gas at the gas injection port as specified above. Operate each monitor in its normal sampling mode. For extractive and dilution type monitors, pass the audit gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling and through as much of the sampling probe as practical. For in situ type monitors, perform calibration checking all active electronic and optical components, including the transmitter, receiver, and analyzer. Challenge the NO_X concentration monitors and the O_2 monitors once with each gas. Record the monitor response from the data acquisition and handling system. Use the following equation to determine the calibration error at each concentration once each day:

$$CE = \frac{|R-A|}{S} \times 100 \qquad \text{(Eq. C-1)}$$

Where:

CE = The percentage calibration error based on the span range

R = The reference value of zero- or high-level calibration gas introduced into the monitoring system.

A = The actual monitoring system response to the calibration gas.

S = The span range of the instrument

b. Calibration Error Testing Requirements for Stack Flow Monitors

Test, compute, and record the calibration error of each stack flow monitor at least once within every 14 calendar day period during which at anytime emissions flow through the stack; or for monitors or monitoring systems on bypass stacks or ducts, at least once within every 14 calendar day period during which at anytime emissions flow through the bypass stack or duct. Introduce a zero reference value to the transducer or transmitter. Record flow monitor output from the data acquisition and handling systems before and after any adjustments. Calculate the calibration error using the following equation:

$$CE = \frac{|R - A|}{S} \times 100 \qquad \text{(Eq. C-2)}$$

Where:

CE = Percentage calibration error based on the span range

R = Zero reference value introduced into the. transducer or transmitter.

A = Actual monitoring system response.

S = Span range of the flow monitor.

c. Interference Check for Stack Flow Monitors

Perform the daily flow monitor interference checks specified in Paragraph B.1.c.i. of this Attachment at least once per operating day (when the unit(s) operate for any part of the day).

i. Design Requirements for Flow Monitor Interference Checks

Design and equip each flow monitor with a means to ensure that the moisture expected to occur at the monitoring location does not interfere with the proper functioning of the flow monitoring system. Design and equip each flow monitor with a means to detect, on at least a daily basis, pluggage of each sample line and sensing port, and malfunction of each resistance temperature detector (RTD), transceiver, or equivalent.

Design and equip each differential pressure flow monitor to provide (1) an automatic, periodic backpurging (simultaneously on both sides of the probe) or equivalent method of sufficient force and frequency to keep the probe and lines sufficiently free of obstructions on at least a daily basis to prevent sensing interference, and (2) a means to detecting leaks in the system at least on a quarterly basis (a manual check is acceptable).

Design and equip each thermal flow monitor with a means to ensure on at least a daily basis that the probe remains sufficiently clean to prevent velocity sensing interference.

Design and equip each ultrasonic flow monitor with a means to ensure on at least a daily basis that the transceivers remain sufficiently clean (for example, backpurging the system) to prevent velocity sensing interference.

d. Recalibration

Adjust the calibration, at a minimum, whenever the calibration error exceeds the limits of the applicable performance specification for the NO_x monitor, O_2 monitor or stack flow monitor to meet such specifications. Repeat the calibration error test procedure following the adjustment or repair to demonstrate that the corrective actions were effective. Document the adjustments made.

e. Out-of-Control Period – Calibration Test

An out-of-control period occurs when the calibration error of an NO_x concentration monitor exceeds 5.0 percent based upon the span range value, when the calibration error of an O_2 monitor exceeds 1.0 percent O_2, or when the calibration error of a flow monitor exceeds 6.0 percent based upon the span range value, which is twice the applicable specification. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour of completion following an effective recalibration. Whenever the failed calibration, corrective action, and effective recalibration occur within the same hour, the hour is not out-of-control if 2 or more valid readings are obtained during that hour as required by Chapter 2, Subdivision B, Paragraph 5.

An out-of-control period also occurs whenever interference of a flow monitor is identified. The out-of-control period begins with the hour of the failed interference check and ends with the hour of completion of an interference check that is passed.

f. Data Recording

Record and tabulate all calibration error test data according to the month, day, clock-hour, and magnitude in ppm, DSCFH, and percent volume. Program monitors that automatically adjust data to the calibrated corrected calibration values (for example, microprocessor control) to record either: (1) the unadjusted concentration or flow rate measured in the calibration error test prior to resetting the calibration, or (2) the magnitude of any adjustment. Record the following applicable flow monitor interference check data: (1) sample line/sensing port pluggage, and (2) malfunction of each RTD, transceiver, or equivalent.

2. Semi-annual Assessments

a. For each CEMS, perform the following assessments once semi-annually thereafter, as specified below for the type of test. These semi-annual assessments shall be completed within six months of the end of the calendar quarter in which the CEMS was last tested for certification purposes (initial and recertification) or within three months of the end of the calendar quarter in which the District sent notice of a provisional approval for a CEMS, whichever is later. Thereafter, the semi-annual tests shall be completed within six months of the end of the calendar quarter in which the CEMS was last tested. For CEMS on bypass stacks/ducts, the assessments shall be performed once every two successive operating quarters in which the bypass stacks/ducts were operated. These tests shall be performed after the calendar quarter in which the CEMS was last tested as part of the CEMS certification, as specified below for the type of test.

Relative accuracy tests may be performed on an annual basis rather than on a semi-annual basis if the relative accuracies during the previous audit for the NO_X pollutant concentration monitor, flow monitoring system, and NOx emission rate measurement system are 7.5 percent or less.

b. For CEMS on any stack or duct through which no emissions have passed in two or more successive quarters, the semi-annual assessments must be performed within 14 unit operating days after emissions pass through the stack/duct.

c. The due date for a semi-annual or annual assessment of a major source may be postponed to within 14 unit operating days from the first re-firing of the major source if the major source is physically incapable of being operated and all of the following are met:

i. All fuel feed lines to the major source are either disconnected or opened and either flanges or equivalent sealing devices are placed at both ends of the disconnected or opened lines, and

ii. The fuel meter(s) for the disconnected or opened fuel feed lines are maintained and operated and associated fuel records showing no fuel flow are maintained on site.

This paragraph applies separately for each unrelated, independent event. For any hour that fuel flow records are not available to verify no fuel flow, NOx emissions shall be calculated using the maximum valid hourly emissions from the last 30 days of operation.

Prior to re-starting operation of the major source, the Facility Permit Holder shall: (1) provide written notification to the District no later than 72 hours prior to starting up the source, (2) start the CEMS no later than 24 hours prior to the start-up of the major source, and (3) conduct and pass a Cylinder Gas Analysis (CGA) prior to the start-up of the major source. The emissions data from the CEMS after the re-start of operations is considered valid only if the Facility Permit Holder passes the CGA test. Otherwise, for a non-passing CGA, the CEMS data is considered invalid until the semi-annual or annual assessment is performed and passed. As such, NOx emissions shall be calculated using the maximum valid hourly emissions from the last 30 days of operation commencing with the hour of start up and continuing through the hour prior to performing and passing the semi-annual or annual assessment.

d. An electrical generating facility that either only operates under a California Independent System Operator (Cal ISO) contract or is owned and operated by a municipality may postpone the due date for a semi-annual or annual assessment of a major source to the next calendar quarter provided that the facility shows:

i. The semi-annual or annual assessment was scheduled to be performed during the first 45 days of the calendar quarter in which the assessment was due;

ii. The assessment was not completed due to lack of adequate operational time; and

iii. A CGA was conducted and passed within the calendar quarter when the assessment was due.

e. Relative Accuracy Test Audit

Perform relative accuracy test audits and bias tests semi-annually and no less than 3 months apart for each NO_X pollutant concentration monitor, stack gas volumetric flow rate measurement systems, and the NO_X mass emission rate measurement system in accordance with Chapter 2, Subdivision B, Paragraphs 10, 11, 12, and 18. The relative accuracy of the pollutant concentration monitor and the mass emission rate measurement system shall be less than or equal to 20.0 percent, and the relative accuracy of the stack gas volumetric flow rate measurement system shall be less than or equal to 15.0 percent. For monitors on bypass stacks/ducts, perform relative accuracy test audits once every two successive bypass operating quarters in accordance with Chapter 2, Subdivision B, Paragraphs 10, 11, 12, and 18.

f. Out-of-Control Period – Relative Accuracy Test Audit

An out-of-control period occurs under any of the following conditions: (1) The relative accuracy of an NO_X pollutant concentration monitor or the NO_X emission rate measurement system exceeds 20.0 percent; (2) the relative accuracy of the flow rate monitor exceeds 15.0 percent; or (3) failure to conduct a relative accuracy test audit by the due date for a semi-annual assessment. The out-of-control period begins with the hour of completion of the failed relative accuracy test audit and ends with the hour of completion of a satisfactory relative accuracy test audit.

g. Out-of-Control Period – BIAS Test

An out-of-control period occurs if all the following conditions are met:

i. Failure of a bias test as specified in Attachment B of this Appendix;

ii. The CEMS is biased low relative to the reference method (i.e. Bias Adjustment Factor (BAF), as determined in Attachment B of this Appendix, is greater than 1); and

iii. The Facility Permit holder does not apply the BAF to the CEMS data.

The out-of-control period begins with the hour of completion of the failed bias test audit and ends with the hour of completion of a satisfactory bias test.

h. Alternative Relative Accuracy Test Audit

i. The Facility Permit holder of a major source, that has received written approval from the Executive Officer as an intermittently operated source, may postpone the due date for a semi-annual assessment to the end of the next calendar quarter if the Facility Permit holder:

I. operated the source no more than 240 cumulative operating hours and no more than 72 consecutive hours during the calendar quarter when a semi-annual assessment is due; and

II. conducted a relative accuracy test audit on the CEMS serving the source during the previous four calendar quarters and meeting the accuracy criteria as set forth under Subparagraph B.2.e.; and

III. conducted an alterative relative accuracy test audit on the CEMS serving the source during the calendar quarter when a semi-annual assessment is due and meeting the criteria specified under Clause B.2.h.iii.

If any of the requirements under Subclauses B.2.h.i.I, II and III is not met and the source did not have passing RATA during the calendar quarter when the semi-annual assessment is due, emissions from the source shall be determined pursuant to the Missing Data Procedures as specified under Rule 2012, Appendix A, Chapter 2, Subdivision E after the semi-annual assessment due date until the hour of completion of a satisfactory relative accuracy test audit.

ii. The Facility Permit holder may submit a written request to designate a major source as an intermittently operated source provided the Facility Permit holder demonstrates that:

I. During any calendar quarter within the previous two compliance years, the source was operated no more than

240 cumulative operating hours and no more than 72 consecutive hours; or

II. During any calendar quarter within the next two compliance years, the source will be operated no more than 240 cumulative operating hours and no more than 72 consecutive hours.

iii. An alternative relative accuracy shall consist of a Cylinder Gas Analysis (CGA) method as defined under 40 CFR, Part 60, Appendix F, combined with a flow accuracy verification. For sources equipped with stack flow monitors, the flow accuracy shall be verified by calibrating the transducers and transmitters installed on the stack flow monitors using procedures under Paragraph B.3 of this attachment. For sources equipped with fuel flow meters and no stack flow monitors, the flow accuracy shall be verified by calibrating the fuel flow meters either in-line or offline in accordance with the procedures outlined in 40CFR Part 75, Appendix D. Passing flow accuracy verification results that were obtained within the past 4 quarters may be used in lieu of performing a flow accuracy verification during the calendar quarter when a semi-annual assessment is due. The calculated accuracy for the analyzer responses for NO_x and O_2 concentration shall be within 15 percent or 1 ppm, whichever is greater, as determined by the CGA method as defined under 40 CFR, Part 60, Appendix F. Successive alternative relative accuracy test audits shall be performed no less than 45 days apart.

3. Calibration of Transducers and Transmitters on Stack Flow Monitors

All transducers and transmitters installed on stack flow monitors must be calibrated every two operating calendar quarters, in which an operating calendar quarter is any calendar quarter during which at anytime emissions flow through the stack. Calibration must be done in accordance with Executive Officer approved calibration procedures that employ materials and equipment that are NIST traceable.

When a calibration produces for a transducer and transmitter a percentage accuracy of greater than ± 1%, the Facility Permit holder shall calibrate the transducer and transmitter every calendar operating quarter until a subsequent calibration which shows a percentage accuracy of less than ± 1% is achieved. An out-of-control period occurs when the percentage accuracy exceeds ±2%. If an out-of-control period occurs, the Facility Permit holder shall take corrective measures to obtain a percentage accuracy of less than ±2% prior to performing the next RATA. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour of completion of following an effective recalibration. Whenever the failed calibration, corrective action, and effective recalibration occur within the same hour, the hour is not out-of-control if two or more valid data readings are obtained during that hour as required by Chapter 2, Subdivision B, Paragraph 5, Subparagraph a.

RULE 2012 PROTOCOL-ATTACHMENT D

EQUIPMENT TUNING PROCEDURES

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EQUIPMENT TUNING PROCEDURES

A. PROCEDURES

Nothing in this Equipment Tuning Procedure shall be construed to require any act or omission that would result in unsafe conditions or would be in violation of any regulation or requirement established by Factory Mutual, Industrial Risk Insurers, National Fire Prevention Association, the California Department of Industrial Relations (Occupational Safety and Health Division), the Federal Occupational Safety and Health Administration, or other relevant regulations and requirements.

1. Operate the unit at the firing rate most typical of normal operation. If the unit experiences significant load variations during normal operation, operate it at its average firing rate.

2. At this firing rate, record stack-gas temperature, oxygen concentration, and CO concentration (for gaseous fuels) or smoke-spot number 2 (for liquid fuels), and observe flame conditions after unit operation stabilizes at the firing rate selected. If the excess oxygen in the stack gas is at the lower end of the range of typical minimum values, and if CO emissions are low and there is no smoke, the unit is probably operating at near optimum efficiency at this particular firing rate.

3. Increase combustion air flow to the furnace until stack-gas oxygen levels increase by one to two percent over the level measured in Step 2. As in Step 2, record the stack-gas temperature, CO concentration (for gaseous fuels) or smoke-spot number (for liquid fuels), and observe flame conditions for these higher oxygen levels after boiler operation stabilizes.

4. Decrease combustion air flow until the stack gas oxygen concentration is at the level measure in Step 2. From this level, gradually reduce the combustion air flow in small increments. After each increments, record the stack-gas temperature, oxygen concentration, CO concentration (for gaseous fuels), and smoke-spot number (for liquid fuels). Also observe the flame and record any changes in its condition.

5. Continue to reduce combustion air flow stepwise, until one of these limits is reached:

    a. Unacceptable flame conditions, such as flame impingement on furnace walls or burner parts, excessive flame carryover, or flame instability; or

b. Stack gas CO concentrations greater than 400 ppm; or

c. Smoking at the stack; or

d. Equipment-related limitations, such as low windbox/furnace pressure differential, built in air-flow limits, etc.

6. Develop an O2/CO curve (for gaseous fuels) or O2/smoke curve (for liquid fuels) using the excess oxygen and CO or smoke-spot number data obtained at each combustion air flow setting.

7. From the curves prepared in Step 6, find the stack-gas oxygen levels where the CO emissions or smoke-spot number equal the following values:

Fuel	Measurement	Value
Gaseous	CO emissions	400 ppm
#1 and #2 oils	smoke-spot number	number 1
#4 oil	smoke-spot number	number 2
#5 oil	smoke-spot number	number 3
Other oils	smoke-spot number	number 4

The above conditions are referred to as the CO or smoke thresholds, or as the minimum excess oxygen level.

Compare this minimum value of excess oxygen to the expected value provided by the combustion unit manufacturer. If the minimum level found is substantially higher than the value provided by the combustion unit manufacturer, burner adjustments can probably be made to improve fuel and air mixing, thereby allowing operation with less air.

8. Add 0.5 to 2.0 percent of the minimum excess oxygen level found in Step 7 and reset burner controls to operate automatically at this higher stack-gas oxygen level. This margin above the minimum oxygen level accounts for fuel variations, variations in atmospheric conditions, load changes, and nonrepeatability or play in automatic controls.

9. If the load of the combustion unit varies significantly during normal operation, repeat Steps 1-8 for firing rates that represent the upper and lower limits of the range of the load. Because control adjustments at one firing rate may affect conditions at other firing rates, it may not be possible to establish the optimum

excess oxygen level at all firing rates. If this is the case, choose the burner control settings that give best performance over the range of firing rates. If one firing rate predominates, settings should optimize conditions at that rate.

10. Verify that the new settings can accommodate the sudden load changes that may occur in daily operation without adverse effects. Do this by increasing and decreasing load rapidly while observing the flame and stack. If any of the conditions in Step 5 result, reset the combustion controls to provide a slightly higher level of excess oxygen at the affected firing rates. Next, verify these new recorded at steady-rate operating conditions for future reference.

RULE 2012 PROTOCOL- ATTACHMENT E

LIST OF ACRONYMS AND ABBREVIATIONS

LIST OF ACRONYMS AND ABBREVIATIONS

APEP	Annual Permit Emission Program
API	American Petroleum Institute
ASTM	American Society for Testing & Materials
BACT	Best Available Control Technology
bhp	Brake Horsepower
bpd	Barrels per Day
Btu	British Thermal Unit
CEMS	Continuous Emission Monitoring System
CPMS	Continuous Process Monitoring System
CPU	Central Processing Unit
CSCACS	Central Station Compliance Advisory Computer System
DAS	Data Acquisition System
DM	District Method
dscfh	Dry Standard Cubic Feet per Hour
FCCU	Fluid Catalytic Cracking Unit
F_d	Dry F Factor
FGR	Flue Gas Recirculation
gpm	Gallons per Minute
HRG	Hardware Requirement Guideline
ICE	Internal Combustion Engine
ID	Inside Diameter
ISO	International Standards Organization
lb mole	Pound mole
LNB	Low NO_x Burner
MRR	Monitoring, Reporting and Recordkeeping
NO_x	Oxides of Nitrogen
NIST	National Institute for Standards and Testing
NSCR	Non-Selective Catalytic Reduction
O_2	Oxygen
ppmv	Parts per Million Volume
ppmw	Parts per Million by Weight

RAA	Relative Accuracy Audit
RATA	Relative Accuracy Test Audit
RECLAIM	Regional Clean Air Incentives Market
RM	Reference Method
RTC	RECLAIM Trading Credits
RTCC	Real Time Calendar/Clock
RTU	Remote Terminal Unit
scfh	Standard Cubic Feet per Hour
scfm	Standard Cubic Feet per Minute
SCR	Selective Catalytic Reduction
SDD	Software Design Description
SNCR	Selective Non-Catalytic Reduction
SO_X	Oxides of Sulfur
SRG	Software/Hardware Requirement Guideline
swi	Steam Water Injection
tpd	Tons per day
tpy	Tons per year
WAN	Wide Area Network

3/17/17

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

RULE 2012 PROTOCOL-
ATTACHMENT F

DEFINITIONS

DEFINITIONS

(1) AFTERBURNERS, also called VAPOR INCINERATORS, are air pollution control devices in which combustion converts the combustible materials in gaseous effluents to carbon dioxide and water.

(2) ANNUAL PERMIT EMISSIONS PROGRAM (APEP) is the annual facility permit compliance reporting, review, and fee reporting program.

(3) BOILER should generally be considered as any combustion equipment used to produce steam, including a carbon monoxide boiler. This would generally not include a process heater that transfers heat from combustion gases to process streams, a waste heat recovery boiler that is used to recover sensible heat from the exhaust of process equipment such as a combustion turbine, or a recovery furnace that is used to recover process chemicals. Boilers used primarily for residential space and/or water heating are not affected by this section.

(4) BURN means to combust any gaseous fuel, whether for useful heat or by incineration without recovery, except for flaring or emergency vent gases.

(5) BYPASS OPERATING QUARTER means each calendar quarter that emissions pass through the bypass stack or duct.

(6) CALCINER is a rotary kiln where calcination reaction is carried out between 1315 ^{o}C to 1480 ^{o}C.

(7) CEMENT KILN is a device for the calcining and clinkering of limestone, clay and other raw materials, and recycle dust in the dry-process manufacture of cement.

(8) CONTINUOUS EMISSIONS MONITORING SYSTEM (CEMS) is the total equipment required for the determination of concentrations of air contaminants and diluent gases in a source effluent as well as mass emission rate. The system consists of the following three major subsystems:

(A) SAMPLING INTERFACE is that portion of the monitoring system that performs one or more of the following operations: extraction, physical/chemical separation, transportation, and conditioning of a sample of the source effluent or protection of the analyzer from the hostile aspects of the sample or source environment.

(B) ANALYZERS

(i) AIR CONTAMINANT ANALYZER is that portion of the monitoring system that senses the air contaminant and generates a signal output which is a function of the concentration of that contaminant.

(ii) DILUENT ANALYZER is that portion of the monitoring system that senses the concentration of oxygen or carbon dioxide or other diluent gas as applicable, and generates a signal output which is a function of a concentration of that diluent gas.

(C) DATA RECORDER is that portion of the monitoring system that provides a permanent record of the output signals in terms of concentration units, and includes additional equipment such as a computer required to convert the original recorded value to any value required for reporting.

(9) CONTINUOUS PROCESS MONITORING SYSTEM is the total equipment required for the measurement and collection of process variables (e.g., fuel usage rate, oxygen content of stack gas, or process weight). Such CPMS data shall be used in conjunction with the appropriate emission rate to determine NOx emissions.

(10) CONTINUOUSLY MEASURE means to measure at least once every 15 minutes except during period of routine maintenance and calibration, as specified in 40CFR Part 60.13(e)(2).

(11) DAILY means a calendar day starting at 12 midnight and continuing through to the following 12 midnight hour.

(12) DIRECT MONITORING DEVICE is a device that directly measures the variables specified by the Executive Officer to be necessary to determine mass emissions of a RECLAIM pollutant and which meets all the standards of performance for CEMS set forth in the protocols for NOx and SOx.

(13) DRYER is equipment that removes substances by heating or other processes.

(14) ELECTRONICALLY TRANSMITTING means transmitting measured data without human alteration between the point/source of measurement and transmission.

(15) EMISSION FACTOR is the value specified in Tables 1 (NOx) or 2 (SOx) of Rule 2002-Baselines and Rates of Reduction for NOx and SOx.

(16) EMISSION RATE (ER) - is a value expressed in terms of NOx mass emissions per unit of heat input, and derived using the methodology specified in the "Protocol for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions" Chapter .

(17) EXISTING EQUIPMENT is any equipment which can emit NOx at a NOx RECLAIM facility, for which on or before (Rule Adoption date) has:

(A) A valid permit to construct or permit to operate pursuant to Rule 201 and/or Rule 203 has been issued; or

(B) An application for a permit to construct or permit to operate has been deemed complete by the Executive Officer; or

(C) An equipment which is exempt from permit per Rule 219 and is operating on or before (Rule Adoption date).

(18) F_d FACTOR is the dry F factor for each fuel, the ratio of the dry gas volume of the products of combustion to the heat content of the fuel (dscf/10^6 Btu). F factors are available in 40 CFR Part 60, Appendix A, Method 19.

(19) FLUID CATALYTIC CRACKING UNIT (FCCU) breaks down heavy petroleum products into lighter products using heat in the presence of finely divided catalyst maintained in a fluidized state by the oil vapors. The fluid catalyst is continuously circulated between the reactor and the regenerator, using air, oil vapor, and steam as the conveying media.

(20) FURNACE is an enclosure in which energy in a nonthermal form is converted to heat.

(21) GAS FLARE is a combustion equipment used to prevent unsafe operating pressures in process units during shut downs and start-ups and to handle miscellaneous hydrocarbon leaks and process upsets.

(22) GAS TURBINES are turbines that use gas as the working fluid. It is principally used to propel jet aircraft. Their stationary uses include electric power generation (usually for peak-load demands), end-of-line voltage booster service for long distance transmission lines, and for pumping natural gas through long distance pipelines. Gas turbines are used in combined (cogeneration) and simple-cycle arrangements.

(23) GASEOUS FUELS include, but are not limited to, any natural, process, synthetic, landfill, sewage digester, or waste gases with a gross heating value of 300 Btu per cubic foot or higher, at standard conditions.

(24) HEAT VALUE is the heat generated when one lb. of combustible is completely burned.

(25) HEATER is any combustion equipment fired with liquid and/or gaseous fuel and which transfers heat from combustion gases to water or process streams.

(26) HIGH HEAT VALUE is determined experimentally by colorimeters in which the products of combustion are cooled to the initial temperature and the heat absorbed by the cooling media is measured.

(27) HOT STAND-BY is the period of operation when the flow or emission concentration are so low they can not be measured in a representative manner.

(28) INCINERATOR is equipment that consumes substances by burning.

(29) INTERNAL COMBUSTION ENGINE is any spark or compression-ignited internal combustion engine, not including engines used for self-propulsion.

(30) LIQUID FUELS include, but are not limited to, any petroleum distillates or fuels in liquid form derived from fossil materials or agricultural products for the purpose of creating useful heat.

(31) MASS EMISSION OF NOx in lbs/hr is the measured emission rates of nitrogen oxides.

(32) MAXIMUM RATED CAPACITY means maximum design heat input in Btu per hour at the higher heating value of the fuels.

(33) MODEM converts digital signals into audio tones to be transmitted over telephone lines and also convert audio tones from the lines to digital signals for machine use.

(34) MONTHLY FUEL USE REPORTS could be sufficed by the monthly gas bill or the difference between the end and the beginning of the calendar month's fuel meter readings.

(35) NINETIETH (90TH) PERCENTILE means a value that would divide an ordered set of increasing values so that at least 90 percent are less than or equal to the value and at least 10 percent are greater than or equal to the value.

(36) OVEN is a chamber or enclosed compartment equipped to heat objects.

(37) PEAKING UNIT means a turbine used intermittently to produce energy on a demand basis and does not operate more than 1300 hours per year.

(38) PORTABLE EQUIPMENT is an equipment which is not attached to a foundation and is not operated at a single facility for more than 90 days in a year and is not a replacement equipment for a specific application which lasts or is intended to last for more than one year.

(39) PROCESS HEATER means any combustion equipment fired with liquid and/or gaseous fuel and which transfers heat from combustion gases to process streams.

(40) PROCESS WEIGHT means the total weight of all materials introduced into any specific process which may discharge contaminants into the atmosphere. Solid fuels charged shall be considered as part of the process weight, but liquid gaseous fuels and air shall not.

(41) RATED BRAKE HORSEPOWER (bhp) is the maximum rating specified by the manufacturer and listed on the nameplate of that equipment. If not available, then the rated brake horsepower of an internal combustion engine can be calculated by multiplying the maximum fuel usage per unit time, heating value of fuel, equipment

efficiency provided by the manufacturer, and the conversion factor (one brake horsepower = 2,545 Btu).

(42) RATED HEAT INPUT CAPACITY is the heat input capacity specified on the nameplate of the combustion unit. If the combustion unit has been altered or modified such that its maximum heat input is different than the heat input capacity specified on the nameplate, the new maximum heat input shall be considered as the rated heat input capacity.

(43) RECLAIM FACILITY is a facility that has been listed as a participant in the Regional Clean Air Incentives Market (RECLAIM) program.

(44) REMOTE TERMINAL UNIT (RTU) is a data collection and transmitting device used to transmit data and calculated results to the District Central Station Computer.

(45) RENTAL EQUIPMENT is equipment which is rented or leased for operation by someone other than the owner of the equipment.

(46) SHUTDOWN is that period of time during which the equipment is allowed to cool from a normal operating temperature range to a cold or ambient temperature.

(47) SOLID FUELS include, but are not limited to, any solid organic material used as fuel for the purpose of creating useful heat.

(48) STANDARD GAS CONDITIONS are defined as one atmosphere of pressure and a temperature of 68 ^{O}F or 60 ^{O}F, provided that one of these temperatures is used throughout the facility.

(49) START-UP is that period of time during which the equipment is heated to operating temperature from a cold or ambient temperature.

(50) SULFURIC ACID PRODUCTION UNIT means any facility producing sulfuric acid by the contact process by burning elemental sulfur, alkylation acid, hydrogen sulfide, organic sulfides and mercaptans or acid sludge, but does not include facilities where conversion to sulfuric acid as utilized primarily as a means of preventing emissions to the atmosphere of sulfur dioxide or other sulfur compounds.

(51) TAIL GAS UNIT is a SOx control equipment associated with refinery sulfur recovery plant.

(52) TEST CELLS are devices used to test the performance of engines such as internal combustion engine and jet engines.

(53) TIMESHARING OF MONITOR means the use of a common monitor for several sources of emissions.

(54) TURBINES are machines that convert energy stored in a fluid into mechanical energy by channeling the fluid through a system of stationary and moving vanes.

(55) UNIT OPERATING DAY means each calendar day that emissions pass through the stack or duct.

(56) UNIVERSE OF SOURCES FOR NOx is a list of RECLAIM facilities that emit NOx.

(57) UNIVERSE OF SOURCES FOR SOx is a list of RECLAIM facilities that emit SOx.

(58) AP 42 is a publication published by Environmental Protection Agency (EPA) which is a compilation of air pollution emission rates used to determine mass emission.

(59) ASTM METHOD D1945-81 Method for Analysis of natural gas by gas chromatography.

(60) ASTM METHOD 2622-82 Test Method for sulfur in petroleum products (Xray Spectrographic method)

(61) ASTM METHOD 3588-91 method for calculating colorific value and specific gravity (relative density) of gaseous fuels.

(62) ASTM METHOD 4294-90 test method for sulfur in petroleum products by non-dispersive Xray fluorescence spectrometry.

(63) ASTM METHOD 4891-84 test method for heating value of gases in natural gas range by stoichiometric combustion.

(64) DISTRICT METHOD 2.1 measures gas flow rate through stacks greater than 12 inch in diameter.

(65) DISTRICT METHOD 7.1 colorimetric determination of nitrogen oxides except nitrous oxide emissions from stationary sources by using the phenoldisulfonic acid (pds) procedure or ion chromatograph procedures. Its range is 2 to 400 milligrams NOx (as NO_2 per DSCM).

(66) DISTRICT METHOD 100.1 is an instrumental method for measuring gaseous emissions of nitrogen oxides, sulfur dioxide, carbon monoxide, carbon dioxide, and oxygen.

(67) DISTRICT METHOD 307-91 laboratory procedure for analyzing total reduced sulfur compounds and SO_2.

(68) EPA METHOD 19 is the method of determining sulfur dioxide removal efficiency and particulate, sulfur dioxide and nitrogen oxides emission rates from electric utility steam generators.

(69) EPA METHOD 450/3-78-117 air pollutant emission rate for Military and Civil Aircraft.

RULE 2012 PROTOCOL- ATTACHMENT G

SUPPLEMENTAL AND ALTERNATIVE CEMS PERFORMANCE REQUIREMENTS FOR LOW NOx CONCENTRATIONS

ATTACHMENT G

SUPPLEMENTAL AND ALTERNATIVE CEMS PERFORMANCE REQUIREMENTS FOR LOW NOx CONCENTRATIONS

Abbreviations used in this Attachment are:
- ✓ Low Level Spike Recovery/Bias Factor Determination (LLSR/BFD)
- ✓ High Level Spike Recovery/Bias Factor Determination (HLSR/BFD)
- ✓ Low Level RATA/Bias Factor Determination (LLR/BFD)
- ✓ Low Level Calibration Error (LLCE)
- ✓ Relative Accuracy Test Audit (RATA)
- ✓ Relative Accuracy (RA)
- ✓ Full Scale Span (FSS)
- ✓ National Institute of Standards Traceability (NIST)

A. Applicability of Supplemental and Alternative Performance Requirements

The Facility Permit holder electing to use (B)(8)(d)(ii), in Chapter 2 of Rule 2012, Appendix A to measure NO_x concentrations that fall below 10 percent of the lowest vendor guaranteed full scale span range, shall satisfy the performance requirements as specified in Table G-1 listed below.

TABLE G-1
Alternative Performance Requirement(s)

CEMS RECLAIM Certified per NOx Protocol, Appendix A	**Performance Requirements**			
Yes or No	LLSR/BFD	HLSR/BFD	LLR/BFD	LLCE
Yes	**x**		+	**x**
No	**x**	**x**	+	**x**

1. + (plus) denotes an additional performance requirement that shall be conducted if the mandatory performance requirement(s) cannot be met.

2. If the concentration of the CEMS is such that the specifications for the low level spike recovery/bias factor determination cannot be met, the Facility Permit holder shall conduct a low level RATA/bias factor determination.

3. The provisions of Table G-1 do not apply to (B)(8)(c) or (B)(8)(d)(i), in Chapter 2.

B. Test Definitions, Performance Specifications and Test Procedures

This section explains in detail how each performance requirement is to be conducted.

Low Level Calibration Error

The low level calibration error test is defined as challenging the CEMS (from probe to monitor) with certified calibration gases (NO in N2) at three levels in the 0-20 percent full scale span range. Since stable or certifiable cylinder gas standards (e.g. Protocol 1 or NIST traceable) may not be available at the concentrations required for this test, gas dilution systems may be used, with District approval, if they are used according to either District or EPA protocols for the verification of gas dilution systems in the field. The CEMS high level calibration gas may be diluted for the purpose of conducting the low level calibration error test.

1. Performance Specifications

   Introduce pollutant concentrations at approximately the 20 percent, 10 percent, and 5 percent of full scale span levels through the normal CEMS calibration system. No low level calibration error shall exceed 2.5 percent of full scale span.

2. Testing Procedures

   a. Perform a standard zero/span check; if zero or span check exceeds 2.5 percent full scale span, adjust monitor and redo zero/span check.

   b. After zero/span check allow the CEMS to sample stack gas for at least 15 minutes.

   c. Introduce any of the low level calibration error standards through the CEMS calibration system.

   d. Read the CEMS response to the calibration gas starting no later than three system response times after introducing the calibration gas; the CEMS response shall be averaged for at least three response times and for no longer than six response times.

   e. After the low level calibration error check allow the CEMS to sample stack gas for at least 15 minutes.

   f. Repeat steps c through e until all three low level calibration error checks are complete.

   g. Conduct post test calibration and zero checks.

Spike Recovery and Bias Factor Determinations

Spiking is defined as introducing know concentrations of the pollutant of interest (gas standard to contain a mixture of NO and NO2 is representative of the ratio of NO and NO2 in stack gas) and an appropriate non-reactive, non-condensable and non-soluble tracer gas from a single cylinder (Protocol 1 or NIST traceable to 2 percent analytical accuracy if no Protocol 1 is available) near the probe and upstream of any sample conditioning systems, at a flow rate not to exceed 10 percent of the total sample gas flow rate. The purpose of the 10 percent limitation is to ensure that the gas matrix (water, CO2, particulates, interferences) is essentially the same as the stack gas alone. The tracer gas is monitored in real time and the ratio of the monitored concentration to the certified concentration in the cylinder is the dilution factor. The expected pollutant concentration (dilution factor times the certified pollutant concentration in the cylinder) is compared to the monitored pollutant concentration.

High Level Spike Recovery/Bias Factor Determination

The high level spike recovery/bias factor determination is used when it is technologically not possible to certify the CEMS per the standard RECLAIM requirements. The spiking facility/interface shall be a permanently installed part of the CEMS sample acquisition system and accessible to District staff as well as the Facility Permit holder.

1. Performance Specifications

   The CEMS shall demonstrate a RA </= 20 percent, where the spike value is used in place of the reference method in the normal RA calculation, as described below. The bias factor, if applicable, shall also be determined according to Attachment B.

2. Testing Procedures

   a. Spike the sample to the CEMS with a calibration standard containing the pollutant of interest and CO or other non-soluble, non-reacting alternative tracer gas (alternative tracer gas) at a flow rate not to exceed 10 percent of the CEMS sampling flow rate and of such concentrations as to produce an expected 40-80 percent of full scale span for the pollutant of interest and a quantifiable concentration of CO (or alternative tracer gas) that is at least a factor of 10 higher than expected in the unspiked stack gas. The calibration standards for both pollutant of interest and CO (or alternative tracer gas) must meet RECLAIM requirements specified in Attachment A.

   b. Monitor the CO (or alternative tracer gas) using an appropriate continuous (or semi-continuous if necessary) monitor meeting the requirements of Method 100.1 and all data falling within the 10-95 percent full scale span, and preferably within 30-70 percent full scale span.

   c. Alternate spiked sample gas and unspiked sample gas for a total of nine runs of spiked sample gas and ten runs of unspiked sample gas. Sampling times should be sufficiently long to mitigate response time and averaging effects.

d. For each run, the average CEMS reading must be between 40 percent full scale span and 80 percent full scale span. If not, adjust spiking as necessary and continue runs; but expected spike must represent at least 50 percent of the total pollutant value read by the CEMS.

e. Calculate the spike recovery for both the pollutant and the CO (or alternative tracer gas) for each run by first averaging the pre- and post-spike values for each run and subtracting that value from the spiked value to yield nine values for recovered spikes.

f. Using the CO (or alternative tracer gas) spike recovery values for each run and the certified CO (or alternative tracer gas) concentration, calculate the dilution ratio for each run. Multiply the certified pollutant concentration by the dilution factor for each run to determine the expected diluted pollutant concentrations. Using the expected diluted concentrations as the "reference method" value calculate the Relative Accuracy as specified in Appendix A. The RA shall be </= 20 percent. Determine the bias factor, if applicable, according to Attachment B.

Low Level Spike Recovery/Bias Factor Determination

The low level spike recovery/bias factor determination is used to determine if a significant bias exists at concentrations near the 10 percent full scale span level. The spiking facility/interface shall be a permanently installed part of the CEMS sample acquisition system and accessible to District staff as well as the Facility Permit holder.

1. Performance Specifications

There are no pass/fail criteria with respect to the magnitude of the percent relative accuracy. There are performance criteria for the range of concentration on the CEMS and the extent to which the spike must be greater than the background pollutant level.

2. Testing Procedures

a. Spike the sample to the CEMS with a calibration standard containing the pollutant of interest and CO or other non-soluble, non-reacting alternative tracer gas (alternative tracer gas) at a flow rate not to exceed 10 percent of the CEMS sampling flow rate and of such concentrations as to produce an expected 10-25 percent of full scale span for the pollutant of interest and a quantifiable concentration of CO (or alternative tracer gas) that is at least a factor of 10 higher than expected in the unspiked stack gas. The calibration standards for both pollutant of interest and CO (or alternative tracer gas) must meet RECLAIM requirements specified in Appendix A.

b. Monitor the CO (or alternative tracer gas) using an appropriate continuous (or semi-continuous if necessary) monitor meeting the requirements of Method 100.1 and all data falling within the 10-95 percent full scale span, and preferably within 30-70 percent full scale span.

c. Alternate spiked sample gas and unspiked sample gas for a total of nine runs of spiked sample gas and ten runs of unspiked sample gas. Sampling times should be sufficiently long to mitigate response time and averaging effects.

d. For each run, the average CEMS reading must be below 25 percent full scale span and > 10 percent full scale span. If not, adjust spiking as necessary and continue runs; but expected spike must represent at least 50 percent of the total pollutant value read by the CEMS.

e. Calculate the spike recovery for both the pollutant and the CO (or alternative tracer gas) for each run by first averaging the pre- and post-spike values for each run and subtracting that value from the spiked value to yield nine values for recovered spikes.

f. Using the CO (or alternative tracer gas) spike recovery values for each run and the certified CO (or alternative tracer gas) concentration, .calculate the dilution ratio for each run. Multiply the certified pollutant concentration by the dilution factor for each run to determine the expected diluted pollutant concentrations. Using the expected diluted concentrations as the "reference method" value calculate the Relative Accuracy as specified in Appendix A. If the average difference is less than the confidence coefficient then no low level bias factor is applied. If the average difference is greater than the confidence coefficient and the average expected spike is less than the average CEMS measured spike, then no low level bias factor is applied. If the average difference is greater than the confidence coefficient and the average expected spike is greater than the average

CEMS measured spike, then a low level bias factor equal to the absolute value of the average difference is added to data reported at or below the 10 percent of full scale span.

Low Level RATA/Bias Factor Determination using Enhanced Reference Method 6.1

A low level RATA/bias factor determination is designed to determine if there exists a statistically significant bias at low level concentrations. It consists of nine test runs that measure the stack concentration and the CEMS concentration concurrently.

1. Performance Specifications

   There are no pass/fail criteria with respect to the magnitude of the percent relative accuracy. There are performance criteria for the special RATA with respect to the reference method and range of concentration on the CEMS.

2. Testing Procedures

   The reference method for the low level RATA/bias factor determination is Method 100.1

   a. Perform a minimum of nine runs of low level RATA for CEMS versus the reference method at actual levels (unspiked).

   b. The full scale span range for the reference method shall be such that all data falls with 10 - 95 percent of full scale span range.

   c. The reference method shall meet all Method 100.1 performance criteria.

   d. Calculate the average difference (d = CEMS - reference method, ppm) and confidence coefficient (cc = statistical calculated, ppm).

   e. If $d > 0$ then the bias = 0 ppm; if $d < 0$ and $|d| > cc$ then bias = d; if $d < 0$ and $|d| < cc$ then bias = 0 ppm.

C. Testing Frequency

For each CEMS, perform the aforementioned performance requirements once semiannually thereafter, as specified below for the type of test. These semiannual assessments shall be completed within six months of the end of the calendar quarter in which the CEMS was last tested for certification purposes (initial and recertification) or within three months of the end of the calendar quarter in which the District sent notice of a provisional approval for a CEMS, whichever is later. Thereafter, the semiannual tests shall be completed within six months of the end of the calendar quarter in which the CEMS was last tested. For CEMS on bypass stacks/ducts, the assessments shall be performed once every two successive operating quarters in which the bypass stacks/ducts were operated. These tests shall be performed after the calendar quarter in which the CEMS was last tested as part of the CEMS certification, as specified below for the type of test.

Relative accuracy tests may be performed on an annual basis rather than on a semiannual basis if the relative accuracies during the previous audit for the NO_X CEMS are 7.5 percent or less.

For CEMS on any stack or duct through which no emissions have passed in two or more successive quarters, the semiannual assessments must be performed within 14 operating days after emissions pass through the stack/duct.

(Adopted October 15, 1993)(Amended December 7, 1995)(Amended July 12, 1996)
(Amended February 14, 1997)(Amended May 11, 2001)(Amended June 4, 2004)

RULE 2015. BACKSTOP PROVISIONS

(a) Purpose

This rule specifies RECLAIM program auditing requirements and backstop provisions.

(b) Program Audits

(1) Annual Audits

The District will conduct an annual program audit. The annual audit will assess:

(A) emission reductions;

(B) per capita exposure to air pollution;

(C) facilities permanently ceasing operation of all sources;

(D) job impacts;

(E) average annual price of each type of RTC;

(F) availability of RTCs;

(G) toxic risk reductions;

(H) New Source Review permitting activity;

(I) compliance issues, including a list of facilities that were unable to reconcile emissions for that compliance year;

(J) emissions trends/seasonal fluctuations;

(K) emission control requirement impacts on stationary sources in the program compared to other stationary sources identified in the AQMP; and

(L) emissions associated with equipment breakdowns pursuant to paragraph (d)(3).

As part of the first three annual program audits, the Executive Officer will review the effectiveness of enforcement and protocols and recommend revisions to the protocols to achieve improved measurement and enforcement of RECLAIM emission reductions while minimizing administrative cost to the District and RECLAIM participants. The first audit will be presented to the Governing Board in a public hearing on or before January 1996, and by March of each subsequent year. Annual audits will be duly noticed to the public, including a statement that the list specified in subparagraph (b)(1)(I) is available. The audit report will be included henceforth in the District annual performance report to the California legislature.

(2) Mapping of Emissions

The Executive Officer will maintain, on an quarterly basis, a District-wide map indicating the most current sum of certified emissions. The information used to maintain the map will be obtained from the Quarterly Certification of Emissions and APEP required of Facility Permit holders pursuant to Rule 2004 - Requirements.

(3) Three-Year Audit

In 1997, at the close of the third year of trading, the District will conduct or commission a comprehensive audit to evaluate the performance of RECLAIM. This comprehensive audit will be presented to the Governing Board in a public hearing in the year 1998. The Governing Board will evaluate the performance of the program against the following criteria:

(A) RECLAIM has produced the emission reductions required;

(B) public health exposure to criteria air pollution has been significantly reduced, and public health exposure to toxics has not significantly increased as a result of RECLAIM;

(C) RECLAIM has not accelerated business shutdowns, job loss or shifts in the occupational structure of the region;

(D) the price of credits and the trading activity in each market has demonstrated adequate supply and demand;

(E) the emission monitoring, recordkeeping, and penalty provisions of RECLAIM have produced a strong compliance program and adequate deterrence of violations;

(F) RECLAIM is consistent with the provisions of the Federal Clean Air Act and the California Clean Air Act;

(G) the emission factors listed in Rule 2002 - Allocations for Oxides of Nitrogen (NO_X) and Oxides of Sulfur (SO_X), Tables 1 and 2 are consistent with and appropriate for any recent technology advancements;

(H) RECLAIM has not resulted in disproportionate impacts measured in terms of required emission reductions, on stationary sources in the program, compared to other stationary sources identified in the AQMP;

(I) whether RECLAIM should include a broad spectrum of sources, including mobile, area and stationary; and

(J) control technology has advanced as much as projected under the AQMP.

(4) Reports to the Governing Board

The Hearing Board will present a written report to the District Governing Board regarding any increases in annual Allocations issued pursuant to permit appeals. The Executive Officer will report to the District Governing Board, any recommendations necessary to maintain equivalency. These reports shall be incorporated into the Annual Program Audit Report prepared pursuant to Rule 2015(b)(1). The Executive Officer will propose to the Governing Board, any AQMP amendments necessary to make up for any shortfall resulting from adjustments to Allocations issued pursuant to Hearing Board appeals. In addition, the Executive Officer will propose to the Governing Board rule amendments to adjust RECLAIM Allocations if the Hearing Board issues Allocation adjustments that create a shortfall and are of a type which, if made by the Executive Officer during the issuance of initial Facility Permits, would have resulted in altered Allocations and rates of reduction for RECLAIM facilities.

(5) Program Amendment

The District reserves the right to amend the program pursuant to program evaluations. Nothing in District rules shall be construed to limit the District's authority to condition, limit, suspend or terminate any RTCs or the authorization to emit which a Facility Permit represents.

(6) Should the average RTC price be determined, pursuant to Rule 2015 (b)(1)(E), to have exceeded $15,000 per ton, within six months of the determination thereof, the Executive Officer shall submit to the Air Resources Board and the Environmental Protection Agency the results of an evaluation and review of the compliance and enforcement aspects of the RECLAIM program, including the deterrent effect of Rule 2004 paragraphs (d)(1) through (d)(4). This review shall be in addition to the audits to be performed pursuant to Rule 2015. The evaluation shall include, but not be limited to, an assessment of the rates of compliance with applicable emission caps, an assessment of the rate of compliance with monitoring, recordkeeping and reporting requirements, an

assessment of the ability of the South Coast Air Quality Management District to obtain appropriate penalties in cases of noncompliance, and an assessment of whether the program provides appropriate incentives to comply. The Executive Officer shall submit, with the results of the evaluation, either a recommendation that paragraphs (d)(1) through (d)(4) be continued without change, or amendments to the RECLAIM rules setting forth revisions to paragraphs (d)(1) through (d)(4) of Rule 2004, if the District's Governing Board determines that revisions are appropriate in light of the results of the evaluation.

(7) Power Producing Facilities shall rejoin the full RECLAIM program in the 2004 compliance year only if it is determined by the Governing Board in a public hearing prior to July 2003 that their reentry will not result in any negative impact on the remainder of the RECLAIM facilities or on California's energy security needs.

(c) AQMP Revisions

(1) In conjunction with the preparation of future AQMP revisions, the Executive Officer shall evaluate the relative potential emission reductions between RECLAIM and non-RECLAIM sources. Said evaluation shall include consideration of technology advancements and cost-effectiveness. The Executive Officer will propose to the Governing Board, AQMP revisions which ensure that any increases in Allocations which occur based on any adjustments made pursuant to Rule 2002 (c)(12), Rule 2015 (c)(2), and Rule 2015 (e) shall be offset in the AQMP.

(2) In conjunction with the preparation of future AQMP revisions, the Executive Officer will quantify additional energy demand and the potential need for increased Allocations resulting from implementation of the AQMP. In accordance with the results of the evaluation, the Executive Officer will propose amendments to Rule 2002, if appropriate, and if amendments are adopted, the Executive Officer will recalculate the Allocations for the year 2003 and subsequent years, and will issue these Allocations to affected electric generating and natural gas distribution facilities. The Executive Officer's evaluation will establish a need for any such increase in Allocations.

(3) Evaluation of Emission Factors

(A) In conjunction with the preparation of the 1994 AQMP revision, the Executive Officer will complete the evaluation of the ending emission factors found in Tables 1 and 2 of Rule 2002 for the source categories listed in subparagraph (c)(3)(B) of this rule. The Executive Officer shall take into account the environmental, energy, and economic impacts by each source category in evaluating the achievability of NO_X emission reduction technologies for each source category. In accordance with the results of the evaluation, the Executive Officer will propose amendments to Rule 2002, if appropriate, and if amendments are adopted, the Executive Officer will recalculate and reissue all affected Allocations for RECLAIM facilities in the source categories found in subparagraph (c)(3)(B). The Executive Officer will propose that any increases in Allocations which occur based on any adjustments made pursuant to this provision shall be offset in the AQMP.

(B) The Executive Officer will reevaluate the ending emission factors for the following source categories in accordance with subparagraph (c)(3)(A):

(i) glass melting furnaces;

(ii) gray cement kilns;

(iii) steel slab reheating, flat rolled product annealing and flat rolled product galvanizing furnaces;

(iv) metal melting furnaces;

(v) hot mix asphalt operations; and

(vi) petroleum coke calciners (NOx only).

(C) The Executive Officer will reevaluate the accuracy of emission factors for SO_3 emissions from petroleum refineries. In accordance with the results of the evaluation, the Executive Officer will propose amendments to Regulation XX, which may include, but are not limited to:

(i) enhanced monitoring requirements; and

(ii) revision of Allocations.

(D) For gray portland cement kilns, the operator may submit a plan no later than August 1, 1996 for the Executive Officer's approval which sets forth an alternative to the NOx emissions factor listed in Table 1 of Rule 2002. The plan shall include: (i) a demonstration of indirect firing with a low-NOx burner and mid kiln firing NOx reduction technologies; and (ii) emission testing pursuant to District approved methods of such demonstration that shall be completed and submitted to the AQMD by March 1, 1998. If the demonstration is completed in accordance with the requirements and timeline specified in this subparagraph and the demonstration of this emission factor shows a higher NOx emission factor than the emission factor listed in Table 1 of Rule 2002, the Executive Officer shall change the NOx ending emission factor and reissue all affected Allocations for RECLAIM facilities for gray cement kilns.

(d) Program-Specific Backstops

(1) Based on annual and three-year audits conducted pursuant to paragraphs (b)(1) and (b)(3), or upon discovery by the Executive Officer, the Executive Officer will propose that the Governing Board amend the program to address any specific program problems. In addition, upon discovery that actual emissions from RECLAIM sources exceeded Allocations for any annual period by five percent or greater, the Executive Officer will propose amendment to the RECLAIM program to the Governing Board. Recommendation may include, but are not limited to:

(A) restricting trading;

(B) requiring pre-approval of trades;

(C) enhanced monitoring;

(D) increasing rates of reduction;

(E) implementing technology-specific emission reductions; and

(F) increased penalties.

(2) If such program adjustments are determined to have failed to correct the specific program problems, the Executive Officer shall recommend that the Governing Board, after holding a Public Hearing, consider reinstating all or a portion of the source category-specific emission limits or control

measures contained in the then current AQMP in lieu of the RECLAIM program.

(3) Beginning with the Annual Audit for the 2004 compliance year, conducted pursuant to paragraph (b)(1), the Executive Officer will:

(A) annually compare the total quantity of NOx and SOx breakdown emissions that were not counted against RECLAIM facility annual Allocations, pursuant to Rule 2004(i)(3)(D), to the amount of unused RTCs for the entire RECLAIM program for the same compliance year covered in the Annual Audit, and

(B) subtract the full amount of unmitigated breakdown emissions from unused RTCs available, and if the unmitigated breakdown emissions exceed the unused RTCs for the same compliance year covered by the Annual Audit, any excess breakdown emissions remaining will either be offset:

(i) by adjusting all RTC holdings from the facilities that had unmitigated breakdown emissions from the compliance year following the completion of the Annual Audit based on a proportion of each facility's contribution to the total amount of unmitigated breakdown emissions, applied to the excess breakdown emissions remaining, and rounded to the nearest pound; and/or

(ii) with RTCs obtained by the Executive Officer from the compliance year following the completion of the Annual Audit in an amount sufficient to offset the unmitigated breakdown emissions.

(e) Severability, Effect of Judicial Order

In the event that any portion of this regulation is held by judicial order to be invalid or inapplicable with respect to any source or category of sources, such order shall not affect the validity or applicability of this regulation to any other sources. In such event, all emission limitation provisions listed in Rule 2001 Table 1 and Table 2, which in the absence of Rule 2001 would be applicable to such source or category of sources, shall become effective immediately; or if the emission limitation provisions require the installation of control equipment, one year after such order. In addition, the Executive Officer will, as expeditiously as possible, propose rules for adoption by the Governing Board which will require that each source or source category affected by the order comply with emission limitations representing Best Available Retrofit Control Technology, as defined in Health and Safety Code Section 40406.

(Adopted May 11, 2001)

RULE 2020. RECLAIM RESERVE

(a) Purpose

The purpose of this rule is to create a Reserve of NO_x emission reductions that can be used for the RECLAIM Air Quality Investment Program (RECLAIM AQIP), Mitigation Fee Program, or natural gas turbine power plant peaking sources.

(b) Applicability

(1) Use of emission reductions from the Reserve for the RECLAIM AQIP is limited to RECLAIM facilities that meet the criteria specified in Rule 2004 subdivision (p).

(2) Use of emission reductions from the Reserve for the mitigation fee program is limited to existing power producing facilities that meet the criteria specified in Rule 2004 paragraph (o)(1).

(3) Use of emission reductions from the State Emission Reduction Credit Bank is limited to natural gas turbine power plant peaking sources that meet the criteria of Executive Order D-24-01 dated February 8, 2001 and modified by Executive Order D-28-01 dated March 8, 2001, and Letter of Agreement executed on May 2, 2001.

(c) Definitions

(1) CONTROL STRATEGY PROPOSAL means a stationary, area or mobile source emission reduction control strategy proposal where NOx emission reductions would be generated pursuant to an emissions quantification protocol as defined under paragraph (c)(2).

(2) EMISSIONS QUANTIFICATION PROTOCOL OR PROTOCOL means an emissions quantification methodology contained in a District rule adopted after January 1, 2001 that authorizes the generation of emission reduction credits from specific activities within specific source categories for use in RECLAIM, such as paragraph (b)(1) of Rule 1612.1, Rule 1631, Rule 1632, Rule 1633, and Rule 2507. For the purpose of this rule, the term, "emission quantification protocol or protocol" shall include, as applicable, the following provisions of credit generation rules:

definitions, credit generation requirements, application, MSERC or ASC quantification, source category evaluation, credit issuance, monitoring, recordkeeping, and reporting, reconciliation and/or validation, credit use, loss or malfunction, and penalties.

(3) NEW FACILITY means a facility where all of the equipment has been either constructed or installed on or after January 1, 2001 and meets or is less than Best Available Control Technology (BACT) emissions level, pursuant to Rule 2005.

(4) PARTICIPATION FEE means the amount of money per pound of NO_x emission reductions that must be paid to the District to obtain NO_x emission reductions from the Reserve.

(5) PROVIDER means any person or interested party that submits a control strategy proposal that agrees to provide NO_x emission reductions for the Reserve for a specified amount of money per pound of NO_x emission reductions.

(6) RESERVE is a pool of emission reductions that has been generated, verified pursuant to an emissions quantification protocol and designated for use in the RECLAIM AQIP or Mitigation Fee Program and credits available from the State Emission Reduction Credit Bank.

(7) STATE EMISSION REDUCTION CREDIT BANK is a bank of emission reductions established pursuant to Executive Order D-24-01 dated February 8, 2001 and modified by Executive Order D-28-01 dated March 8, 2001, and Letter of Agreement between the District and ARB executed on May 2, 2001 for use by natural gas turbine power plant peaking sources. The bank is funded from emission reductions made pursuant to the Carl Moyer Memorial Air Standards Attainment Program, established pursuant to the California Health and Safety Code, Chapter 9, Sections 44275, 44280 – 44288, 44290, 44291, 44295 – 44297, 44299, and 44299.1. Reductions in the bank were generated pursuant to the applicable criteria specified in the Carl Moyer Guidelines, Part II, dated February 1, 1999, and as amended pursuant to Health and Safety Code Section 44287(b), dated November 16, 2000, as follows:

Chapter I:	Program Requirements;
Chapter II:	On-Road Heavy-Duty Vehicles;
Chapter III:	Off-Road Equipment;

Chapter IV:	Locomotives;
Chapter V:	Marine Vessels;
Chapter VI:	Stationary Agricultural Engines;
Chapter VII:	Additional Source Categories (February 1, 1999 only);
Chapter VII:	Forklifts (added November 16, 2000);
Chapter VIII:	Airport Ground Support Equipment (added November 16, 2000);
Chapter IX:	Particulate Matter Emission Reduction Requirements and Goal (added November 16, 2000); and
Chapter X:	Auxiliary Power Units for Reducing Idling Emissions from Heavy-Duty Vehicles (added November 16, 2000).

(d) The Reserve

(1) On and after May 11, 2001 the Executive Officer will create a Reserve of NO_x emission reductions that can be used for:

(A) the RECLAIM AQIP;

(B) the Mitigation Fee Program; or

(C) peaking units that are qualified to use reductions from the State Emission Reduction Credit Bank.

(2) Emission reductions in the Reserve, except for credits from the State Emission Reduction Credit Bank, shall be generated by an emission reduction provider that meets the requirements specified in subdivision (e). However, emission reductions obtained from the State Emission Reduction Credit Bank may be used in the Reserve so long as they are limited in their use pursuant to criteria set forth in Executive Order D-24-01 dated February 8, 2001 and modified by Executive Order D-28-01 dated March 8, 2001, and Letter of Agreement between the District and ARB executed on May 2, 2001.

(3) Although no additional control strategy proposals will be accepted by the Executive Officer on and after January 1, 2004, all emission reductions generated through implementation of the project will be designated to the Reserve for the entire implementation of the project.

(e) Provider Requirements for the AQIP and Mitigation Fee Program

(1) Any person that elects to generate NO_x emission reductions for the Reserve for the AQIP and Mitigation Fee Program shall:

(A) Prior to January 1, 2004, submit a control strategy proposal to generate NO_x emission reductions for use in the Reserve that meets the requirements specified in paragraph (e)(5);

(B) Receive written notification from the Executive Officer that the control strategy proposal was selected for implementation for a specified dollar amount per pound of NO_x emissions reduced; and

(C) Upon notification by the Executive Officer to implement a Proposal, the Provider shall, within the time period specified in the Control Strategy Proposal implement the Proposal and comply with requirements specified in the applicable emissions quantification protocol including definitions and requirements for, but not limited to, credit generation, credit quantification, monitoring, recordkeeping, and reporting (MRR) requirements, credit reconciliation and/or validation, evaluation year, and penalties.

(2) Upon implementation, the Executive Officer will verify the amount of NO_x emission reductions generated pursuant to the applicable emissions quantification protocol.

(3) In accordance with the credit issuance, credit reconciliation and/or validation provisions specified in the applicable emissions quantification protocol, the NO_x emission reductions shall be placed in the Reserve for use in the RECLAIM AQIP or Mitigation Fee Program and the Provider will receive payment for the implementation of the approved control strategy proposal.

(4) All emission reductions generated through implementation of the control strategy shall be designated to the Reserve for the entire implementation of the control strategy in accordance with the protocol.

(5) Control Strategy Proposal Requirements

Each control strategy proposal to generate NO_x emission reductions for the Reserve shall include the following information:

(A) A copy of the completed credit generation application required pursuant to the applicable emissions quantification protocol;

(B) The amount of NO_x emission reductions;

(C) Implementation cost of the control strategy proposal to achieve the stated NOx emission reductions calculated in dollars per pound of NO_x emission reductions; and

(D) Implementation schedule, timeframe for achieving emission reductions which should include the credit generation period and anticipated credit issuance pursuant to the emissions quantification protocol.

(6) Control strategy proposals will be prioritized by the Executive Officer for selection and implementation based on implementation cost and cost-effectiveness, amount of NO_x reduced, type of control strategy, location of control strategy, potential adverse environmental impacts; and implementation period of control strategy.

(f) RECLAIM AQIP, Mitigation Fee Program, or State Emission Reduction Credit Bank Requirements

(1) Effective on and after May 11, 2001, any facility that elects to obtain emission reductions from the Reserve for the RECLAIM AQIP, the Mitigation Fee Program, or State Emission Reduction Credit Bank shall:

(A) demonstrate that the facility is eligible to use these programs; and

(B) submit an AQIP or Mitigation Fee Registration to the Executive Officer pursuant to subdivision (g) for emission reductions requested through the 2004 compliance year; and

(C) pay a Participation Fee as specified in subdivision (h);

(2) Participation by facilities using NO_x emission reductions from the Reserve for the RECLAIM AQIP shall be temporarily halted if the emission reductions in the Reserve are less than the amount requested.

(3) Natural gas turbine power plant peaking sources that add new or expanded peaking capacity shall first access all available emission reductions via the State Emission Reduction Credit Bank pursuant to Executive Order D-24-01 dated February 8, 2001 and modified by Executive Order D-28-01, and Letter of Agreement executed on May 2, 2001. The sources shall meet the specified criteria of the Executive Orders and Letter of Agreement, including, but not limited to:

(A) the emission reduction credits will be leased, not to exceed 21 tons of NOx per year per peaking unit, for a period of no more than three years or no later than November 1, 2003, which ever is sooner, unless modified by agreement between the District and ARB and approved by EPA; and

(B) the facility pays the appropriate fees; and

(C) requests for reduction credits do not exceed the available credits in the State Emission Reduction Credit Bank.

(g) Registration

(1) Any person that elects to participate in the RECLAIM AQIP Program shall submit a completed Registration to the Executive Officer at least 60 days before the end of the quarter or compliance year in which emission reductions will be used. The Registration shall include the information as specified pursuant to paragraph (g)(4).

(2) Any person that elects to participate in the Mitigation Fee Program shall submit a completed Registration to the Executive Officer no later than when RTCs are needed to reconcile quarterly emissions, except for the first quarter of calendar year 2001, in which case Registrations to use the Mitigation Fee Program shall be submitted by June 11, 2001, and at least 60 days before the end of the compliance year that will have emissions greater than the facility's allocation. The Registration shall include information as specified pursuant to paragraph (g)(4).

(3) Any person that participates in the State Emission Reduction Credit Bank program shall submit a completed Registration to the Executive Officer.

(4) The Registration shall include, but is not limited to the following information:

(A) Facility name, Facility Identification Number, and location of the facility;

(B) Demonstration that the facility meets the applicability requirements;

(C) The amount of NO_x emission reductions requested; and

(D) The compliance year(s) in which the NO_x emission reductions will be used.

(5) The registration and participation fees are non-refundable upon acceptance of the submittal by the Executive Officer.

(6) Evaluation and Approval of the AQIP, Mitigation Fee Program, or State Emission Reduction Credit Bank Registration

The Executive Officer will approve or deny the AQIP, Mitigation Fee Program, or State Emission Reduction Credit Bank Registration within 30 days after a complete Registration is submitted to the Executive Officer. A Registration will be approved by the Executive Officer provided:

(A) the Executive Officer has received the Participation Fee pursuant to subdivision (h), as applicable;

(B) the Executive Officer has determined that the Registration is complete and demonstrates compliance with this rule; and

(C) for RECLAIM AQIP facilities, that the requirements specified in paragraph (f)(2) are met.

(h) Fees

(1) The Participation Fee for obtaining NO_x emission reductions from the Reserve for the Mitigation Fee Program and AQIP shall be set at $7.50 per pound of NO_x emission reductions unless, at a Governing Board meeting, the Governing Board approves a higher Participation Fee based on one or more of the following criteria.

(A) Control Strategy Projects cannot achieve a cost-effectiveness at or below $7.50 per pound of NO_x emission reductions; or

(B) Demand for AQIP emission reductions is increasing above the anticipated supply of reductions at $7.50 per pound of NO_x emission reductions.

(2) The participation fee for the State Emission Reduction Credit Bank shall be $6,000 per ton or $3,000 per ton for facilities that can demonstrate an agreement to sell their power under contract to the State Department of Water Resources.

(3) The Registration fee for submitting a request for either the AQIP or Mitigation Fee Program shall be assessed in accordance with Rule 306 – Plan Fees.

(i) Issuing Reductions from the Reserve

(1) NO_x emission reductions used for the RECLAIM AQIP, Mitigation Fee Program, or State Emission Reduction Credit Bank shall be converted

into RTCs and shall be designated as non-tradeable RTCs for the current compliance year. NOx emission reductions generated for AQIP and Mitigation Fee Program shall not be converted into RTCs until the emission quantification protocols used to generate the reductions have been approved into the State Implementation Plan.

(2) For AQIP participants, upon approval of a Registration, the Executive Officer will add RTCs pursuant to paragraph (i)(1) into the facility's allocation account specified in the approved Registration.

(3) For Mitigation Fee Program participants, upon verification of emission reductions that are placed in the Reserve pursuant to paragraph (e)(3), NO_x emission reductions used in the Mitigation Fee Program shall be designated for use in the compliance year(s) in which RTCs were deducted, pursuant to Rule 2010, replenishing the allocation account closest to the current compliance year first. The amount of emission reductions issued from the mitigation fee program shall be in accordance with Rule 2004, paragraph (o)(2).

(4) The amount of NO_x emission reductions available in the Reserve will be updated to reflect the amount of emission reductions:

(A) that are specified in approved Registrations; and

(B) that have been generated, verified, and issued pursuant to paragraph(e)(3).

(5) The amount of NO_x emission reductions placed in the Reserve shall represent the amount of emission reductions that are generated pursuant to the State Emission Reduction Credit Bank, or emissions quantification protocol (after application of any discounts) and credit issuance provisions pursuant to the protocol, as applicable. Emission reductions generated for the RECLAIM AQIP and Mitigation Fee Program shall not be used until the emission quantification protocols used to generate the reductions have been approved into the State Implementation Plan.

(6) Any additional NO_x emission reductions beyond those designated pursuant to Registrations generated through implementation of control strategy projects that are more cost-effective than the participation fee may be designated to the Reserve for use by the Executive Officer.

(7) The Executive Officer may combine funding from the RECLAIM AQIP and Mitigation Fee Program to fund control strategy proposals.

(8) NO_x emission reductions for each program and each control strategy proposal will be maintained separately.

(j) Penalties

Any Provider that fails to implement its approved control strategy proposal shall be subject to the applicable penalty provisions specified in the emissions quantification protocol.

(k) Program Review

The Executive Officer will submit a report to the Governing Board no later than April 1, 2002, and every 12 months thereafter until April 1, 2005. The report will include:

(1) The amount of emission reductions that have been generated over the past 12 months, that have been obtained, and that remain in the Reserve;

(2) Number and types of facilities, including location, that have participated in the RECLAIM AQIP and Mitigation Fee Program;

(3) Description of the types of emission reduction control strategy projects that have been or are being implemented;

(4) Location of the emission reduction control strategy projects;

(5) Evaluation of the participation fee; and

(6) Evaluation of the participation fee; and

(A) the amount of credits converted to RTCs;

(B) the amount of credits used at non-RECLAIM facilities; and

(C) the number of gas turbines, including location, capacity, date of operation, and projected and actual emissions, if available.

(Adopted May 7, 2021)

RULE 2305. WAREHOUSE INDIRECT SOURCE RULE – WAREHOUSE ACTIONS AND INVESTMENTS TO REDUCE EMISSIONS (WAIRE) PROGRAM

(a) Purpose

The purpose of this rule is to reduce local and regional emissions of nitrogen oxides and particulate matter, and to facilitate local and regional emission reductions associated with warehouses and the mobile sources attracted to warehouses in order to assist in meeting state and federal air quality standards for ozone and fine particulate matter.

(b) Applicability

This rule applies to owners and operators of warehouses located in the South Coast Air Quality Management District (South Coast AQMD) jurisdiction with greater than or equal to 100,000 square feet of indoor floor space in a single building.

(c) Definitions

For the purpose of this rule, the following definitions shall apply:

(1) ALTERNATIVE ENERGY GENERATION EQUIPMENT means systems at a warehouse facility capable of generating electricity without the use of diesel or gasoline.

(2) ALTERNATIVE-FUELED VEHICLE means a vehicle or engine which is not powered by gasoline or diesel fuel.

(3) ALTERNATIVE FUELING STATION means fuel dispensing equipment for alternative-fueled vehicles.

(4) CLASS 2B TRUCK means a truck with a Gross Vehicle Weight Rating (GVWR) of 8,501 to 10,000 pounds.

(5) CLASS 3 TRUCK means a truck with a GVWR of 10,001 to 14,000 pounds.

(6) CLASS 4 TRUCK means a truck with a GVWR of 14,001 to 16,000 pounds.

(7) CLASS 5 TRUCK means a truck with a GVWR of 16,001 to 19,500 pounds.

(8) CLASS 6 TRUCK means a truck with a GVWR of 19,501 to 26,000 pounds.

(9) CLASS 7 TRUCK means a truck with a GVWR of 26,001 to 33,000 pounds.

(10) CLASS 8 TRUCK means a truck with a GVWR of greater than 33,001 pounds.

(11) COLD STORAGE WAREHOUSE means a warehouse that temporarily stores perishable goods which are required to be either refrigerated or frozen.

(12) COMPLIANCE PERIOD means the 12-month period during which a warehouse facility or land owner, or operator is required to earn Points, as specified in paragraph (d)(1).

(13) DIESEL PARTICULATE MATTER (DPM) means the particles found in the exhaust of diesel fueled internal combustion engines. DPM is a component of fine particulate matter.

(14) DWELL TIME means the number of hours per day a truck or tractor is parked at a warehouse.

(15) ELECTRIC CHARGER means an electric charging station for vehicles that can operate at 208 Volts or greater. Each unique plug that can charge an individual vehicle at any time, regardless of whether other electric chargers/plugs are operating, counts as one electric charger. This equipment is also referred to as Electric Vehicle Supply Equipment (EVSE).

(16) FUEL TYPE means the fuel used to power a vehicle, such as electricity, hydrogen, natural gas, gasoline, or diesel fuel.

(17) MERV 16 means the minimum efficiency reporting value of filters used in heating, ventilation, and air conditioning units that remove at least 95% of particles 0.3 microns and larger as stated in the American Society of Heating, Refrigerating and Air-Conditioning Engineers Standard 52.2.

(18) NEAR-ZERO EMISSIONS (NZE) TRUCKS means trucks or tractors with engines meeting the California Air Resources Board's lowest non-zero optional NOx standard applicable at the time of manufacture as defined in the California Code of Regulations Title 13, section 1956.8.

(19) NITROGEN OXIDES (NOx) mean the sum of nitric oxides and nitrogen dioxides emitted, calculated as nitrogen dioxide.

(20) PARENT COMPANY means a company or other entity that owns a controlling interest in a company directly or through one or more subsidiaries.

(21) STRAIGHT TRUCK means a truck that carries cargo on the same chassis as the power unit and cab.

(22) TRACTOR means a heavy-duty Class 7 or 8 truck designed to pull a semi-trailer.

(23) TRANSPORT REFRIGERATION UNIT (TRU) means a refrigeration system designed to control the environment of temperature sensitive products transported in trucks or trailers.

(24) TRUCK CLASS means the size of a truck based on its GVWR.

(25) TRUCK TRIP means the one-way trip a truck or tractor makes to or from a site with at least one warehouse to deliver or pick up goods stored at that warehouse for later distribution to other locations. A truck or tractor entering a warehouse site and then leaving that site counts as two trips.

(26) VEHICLE MILES TRAVELED (VMT) means total annual miles of vehicle travel.

(27) WAREHOUSE means a building that stores cargo, goods, or products on a short- or long-term basis for later distribution to businesses and/or retail customers.

(28) WAREHOUSE FACILITY means a property that includes a warehouse as well as accessory uses such as parking areas and driving lanes for trucks, trailers, or passenger vehicles; entry and exit points for vehicles; accessory maintenance or security buildings; and fueling or charging infrastructure for vehicles.

(29) WAREHOUSE FACILITY OWNER means the legal, beneficial, and/or equitable owner or owners of a warehouse facility.

(30) WAREHOUSE LAND OWNER means the legal, beneficial, and/or equitable owner or owners of the land beneath a warehouse facility.

(31) WAREHOUSE OPERATOR means the entity who conducts day-to-day operations at a warehouse, either with its employees or through the contracting out of services for all or part of the warehouse operations. A warehouse operator can be, but is not necessarily the warehouse owner.

(32) WAREHOUSE SIZE means the indoor floor space, measured in square feet, of an individual warehouse building that may be used for warehousing activities.

(33) WAREHOUSING ACTIVITIES means operations at a warehouse related to the storage and distribution of goods, including but not limited to the storage, labelling, sorting, consolidation and deconsolidation of products into different size packages. Supporting office administration, maintenance, manufacturing areas, or retail sales areas open to the general public, within the same warehouse building, that are physically separate from the warehouse area, are not considered warehousing activities for the purpose of this rule.

(34) YARD TRUCK means a mobile utility vehicle, that operates as either an on- or off-road vehicle, used to carry cargo containers with or without a chassis; also commonly known as a terminal tractor, utility tractor rig, yard tractor, yard goat, or yard hostler.

(35) ZERO-EMISSION (ZE) TRUCK has the same meaning as "zero emission vehicle" defined in California Code of Regulations, Title 13, Section 1963.

(d) Requirements

(1) WAIRE Points Compliance Obligation

Beginning with the Initial Reporting Date in Table 1, a warehouse operator shall earn the applicable WAIRE Points, for the prior 12-month period from January 1 through December 31, in the amount specified in subparagraph (d)(1)(A). WAIRE Points shall only be earned for actions and investments completed during the compliance period while the warehouse operator used the warehouse, except as specified in paragraph (d)(6). Only warehouse operators in buildings with greater than or equal to 100,000 square feet of floor area that may be used for warehousing activities and who operate at least 50,000 square feet of the warehouse for warehousing activities are required to earn WAIRE Points.

(A) The number of WAIRE Points that a warehouse operator must earn in the applicable compliance period shall be calculated according to the following equation.

$$WPCO = WATTs \times Stringency \times \begin{pmatrix} Annual \\ Variable \end{pmatrix}$$

Where:

WPCO	= WAIRE Points Compliance Obligation, or the number of WAIRE Points that a warehouse operator must earn every year
WATTs	= Weighted Annual Truck Trips as calculated in subparagraph (d)(1)(B) or (d)(1)(C), as applicable
Stringency	= 0.0025 WAIRE Points per WATT
Annual Variable	= As specified in Table 2

(B) The Weighted Annual Truck Trips (WATTs) at a warehouse include all actual truck trips that occurred at a warehouse while the warehouse operator was responsible for warehousing activities during the compliance period. If a warehouse is used by more than one warehouse operator, the WATTs are calculated only for truck trips to or from that operator. As specified in the WAIRE Program Implementation Guidelines, actual truck trip data to a warehouse shall be collected by the warehouse operator using methods that provide a verifiable and representative record, and WATTs shall be calculated according to the following equation.

$$WATTs = [Class\ 2b\ to\ 7\ truck\ trips] + [2.5 \times Class\ 8\ truck\ trips]$$

Where:

Class 2b to 7 truck trips	= All trucks or tractors entering or exiting a warehouse truck gate(s) or driveway(s) that are truck Class 2b, 3, 4, 5, 6, or 7. If truck class information is not available, Class 2b to 7 trucks are all straight trucks that entered or exited a warehouse truck gate(s) or driveway(s).
Class 8 truck trips	= All Class 8 trucks or tractors entering or exiting a warehouse truck gate(s) or driveway(s). If truck class information is not available, Class 8 trucks are all tractors that entered or exited a warehouse truck gate(s) or driveway(s).

(C) If a warehouse operator does not have information about the number of truck trips at a warehouse due to a force majeure event such as a destruction of records from a fire, the WATTs shall be calculated according to the following equation.

$$WATTs = Days\ per\ Year \times Warehouse\ Size \times WTTR$$

Where:

Days per Year	=	The number of days that the warehouse operator has operational control of the warehouse during the compliance period
Warehouse Size	=	Warehouse size in thousand square feet (tsf), as defined in subdivision (c)
WTTR	=	Weighted Truck Trip Rate, where: Warehouses $\geq$200,000 = 0.95 trips/tsf/day Warehouses $\geq$100,000 = 0.67 trips/tsf/day Cold Storage Warehouses = 2.17 trips/tsf/day

(2) Earning WAIRE Points

WAIRE Points shall only be earned through completing actions in the WAIRE Menu in Table 3 and as described in (d)(3), or by completing actions in an approved Custom WAIRE Plan as described in (d)(4), or by choosing to pay a mitigation fee as described in (d)(5), or using any combination from (d)(3), (d)(4), or (d)(5).

(3) WAIRE Points Earned Using the WAIRE Menu

WAIRE Points may be earned for actions completed in the WAIRE Menu in Table 3 and based on the point values specified therein.

(A) WAIRE Points may not be earned from WAIRE Menu items in Table 3 if those same actions or investments are required by separate United States Environmental Protection Agency (U.S. EPA), California Air Resources Board (CARB), or South Coast AQMD rules and regulations during the compliance period in paragraph (d)(1). Actions or investments that go beyond U.S. EPA, CARB, or South Coast AQMD rules and regulations can earn WAIRE Points.

(4) WAIRE Points Earned Using a Custom WAIRE Plan

(A) Warehouse facility or land owners, or operators may apply to earn WAIRE Points through a customized plan for their facility. The Custom WAIRE Plan application shall follow the WAIRE Implementation Guidelines and the criteria below.

(i) Custom WAIRE Plan applications must demonstrate how the proposed action will earn WAIRE Points based on the incremental cost of the action, the NOx emission reductions from the action, and the DPM emission reductions from the action, relative to baseline conditions if the warehouse operator had not completed the action in that compliance period.

(ii) The methodology to determine the total WAIRE Points for an action in a Custom WAIRE Plan application shall be consistent with methods in the WAIRE Program Implementation Guidelines.

(iii) Any WAIRE Points earned from a Custom WAIRE Plan for emission reductions must be quantifiable, verifiable, and real as determined by the Executive Officer and consistent with the WAIRE Implementation Guidelines.

(iv) Custom WAIRE Plan applications must include the elements described below:

(I) A description of how the proposed actions will achieve quantifiable, verifiable, and real NOx and DPM emission reductions as quickly as feasible, but no later than three years after plan approval; and

(II) A quantification of expected NOx and/or DPM emission reductions from the proposed actions within the South Coast AQMD and within three miles of the warehouse; and

(III) A description of the method to be used to verify that the proposed actions will achieve NOx and/or DPM emission reductions; and

(IV) A schedule of key milestones showing the increments of progress to complete the proposed actions; and

(V) A description of the location and a map of where the proposed actions will occur; and

(VI) Any expected permits or approvals required by other private parties, or South Coast AQMD, or other federal, state, or local government agencies to implement the Custom WAIRE Plan.

(v) Any Custom WAIRE Plan that relies on VMT reduction must demonstrate that these reductions are surplus to what is included in the most recently approved Regional Transportation Plan (RTP) and Air Quality Management Plan (AQMP).

(B) Review of Custom WAIRE Plan Applications

(i) A Custom WAIRE Plan application must be submitted at least 270 days before an Annual WAIRE Report is due for the compliance period in which the Plan will earn Points.

(ii) Within 30 days of receipt of the Custom WAIRE Plan, the Executive Officer will conduct an initial review of the Custom WAIRE Plan and confirm receipt.

(iii) The Executive Officer shall approve or reject the Custom WAIRE Plan within 90 days of submittal. If no formal approval or rejection is received by the applicant, the application is presumed rejected unless otherwise provided for by the Executive Officer in writing. Approval or rejection will be based on whether:

(I) The Custom WAIRE Plan was prepared consistent with paragraph (d)(4)(A) and in accordance with the WAIRE Program Implementation Guidelines; and

(II) The information provided was complete and accurate.

(iv) Within 30 days of disapproval of a Custom WAIRE Plan application as specified in (d)(4)(B)(iii), a warehouse facility or land owner, or operator may revise and resubmit a Custom WAIRE Plan application that corrects all identified deficiencies. If the Executive Officer does not approve the subsequent revised plan within 45 days of resubmission, then no WAIRE Points may be earned from the Custom WAIRE Plan in the current compliance period.

(v) A Custom WAIRE Plan application shall be made available by the Executive Officer for public review no less than 30 days prior to approval.

(C) For any Custom WAIRE Plan that requires implementation beyond the subsequent Annual WAIRE Report, a progress report must be provided every 180 days after Custom WAIRE Plan approval. The progress report shall follow the WAIRE Program Implementation Guidelines and include at a minimum, all of the following:

(i) The key milestones from the approved Custom WAIRE Plan that were achieved and a schedule indicating dates for future increments of progress; and

(ii) Identification of any milestones that have been or will be achieved later than specified in the approved Custom Plan and the reason for achieving the milestones late. The progress report must describe how each late milestone will be achieved and when WAIRE Points are anticipated to be earned from that action.

(D) If the Executive Officer determines that a warehouse facility or land owner, or operator is not making adequate progress to complete an approved Custom WAIRE Plan, then the Executive Officer may rescind approval of the plan 30 days after notifying the plan applicant of the proposed rescission. The notice to the plan applicant shall contain a description of the identified deficiencies in the Custom WAIRE Plan implementation.

(i) If the warehouse facility or land owner, or operator does not subsequently demonstrate to the Executive Officer's satisfaction that the deficiencies in implementing the plan have been corrected, then the Executive Officer will rescind approval of the Custom WAIRE Plan and notify the owners or operators of the rescission.

(E) If the expected WAIRE Points from an approved Custom WAIRE Plan are not earned during the applicable compliance period, the warehouse facility or land owner, or operator whose Custom WAIRE Plan was approved shall be in violation of this rule unless the owner or operator demonstrates that they have met their Warehouse Points Compliance Obligation by the date that they submit their Annual WAIRE Report using WAIRE Points earned through requirements in paragraphs (d)(3) or (d)(5).

(5) Mitigation Fee

In lieu of earning the required number of WAIRE Points in paragraph (d)(3) or (d)(4) a warehouse facility or land owner, or operator may choose to satisfy all or any remaining part of their WAIRE Points Compliance Obligation through payment of a mitigation fee in the amount of $1,000 for each WAIRE Point. The mitigation fee shall be paid no later than when the applicable Annual WAIRE Report for that compliance period is due.

(6) Transferring WAIRE Points

WAIRE Points are not transferable, except as specified below.

(A) Transferring WAIRE Points to a Different Warehouse

If a warehouse operator conducts warehousing activities at more than one warehouse during any single compliance period, then WAIRE Points earned for one warehouse may be used at the other warehouse(s) under the operational control of that same warehouse operator. Only those points earned in excess of a warehouse operator's WAIRE Points Compliance Obligation at that site may be transferred, and only for the current compliance period. Any WAIRE Points transferred to a different warehouse shall be discounted as specified in the WAIRE Menu in Table 3.

(B) Transferring WAIRE Points to a Different Compliance Period

If a warehouse operator earns more WAIRE Points than is required for its annual WAIRE Points Compliance Obligation, then it may use those remaining WAIRE Points at the same warehouse to satisfy its WAIRE Points Compliance Obligation in any of the following three years.

(i) WAIRE Points may not be transferred to a subsequent compliance period if the WAIRE Menu items used to earn WAIRE Points are required by U.S. EPA, CARB, or South Coast AQMD rules and regulations in that subsequent year.

(ii) Warehouse facility or land owners, or operators transferring WAIRE Points to a different compliance period shall demonstrate that any onsite improvements or equipment installations that were used to earn the WAIRE Points being transferred are still operational at that warehouse facility in the year that WAIRE Points are used.

(iii) WAIRE Points earned prior to a warehouse operator's first compliance period pursuant to paragraph (d)(1) may be banked and transferred up to three years after the warehouse operator's first compliance period. This early compliance must be documented in an Annual WAIRE Report immediately following the year in which the action or investment was completed.

(C) Transferring WAIRE Points Between a Warehouse Facility or Land Owner and a Warehouse Operator

A warehouse facility or land owner may earn WAIRE Points during a compliance period using the methods specified in paragraphs (d)(3), (d)(4), or (d)(5) or may have WAIRE Points transferred to them from the warehouse operator at that site. The warehouse facility or land owner may transfer these WAIRE Points to any warehouse operator at the site where the WAIRE Points were earned within a three-year period after the points were earned. Points used in this three-year period are subject to clause (d)(6)(B)(ii).

(7) Reporting

(A) Warehouse Operations Notification

Warehouse facility owners shall notify the South Coast AQMD in the manner specified in paragraph (e)(1) on September 1, 2021 and subsequently thereafter when any of the following conditions occur:

(i) Within 14 calendar days after a new warehouse operator has the ability to use at least 50,000 square feet of a warehouse that has greater than or equal to 100,000 square feet used for warehousing activities;

(ii) Within 30 calendar days after a renovated warehouse has received a certificate of occupancy from the local land use agency such that the total warehouse space that may be used for warehousing activities has increased or decreased; or

(iii) Within three calendar days of a request from the Executive Officer.

(B) Initial Site Information Report

Warehouse operators shall submit an Initial Site Information Report in the manner specified in paragraph (e)(2) no later than July 1 of the year that they must submit their first annual WAIRE Report for their operations at that warehouse facility, or within 30 calendar days of a written request by the Executive Officer.

(C) Annual WAIRE Report

Warehouse operators who are required to earn WAIRE Points, or warehouse facility or land owners who earn WAIRE Points as applicable, shall submit an Annual WAIRE Report in the manner specified in paragraph (e)(3) no more than 30 calendar days after January 1, beginning with the Initial Reporting Date in Table 1. The Annual WAIRE Report, in accordance with the WAIRE Program Implementation Guidelines, shall include the information described in paragraph (e)(3) to demonstrate how the warehouse operator satisfied the requirement of paragraph (d)(1) in the preceding compliance period.

(D) If a warehouse operator vacates a warehouse prior to the Annual WAIRE Report submission date in subparagraph (d)(7)(c) in any year that they must satisfy an annual WAIRE Points Compliance Obligation, then the Annual WAIRE Report shall be submitted to South Coast AQMD no later than the date that they vacate the warehouse.

(e) Reporting, Notification, and Recordkeeping Requirements

(1) Warehouse Operations Notification

The notification required pursuant to subparagraph (d)(7)(A) shall be made in the manner specified by the Executive Officer and the WAIRE Program Implementation Guidelines. The notification shall include:

(A) The legal name and contact information of any entity leasing at least 50,000 square feet of space at that warehouse and of the warehouse facility owner and land owner, or an affirmation if no entities lease at least 50,000 square feet of space at that warehouse;

(B) The duration of the current lease term, if applicable;

(C) The warehouse size(s) and the square footage that may be used for warehousing activities by each entity leasing at least 50,000 square feet of space at a warehouse; and

(D) The last known legal name and contact information of the previous entity or entities leasing at least 50,000 square feet of space at that warehouse and the end date of the previous entity's lease, if applicable; and

(E) How many square feet of the warehouse is used by the warehouse facility owner for warehousing activities.

(2) Initial Site Information Report

The Initial Site Information Report required in subparagraph (d)(7)(B) shall be made in the manner specified by the Executive Officer and the WAIRE Implementation Guidelines, and shall include the following information:

(A) Warehouse size, and the square footage that may be used for warehousing activities within their operational control.

(i) If the warehouse building has less than 100,000 square feet that may be used for warehousing activities, then no additional information pursuant to subparagraphs (e)(2)(B) through (e)(2)(G) is required.

(ii) Any operator leasing less than 50,000 square feet of warehouse space that may be used for warehousing activities is not required to report additional information pursuant to subparagraphs (e)(2)(B) through (e)(2)(G), unless the same parent company owns or controls multiple operators in the same building who collectively use greater than or equal to 50,000 square feet of warehousing space for warehousing activity.

(B) Actual truck trip data, including:

(i) Number of truck trips in the previous 12-month period for the warehouse operator at that warehouse;

(ii) Number of truck trips anticipated for the next applicable 12-month compliance period in subdivision (d); and

(iii) For the purposes of this subparagraph, truck trips shall be reported in two categories. The first category shall include all trucks or tractors using a facility's truck gate or driveway that are truck Class 2b through truck Class 7, or straight trucks if truck class information is not available. The second category shall include all trucks and tractors that are truck Class 8, or all tractors if truck class information is not available.

(C) If the warehouse operator owns or leases on-road trucks or tractors that serve that warehouse, the Initial Site Information Report shall include fleet data, for the previous 12-month period including:

(i) Number of trucks and tractors in the fleet serving that warehouse, by truck class, and fuel type;

(ii) Total VMT by truck class and fuel type; and

(iii) Typical dwell time at the facility by truck class; and

(iv) Information about which trucks or tractors are owned or leased.

(D) If the warehouse has an alternative fueling station(s) or electric charging station(s) located onsite, the Initial Site Information Report shall include:

(i) Number of electric chargers/alternative fueling stations installed and the date of installation. The report must include the level for each electric charging station. For alternative-fueling stations, the report must include the fuel type, maximum fuel dispensing rate, the maximum amount of fuel that can be dispensed daily, and the pressure of the fueling system, if applicable;

(ii) Types of vehicles served;

(iii) Total fuel dispensed and/or charging provided in the previous 12-month period.

(E) If the warehouse operator has yard trucks that are used at that warehouse facility, the Initial Site Information Report shall include:

(i) Number of yard trucks used in the previous 12-month period, and indicate which of these are registered as motor vehicles under Vehicle Code section 4000, et seq.;

(ii) Fuel type and engine size; and

(iii) Total annual hours of operation of all yard trucks for the previous 12-month period.

(F) If the warehouse has onsite alternative energy generation equipment and/or onsite energy storage equipment, the Initial Site Information Report shall include:

(i) The type and rated capacity of the alternative energy generation system in kilowatts and kilowatt-hours per year, and/or rated capacity of the energy storage system in kilowatt-hours, as applicable.

(ii) The total energy generation and/or usage of the energy storage system in kilowatt hours expected during the next applicable compliance period in subdivision (d).

(G) The Initial Site Information Report shall include whether the warehouse operator anticipates earning WAIRE Points from the WAIRE Menu, from a Custom WAIRE Plan, or by choosing to pay a mitigation fee, or the combination thereof, for the next applicable compliance period in subdivision (d). If the warehouse operator anticipates using the WAIRE Menu, the anticipated actions in the WAIRE Menu shall be reported. The actual WAIRE Menu items used for compliance can be from the methods reported in the Initial Site Information Report, or from any other category in the WAIRE Menu, or any other method to earn WAIRE Points in paragraph (d)(2).

(3) Annual WAIRE Report

Annual WAIRE Reports required pursuant to subparagraph (d)(7)(C) or (D) shall be made in the manner specified by the Executive Officer and as specified in the WAIRE Implementation Guidelines, and shall include the following information:

(A) The Annual WAIRE Report shall include truck trip data, including:

(i) Number of actual truck trips during the compliance period described in paragraph (d)(1); and

(ii) Truck trips shall be reported in the same manner as described in subparagraph (e)(2)(B)(iii)

(B) The Annual WAIRE Report shall include how many WAIRE Points were earned from the WAIRE Menu specified in paragraph (d)(3), an approved Custom WAIRE Plan specified in paragraph (d)(4), from mitigation fees specified in paragraph (d)(5), or from transferred WAIRE Points specified in paragraph (d)(6).

(C) For every WAIRE Menu item used to earn WAIRE Points, the WAIRE Annual Report shall contain information about the Reporting Metric specified in Table 3.

(D) Every Annual WAIRE Report shall include current contact information for the warehouse operator.

(4) Recordkeeping

Records which document the accuracy and validity of all information submitted to the South Coast AQMD as required by this rule shall be kept by the warehouse facility or land owner, or operator as applicable, for a minimum of seven years from the reporting deadline, and made available upon request during normal business hours.

(A) A warehouse operator relying on WAIRE Points transferred from a warehouse facility or land owner pursuant to subparagraph (d)(6)(C) must possess records for how the WAIRE Points were earned if they are used to satisfy a WPCO.

(B) Records documenting how WAIRE Points were earned must have been collected contemporaneously with the action itself.

(5) All reports in this rule shall be certified by an authorized official. For purposes of reporting, an authorized official is defined as an individual who has knowledge and responsibility for actions required by this rule, and who has been authorized by an officer of the warehouse facility or land owner, or operator, as applicable, to submit and certify the accuracy of the data presented in these reports on behalf of the owner or operator, based on best available knowledge.

(f) WAIRE Implementation Guidelines

The Executive Officer shall periodically publish guidelines for implementing the WAIRE Program.

(g) Exemptions

(1) Operators In Warehouses That Have Less Than 50,000 Square Feet That They May Use For Warehousing Activities

Warehouse operators who can only use less than 50,000 square feet of a warehouse that is greater than or equal to 100,000 square feet, for warehousing activities due to terms of their lease, are not subject to the requirements in subdivision (d)(1) unless the same parent company owns or controls multiple operators in the same building who collectively use more than 50,000 square feet of space for warehousing activity.

(2) Warehouse Operators With a WPCO Less Than 10

A warehouse operator with a WPCO that is less than 10 in any compliance period is exempt from the requirement to earn WAIRE Points in paragraph (d)(1) for that compliance period. The WPCO shall be calculated using methods in paragraph (d)(1). The warehouse operator shall document their WPCO and exemption in an Annual WAIRE Report.

(3) Unforeseen Circumstances

In instances where investments or actions completed by an owner or operator perform at a level significantly lower than anticipated due to unforeseen circumstances beyond the control of the warehouse facility or land owner, or operator and such that the anticipated WAIRE Points for that action cannot be fully earned, the owner or operator may apply for a partial or complete exemption to the Executive Officer following procedures in the WAIRE Program Implementation Guidelines. The application must specify what portion of the WPCO determined by subparagraph (d)(1) that the malfunctioning equipment would have satisfied, and relevant details about why the anticipated action was unable to earn the expected WAIRE Points.

(A) The Executive Officer shall grant an exemption from the applicable WAIRE Points requirement only if the following criteria are met:

(i) The vehicle or equipment does not perform at the level specified by the manufacturer due to a manufacturing defect or a defect in the installation of equipment using manufacturer-approved methods, and

(ii) The warehouse operator demonstrates that despite their good faith effort to have the vehicle or equipment repaired, either via warranty or through other manufacturer and/or installer-approved methods, that the repair was not completed in a timely manner.

(h) Sunset Date for Rule

The WPCO requirements in (d)(1) shall expire 45 days after the end of the compliance period during which the latter of (h)(1) and (h)(2) has been met.

(1) A final action becomes effective from the U.S. EPA that finds that all air basins within the South Coast AQMD have attained the 2015 National Ambient Air Quality Standards (NAAQS) for ozone of 70 parts per billion.

(2) Pursuant to Health and Safety Code 39608, CARB has identified that all air basins in the South Coast AQMD have attained the state ozone standard of 70 parts per billion.

(3) All reporting requirements for warehouse facility and land owners and operators shall remain in effect for the final compliance period specified in (h), but no reporting shall be required for future compliance periods.

(4) At least one year prior to the anticipated rule expiration in (h), the Executive Officer shall report to the South Coast AQMD Governing Board on the efficacy of Rule 2305 and recommend which portions of the rule should be retained or amended, if any. This report shall evaluate the potential need for the rule with respect to any applicable Clean Air Act requirements such as anti-backsliding and maintenance plans, other regulations from U.S. EPA and CARB, the state of the market of zero emission and near zero emission technologies serving warehouses, and the existing and anticipated emissions associated with warehouses covered by the rule.

(i) Severability

If any provision of this rule is held by judicial order to be unlawful or otherwise invalid, such order shall not affect the operation or implementation of the remainder of this rule. If any provision of this rule is held by judicial order to be inapplicable to any person or circumstance, such order shall not affect the application of such provision to other persons or circumstances. The severability provided for in this subsection shall include, but is not limited to, invalidation of any exemption in subsection (g) or any of the compliance options in subsections (d)(3), (d)(4), or (d)(5) or the actions in Table 3.

Table 1 – Initial Requirement Date

Phase	Warehouse Size (square feet)	Initial Reporting Date (Annual WAIRE Report)	Initial Compliance Period
1	≥ 250,000	January 31, 2023	January 1, 2022 to December 31, 2022
2	≥ 150,000-<250,000	January 31, 2024	January 1, 2023 to December 31, 2023
3	≥ 100,000-<150,000	January 31, 2025	January 1, 2024 to December 31, 2024

Table 2 – Annual Variable

Annual WAIRE Report Year*	Annual Variable		
	Phase 1	Phase 2	Phase 3
2022	0.33	0	0
2023	0.67	0.33	0
2024	1.0	0.67	0.33
2025	1.0	1.0	0.67
2026 and beyond	1.0	1.0	1.0

* This is the compliance period for which a warehouse operator is first required to submit its Annual WAIRE Report.

Table 3 WAIRE Menu

Action/Investment	Action/Investment Details	Reporting Metric	Annualized Metric	WAIRE Points per Annualized Metric	Discounted WAIRE Points Subparagraph (d)(6)(A)
Acquire ZE/NZE Trucks in Warehouse Operator Fleet	ZE Class 8	Number of trucks	One truck acquired	126	126
	ZE Class 4-7			68	68
	ZE Class 2b-3			14	14
	NZE Class 8			55	55
	NZE Class 4-7			26	26
ZE/NZE Truck Visits	ZE Class 8	Number of visits	365 truck visits	51	33
	ZE Class 4-7			12	9
	ZE Class 2b-3			9	6
	NZE Class 8			42	24
	NZE Class 4-7			12	9
Acquire ZE Yard Truck		Number of yard trucks	One yard truck acquired	177	177
Use ZE Yard Truck		Hours of use	1,000 hours	291	51
Install Onsite ZE Charging or Fueling Infrastructure	150-350 kW EVSE Acquisition	Number of EVSE purchased	One EVSE purchased	118	118
	51-149 kW EVSE Acquisition			51	51
	19.2-50 kW EVSE Acquisition			26	26
	Up to 19.2 kW EVSE Acquisition			5	5
	TRU Plug EVSE Acquisition			3	3
	Begin construction on 19.2-350 kW charger project	First day of construction	One construction project	9	9
	Begin construction on up to 19.2 kW charger project			5	5
	Begin construction on TRU Plug project			5	5
	Finalize 19.2-350 kW Level charger project	The latter of final permit sign off or charger energization	One construction project	59	59
	Finalize up to 19.2 kW charger project			5	5
	Finalize TRU Plug project			7	7
	Hydrogen (H_2) Station	Daily capacity of station in kilograms (kg)	One 700 kg/day station construction project	1,680	1,680
Use Onsite ZE Charging or Fueling Infrastructure	Vehicle Charging	Kilowatt-hours (kWh) of dispensed electricity	165,000 kWh	42	24
	TRU Charging		10,658 kWh	10	3
	H_2 Station Usage	Kg of dispensed H_2	6,152 kg	43	25
Install and Energize Onsite Solar Panels	Rooftop	Size of system in kW	100 kW system	15	15
	Carport			19	19
Use Onsite Solar Panels		Energy production in kWh	165,000 kWh	1	1
Install MERV 16 or greater Filters or Filter Systems in Residences, Schools, Daycares, Hospitals, or Community Centers	Install Stand-Alone System	Number of systems installed	25 systems	55	55
	Replace Filters	Number of filters replaced	200 filters	51	51

9/5/14

(Adopted May 2, 2008)(Amended July 11, 2014)

RULE 2449. CONTROL OF OXIDES OF NITROGEN EMISSIONS FROM OFF-ROAD DIESEL VEHICLES

The provisions of Article 4.8, Chapter 9, Title 13 of the California Code of Regulations (CCR), Section 2449.3, in effect June 15, 2008, were adopted in full by the South Coast Air Quality Management District on May 2, 2008 through the "opt-in" provision provided in the regulation and were made part of the Rules and Regulations of the South Coast Air Quality Management District.

Article 4.8, Chapter 9, Title 13 of the CCR, Section 2449.3 was amended in December 14, 2011 by the California Air Resources Board and renumbered to section 2449.2. Effective December 14, 2011 Section 2449.2 shall apply to the owner of any off-road diesel vehicle as described.

The provisions of this Regulation apply to the owner of any off-road diesel vehicle as described in Section 2449.2(b) operating in the South Coast Air Quality Management District. Upon the District's issuance of a solicitation for applications for funding, fleet owners subject to Section 2449.2 shall submit applications for funding, in accordance with the Rule 2449 Administrative Guidelines developed to implement Section 2449.2.

Title 13, Chapter 9	**Motor Vehicles – Off-Road Vehicles and Engines Pollution Control Devices**
Section 2449.3	**Surplus Off-Road Opt-In for NOx (SOON) Program**
	(13 CCR 2449.3, June 15, 2008) (SCAQMD Adopted May 2, 2008)
Section 2449.2	**Surplus Off-Road Opt-In for NOx (SOON) Program**
	(13 CCR 2449.2, December 14, 2011) (SCAQMD Amended July, 11, 2014)

5/31/01

(Adopted May 11, 2001)

RULE 2507. PILOT CREDIT GENERATION PROGRAM FOR AGRICULTURAL PUMPS

(a) Purpose

The purpose of this rule is to provide opportunities to generate NO_x area source credits (ASCs) for use in RECLAIM through the voluntary electrification of agricultural pumps.

(b) Applicability

(1) This rule applies to persons who voluntarily elect to generate NO_x ASCs, which may be used in RECLAIM through the replacement of an existing diesel-fueled engine used to power an agricultural pump with an electric motor.

(2) This rule does not apply to any:

(A) emission reductions produced by monies from any public air quality related funding program including but not limited to Rule 2202, the Carl Moyer Memorial Air Quality Standards Attainment Program, or AB2766 funding except funds exclusively collected for and designated by the Executive Officer for credit generation projects; or

(B) emission reductions required pursuant to any law, rule, or regulation, or legal instrument such as a legal settlement or consent decree.

(c) Definitions

(1) ACTIVITY LEVEL (AL) means for the purpose of this rule, the amount of kilowatt-hours (kW-hr) of energy or diesel fuel consumed per year for each electric motor or engine used within the District.

(2) AGRICULTURAL PUMP means for the purpose of this rule, a stationary pump less than 600 horsepower used to move water for irrigation purposes.

(3) APPLICATION means for the purpose of this rule, the Rule 2507 ASC Application as specified in subdivision (e).

(4) AREA SOURCE CREDIT (ASC) means for the purpose of this rule, emission reduction credits that meet the requirements of this rule and are issued as specified in subdivision (h).

(5) BASELINE EMISSION FACTOR (EF_{base}) means for the purpose of this rule, the emission factor used to quantify annual emissions from a new diesel-fueled engine used to supply power to an agricultural pump that would have been purchased in lieu of an electric motor.

(6) CREDIT GENERATION PERIOD means the timeframe that ASCs are being generated and begins on the date that the requirements of subdivision (d) are met and can extend no longer than the lifetime of the original diesel-fueled engine, except as provided in subdivision (i). The first segment of the credit generation period, which may be 12 months or less, is referred to as the "initial credit generation period" and each 12 month segment of the credit generation period thereafter, is referred to as the "annual credit generation period."

(7) CREDIT ISSUANCE PERIOD means the timeframe that ASCs are issued and begins on the date that the requirements of subdivision (h) are met.

(8) DIESEL FUEL means any fuel that is commonly known as diesel fuel No. 1-D or 2-D, or meets the specifications in ASTM D 975, Standard Specifications for Diesel Fuel Oils.

(9) DISTRICT means the geographical area defined by Rule 103 – Definition of Geographical Area.

(10) EVALUATION YEAR means for the purpose of this rule, 2006 which represents the initial evaluation year and subsequent years thereafter as determined pursuant to paragraph (g)(3) during which the District, CARB, and EPA will assess whether ASCs may continue to be generated or if a portion or all future ASCs need to be discontinued or discounted to ensure credits remain surplus.

(11) RECLAIM FACILITY means any stationary source subject to Regulation XX, pursuant to Rule 2001 - Applicability.

(12) RETIRE OR RETIRED means that the credit, regardless of the expiration date of the credit, can no longer be transferred or used.

(13) SURPLUS means that emission reductions achieved throughout the duration of the emission reduction activity that are not required or relied upon by any local, state, or federal rule, or regulation, and the federal

Clean Air Act; and are not required or relied upon in an attainment demonstration, reasonable further progress demonstration, or emissions inventory thereby ensuring that there is no double counting of emission reductions.

(d) Credit Generator Requirements

Any person that elects to generate ASCs under this rule shall meet all of the following requirements:

(1) Replace a diesel-fueled engine with an electric motor that is used to power an agricultural pump;

(2) Demonstrate that the purchase contract for acquisition of the new replacement electric motor was signed no earlier than March 1, 2001 and that installation of the electric motor did not occur prior to May 11, 2001;

(3) Demonstrate that each agricultural pump is located in the district;

(4) Demonstrate that all agricultural pumps, are equipped with a non-resettable meter capable of measuring the kilowatt-hours consumed;

(5) Submit an Application as specified in subdivision (e); and

(6) Demonstrate compliance with the monitoring, recordkeeping, and reporting requirements specified in subdivision (j).

(e) Application

(1) Any person that elects to generate ASCs under this rule shall submit an Application to the District no later than 30 days after the initial electric motor replacement and before January 1, 2004. The Application shall include the following:

(A) A description of the project, including, at a minimum, the location of the field or agricultural area where the agricultural pumps are installed, plot plan identifying specific location of the pumps in the field and the location of the meter required pursuant to paragraph (d)(5), number of agricultural pumps, and pump identification;

(B) Identification of the existing diesel-fueled engines powering the pumps and new electric motors including each engine and motor manufacturer, model, model year, and horsepower;

(C) The projected installation date of each new electric motor that would represent the beginning of the credit generation period;

(D) Identification of the intended user(s) of the ASCs, if available.

(E) The historical annual average activity level for each existing diesel-fueled engine in the previous calendar two-year period; and

(F) Designation of the RECLAIM Compliance Cycle for each agricultural pump for the initial and each annual credit generation period for the entire credit generation period.

(G) The projected activity level for the initial credit generation period and the projected annual activity level after the initial credit generation period which coincides with either RECLAIM Compliance Cycle 1 or 2, up to the evaluation year, not to exceed a five-year credit generation period. The projected activity level for any single new replacement electric motor should not exceed 120% of the most recent two-year historical annual average activity level specified in subparagraph (e)(1)(E).

(2) If the installation date, as specified in subparagraph (e)(1)(C) of the electrified agricultural pump is before the Application is approved, the Application shall include the following additional information:

(A) Proof of installation of the new replacement electric motor;

(B) Proof that the original diesel-fueled engine is destroyed, sold, or otherwise transferred or relocated to a new owner who operates the engine outside of the district with the location and identity of the new owner, if applicable, along with a copy of a written notification informing the new owner that the original engine must not be operated, sold, or otherwise transferred or delivered in the district or in Ventura or Santa Barbara Counties; and

(C) Written certification or signed declaration from the credit generator that any original diesel-fueled engine that is not sold, scrapped, or otherwise transferred to a new owner or location outside the district has not been, and will not be operated within the district or in Ventura or Santa Barbara Counties during the credit generation period.

(3) If the installation date, as specified in subparagraph (e)(1)(C) is after the Application is approved, the credit generator shall provide information specified under paragraph (e)(2) prior to credit issuance pursuant to paragraph (h)(1).

(4) The Application shall be deemed a plan, and plan fees shall be assessed in accordance with Rule 306– Plan Fees.

(5) The Executive Officer shall approve or disapprove the Application and any subsequent revisions submitted pursuant to paragraph (e)(6), in writing within 90 days of submittal of a complete Application or Application revision.

(6) Any person that submits an Application may amend the Application to revise:

(A) information provided under subparagraphs (e)(1)(A) through (e)(1)(E) at any time; or

(B) the original projected activity levels specified in subparagraph (e)(1)(G) no later then 180 days after the beginning eligibility credit issuance date pursuant to subparagraph (h)(2)(B).

(C) remove an agricultural pump from the Application, provided the credit generator retires ASCs or ASCs converted into RTCs to cover reductions projected for that agricultural pump for the entire current and subsequent credit generation periods in which the use of the pump would have generated credits.

(7) An Application shall not be amended to add an agricultural pump that is removed from the Application pursuant to subparagraph (e)(6)(C) until the following annual credit generation period.

(8) The credit generation period shall begin no earlier then the date the Application is received by the district.

(f) ASC Quantification

(1) ASCs for agricultural pumps shall be quantified using the following equation:

$$ASC = \frac{(EF_{base} - EF_{opt}) \times AL}{454}$$

Where

ASC	=	Area Source Credit (pounds)
EF_{base}	=	The Baseline emission factor (g/kW-hr)
EF_{opt}	=	Optional emission factor (g/kW-hr)
AL	=	Activity level (kW-hr)
454	=	Conversion factor from grams to pounds

(2) The projected and actual activity level used to quantify the ASCs shall be determined from the information submitted pursuant to subdivisions (e) and (j), respectively.

(3) To quantify ASCs for engines that are replaced with an electric motor on or after January 1, 2001, the credit generator shall use the values of baseline and optional emission factors in Table 1 – NO_x Baseline and Optional Emission Factors based on the horsepower of the replaced engine and the year the existing diesel-fueled engine is replaced.

(4) For purposes of quantifying the historical annual average activity level for each existing diesel-fueled engine in the previous calendar two-year period, a conversion factor of 14.9 kW-hr/gallon (20 bhp-hr/gallon) shall be used to convert the gallons of fuel used per year to kilowatt-hours consumed per year.

(g) Source Category Evaluation

(1) On or before July 1, 2006, the Executive Officer with CARB and EPA shall complete an evaluation on Agricultural pumps and agree whether future ASCs need to be either discontinued or discounted to ensure credits remain surplus.

(2) The evaluation shall include, but is not limited to, an assessment of current and future local, state, and federal rules and regulations affecting each source category.

(3) After the initial evaluation year, the evaluation performed in paragraph (g)(1) shall be completed on a timeframe as agreed to by the District, CARB, and EPA, but not more than once per year.

(4) Subsequent evaluations performed pursuant to paragraph (g)(3) shall be completed at least six months prior to end of each evaluation period specified in paragraph (g)(3), for the remainder of the pilot program.

(5) No future ASCs shall be issued if the evaluation is not completed or the District, CARB and EPA do not agree on whether future ASCs need to be discontinued or the amount that the ASCs need to be discounted.

(h) Credit Issuance

(1) The Executive Officer shall issue ASCs provided the credit generator has written approval of the Application and has provided the information specified in paragraph (e)(2).

(2) The Executive Officer shall issue ASCs:

(A) in pounds of NO_x for the amount indicated in the approved Application in one-year increments:

(B) designated with a beginning and ending date based on the date of credit issuance;

(C) for the number of annual credit issuance periods up to December 31 of the evaluation year and shall be based on the annual projected activity level specified in subparagraph (e)(1)(G); and

(D) discounted upon issuance by:

(i) nine percent which will be retired for the benefit of the environment; and

(ii) one percent which will either fund the Rule 518.2 – Federal Alternative Operating Conditions offset program, or if Rule 518.2 funding is not needed, be retired for the benefit of the environment.

(3) Any reductions other than NO_x that result from implementation of projects subject to this rule shall be retired for the benefit of the environment and ineligible for transfer or use.

(4) The actual amount of ASCs issued shall be based on the approved Application, or any subsequent verification by the Executive Officer.

(5) ASCs converted to RTCs shall be issued for either RECLAIM Compliance Cycle 1 or 2 provided that each annual credit generation period coincides with the entire cycle selected. If the initial credit generation period begins prior to the start of a complete RECLAIM Compliance Cycle, that portion of ASCs converted to RTCs shall be

issued for the current or previous cycle provided that this initial credit generation period completely coincides with the cycle selected.

(6) Any ASCs not used by the specified expiration date shall be retired to benefit the environment and be ineligible for transfer or use.

(i) Loss or Malfunction

(1) If any agricultural pump identified in the approved Application is replaced due to loss or a malfunction that is not the result of normal use during the current credit generation period, the credit generator shall replace the agricultural pump with a pump powered by an electric motor.

(2) The credit generator shall be responsible for obtaining credits and surrendering them to the Executive Officer to make up any potential shortfall in credits according to the reconciliation procedures of subdivision (k) as a result of the following:

(A) any agricultural pump destroyed or malfunctions after 10 years from the initial credit issuance date;

(B) any agricultural pump that is not replaced pursuant to paragraph (i)(1); and/or

(C) any reduction in activity level during the replacement of the malfunctioning agricultural pump.

(3) Notwithstanding the requirements of paragraph (i)(2), no additional ASCs shall be issued:

(A) due to the agricultural pump having a higher baseline emission factor than that used for the original agricultural pump; or

(B) for use of the replacement agricultural pump beyond the current credit generation period.

(j) Monitoring, Recordkeeping, and Reporting

(1) For all agricultural pumps identified in the approved Application, credit generators shall monitor and maintain quarterly records of the number of kilowatt-hours of energy that is supplied to the agricultural pump based on a kilowatt-hour meter at the beginning and end of each quarter.

(2) For each agricultural pump, credit generators shall maintain quarterly records of:

(A) the location of the agricultural pump;

(B) agricultural pump identification, electric motor make, model, model year, and serial number;

(C) agricultural pump loss, or sale; and

(D) when an agricultural pump is replaced due to loss or malfunction, identification of each replaced and replacement agricultural pump including make, model, model year, and serial number;

(3) Within 30 days after the end of each twelve-month credit generation period, the credit generator shall submit:

(A) the activity level specified in paragraph (j)(1) for the previous twelve-month credit generation period; and

(B) the information specified in subparagraphs (j)(2)(A) through (j)(2)(D) if any agricultural pump identified in the Application is replaced, lost, or sold.

(4) Notwithstanding paragraph (j)(3), if the initial credit generation period begins prior to the start of a complete RECLAIM Compliance Cycle and is three months or less, the credit generator shall submit the information specified in paragraph (j)(3) within 30 days after the end of the annual credit generation period following the initial credit generation period. For an initial credit generation period that is greater than three months, the credit generator shall submit the information specified in paragraph (j)(3) within 30 days after the end of the initial credit generation period.

(5) If the evaluation performed under subdivision (g) indicates that a portion or all future ASCs are surplus, and if the credit generator elects to continue generating ASCs, at least 60 days before the end of the evaluation year, the credit generator shall submit the projected annual activity level for the following credit generation period, not to exceed five years.

(k) Annual Reconciliation

(1) The actual activity level submitted pursuant to paragraphs (j)(3) and (j)(4) shall be reviewed by the Executive Officer upon submittal to evaluate if any shortfall exists between the actual activity level and the projected activity level.

(2) If a shortfall exists between the actual and projected activity levels, the credit generator and user are subject to the penalty provisions specified under subdivision (m).

(3) If the actual activity level exceeded the projected activity level, then the Executive Officer shall, after performing the evaluation required by paragraph (k)(1), issue additional ASCs equal to the amount of the increase and pursuant to subdivision (h) for use in the RECLAIM Compliance Cycle that ends no later than six months from the last day of the credit generation period of which the increase in activity level occurred.

(l) Credit Use

ASCs generated under this rule may be used as RTCs in the RECLAIM program.

(m) Penalties

(1) If a shortfall exists pursuant to paragraph (k)(1), credits equal to 110 percent of the shortfall shall be obtained and surrendered to the Executive Officer such that the applicant shall retire NO_x ASCs generated under the same or different Application or RTCs that are approved and designated for use within the same RECLAIM cycle or if not available, from the next RECLAIM cycle.

(2) Any person submitting an Application who falsifies information in the Application or fails to implement any provision of the Application, shall be subject to the penalties specified in the Health and Safety Code for violation of District rules and shall be grounds for the Executive Officer to take one or more of the following actions:

(A) disapprove the Application and void all previously issued ASCs, and those already converted to RTCs, that have not yet expired;

(B) designate the applicant to be ineligible to generate ASCs; or

(C) assess the penalty specified in paragraph (m)(1).

(3) If the shortfall cannot be reconciled through paragraph (m)(1), any person who uses ASCs converted into RTCs generated under this rule at a RECLAIM facility where there is a shortfall in emission reductions or where previously issued ASCs, and those already converted to RTCs, that have not yet expired are voided, shall be subject to the provisions specified in Rule 2010 – Administrative Remedies and Sanctions for RECLAIM rule violations. If there are multiple credit holders or users of credits generated under the same Application, each holder or user shall

retire ASCs or RTCs according to their prorated share of credits purchased.

(n) Program Review

(1) On or before March 2003 and biannually thereafter, up until credits are discontinued according to the source category evaluation performed pursuant to subdivision (g), the Executive Officer shall complete a review and present a report to the Governing Board that includes but not be limited to the following information:

(A) General description of projects participating in the pilot program and the amount of NO_x ASCs, including the amount converted to RTCs, generated under the pilot program;

(B) The location of the credit generation projects and facilities using RTCs under this pilot program;

(C) The amount of NO_x ASCs retired to benefit the environment; and

(D) The amount of concurrent non-NO_x emission reductions such as PM and toxic air contaminants, generated under the pilot program that have been retired to benefit the environment.

(2) The Governing Board may suspend approval of pending Applications and receipt of additional Applications through a noticed public hearing.

Table 1

NO_x Baseline and Optional Emission Factors

Size (hp)	Replacement Year	NO_x[1] Baseline Emission Factor (g/kW-hr)	NO_x[1] Baseline Emission Factor (g/bhp-hr)	NO_x[2] Optional Emission Factor (g/kW-hr)
50≤ hp <100	2001 - 2003	9.2	6.9	0.1
50≤ hp <100	2004	7.0	5.2	0.1
100≤ hp <175	2001 - 2002	9.2	6.9	0.1
100≤ hp <175	2003 - 2004	6.2	4.6	0.1
175≤ hp <300	2001 - 2002	9.2	6.9	0.1
175≤ hp <300	2003 - 2004	6.2	4.6	0.1
300≤ hp <–600	2001 - 2004	6.0	4.5	0.1

1. Baseline emission factors represent NO_x portion only of a combined NO_x + THC standard based on 40CFR Part 89.112 – Control of Emissions of Air Pollution from Nonroad Diesel Engines and Title 13 California Code of Regulations Section 2423.
2. Optional emission factor based on in-Basin electric power production NO_x emission factor of 0.232 pounds per megawatt-hour.