Control Strategy Tool (CoST)
Cost Equations Documentation

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1 Introduction

EPA's Control Strategy Tool (CoST) estimates emissions reductions and costs associated with control measures applied to sources of air pollution. CoST merges the Control Measures Database (CMDB) with EPA emissions inventories to compute source- and pollutant-specific emissions reductions and associated costs at various geographic levels (national, regional, and/or local). The CMDB comprises control measure and cost information for reducing the emissions of criteria pollutants (e.g., NO_x, SO_2, VOC, PM_{10}, $PM_{2.5}$, and NH_3) from point and nonpoint sources.[1] Controls are matched to sources by the Source Classification Code (SCC) of the emissions inventory record.[2]

Cost equations are used to estimate costs of control measures for some point sources but are not used to estimate the costs for nonpoint sources. In general, CoST estimates the costs of emissions control technologies in one of two ways:

- Cost equations are used to determine engineering costs using relevant data for the source when data is available for those variables (currently 87, or 33%, of the control measures in the CMDB can use an equation if the necessary inventory variables are available for use)[3], or
- A simple cost factor in terms of dollars per ton of pollutant reduced is used to calculate the annual cost of the control measure.

CoST is a client-server system and is part of EPA's Emissions Modeling Framework (EMF). In the CoST client-server system, client software connects to a server running the CoST algorithms and database and performs the calculations. The cost equations used by CoST are stored in the EMF database, and the source code for these equations is available in the EPA GitHub repository at https://github.com/USEPA/emf/blob/master/EMF/deploy/db/cost/functions/cost_equations_v2.sql. This code includes the algorithms for several equation types that are no longer used by control measures in the current CMDB. These algorithms have been retained to enable compatibility with previous versions of the CMDB.

The remainder of this section provides background information on calculations to estimate capital recovery factors and to convert emissions inventory parameters for use in the cost equations. In Section 2, for each equation type currently used, the types of controls for which it is used is discussed along with the functional form of the equations and descriptions of the variables needed to estimate the equations. This information is summarized in a table in Section 3.

1 For more information about the types of point and nonpoint sources included in emissions inventories, see https://www.epa.gov/air-emissions-inventories/national-emissions-inventory-nei.

2 For more about Source Classification Codes, see https://sor-scc-api.epa.gov/sccwebservices/sccsearch/.

3 This count and associated percentage are based on the 4/28/2023 version of the CMDB. Some control measure abbreviations (e.g., NSCR_UBCT1, NSCR_UBCT2, NSCR_UBCT3, NSCR_UBCT4, and NSCR_UBCT5) are the same control technology applied to the same types of sources but reflecting a capacity constraint. Likewise, other control abbreviations (e.g., PESPIPSIZE1, PESPIPSIZE5, and PESPIPSIZE10) are the same control technology but applied to different SCCs based on the SCCs' average particle sizes. For the purpose of this count and percentage, these groups of control measure abbreviations are each considered a single control measure.

1.1 Capital Recovery Factor Equation

Throughout the document we provide equations to estimate annualized capital costs using a capital recovery factor (CRF). The following equation is used to estimate the CRF for the case of discrete interest compounding (i.e., not continuous compounding):

$$CRF = \frac{i \cdot (1+i)^n}{(1+i)^n - 1} \quad (1)$$

where
- i = annual interest rate
- n = expected economic life of the control equipment.

The CRF is calculated in CoST using the equipment life specified for each control measure in the CMDB and the interest rate specified when setting up a CoST run.

1.2 Emissions Inventory Unit Conversions

The cost equations in this document can use various parameters from the emissions inventory to determine the size of the emissions unit, which in turn may be used to calculate the capital and other costs of operation. Each equation requires specific units for the emissions inventory parameter used in the equation. Units for the emissions inventory parameters used in the equations are prescribed in the format of the inventory (see the SMOKE User's Manual for the required units).[4] For example, the exhaust gas flow rate must be reported as cubic feet per second. However, SMOKE provides flexibility for reporting the design capacity units. This requires a conversion of the units used in the emissions inventory to the units required for each cost equation.

1.2.1 Design Capacity Unit Conversions

The unit conversions for design capacity are relatively straightforward, as shown in the following equation:

$$DC_{eq} = c \cdot \delta \cdot DC_{inv} \quad (2)$$

where
- DC_{eq} = capacity of the emission process in units required by the CoST equation
- c = standard factor used to convert from emission inventory units to cost equation units
- δ = the ratio of the useful energy output by the system to the energy input to the system
- DC_{inv} = capacity of the emission process in units reported in the emissions inventory.

The following standard conversion factors are used in the CoST unit conversion algorithm, which first converts inventory units to a common unit (Megawatts Thermal [MWt]) and then converts

[4] The current SMOKE User's Manual is available at: https://www.cmascenter.org/smoke/documentation/4.9/html/. The format of inventory files is discussed in Section 6.2 at https://www.cmascenter.org/smoke/documentation/4.9/html/ch06s02.html.

MWt to the units required for each individual CoST equation. The factors used to convert between inventory units and MWt are as follows:

1 MWt = 3.412 million British Thermal Units per hour (MMBtu/hr or E6BTU/HR)
1 MWt = 1000 Kilowatt Thermal (KWt)
1 MWt = 1341.022 Horsepower (hp)
1 MWt = 101.93 Boiler Horsepower (BHP)

The combustion efficiency is based on the SCC and is retrieved from the CMDB SCC table. The combustion efficiency is the ratio of the useful *energy output* by the system to the *energy input* to the system. Most of the CoST equations are based on the size of the unit in terms of the *energy input* to the system. In that case, the combustion efficiency is not needed and effectively treated as 100% in the CoST unit conversion algorithm. However, for electric generating units (EGUs), the CoST equations are based on the size of the unit in terms of useful *energy output* from the system. In the electric power industry, there are two values assigned to a unit's design capacity: megawatts electric (MWe) and megawatts thermal (MWt). The former refers to the electricity output capability of the plant, and the latter refers to the input energy required. The efficiency of an EGU is equal to the ratio of the electric output of the plant to the overall thermal power needed to generate the electricity. For example, a coal-fired power plant rated at 1000 MWe will require supply of 3000 MWt of heat (e.g., approximately 10,236 MMBtu/HR) from burning coal for every 1000 MW of electricity it produces. The efficiency is specified for each SCC in the SCC table of the CMDB. Typical values are 33 to 35% for coal-fired plants.

1.2.2 Exhaust Gas Flowrate Unit Conversions

If reported, the exhaust gas flowrate in the emissions inventory must be reported as cubic feet per second, and it is assumed that the flowrate reported in the emissions inventory is at actual stack conditions. The exhaust gas flowrate is an optional variable, but the stack diameter and stack gas exit velocity variables are required. In cases where the flowrate is not provided, CoST will calculate the flowrate using the stack diameter and exit velocity.[5] Some of the cost equations in this document were developed using the actual flow rate, but others use the flow rate corrected to standardized properties of temperature and moisture content.[6] The following conversions are used when considering flowrate:

$$F_a = F_0 \cdot 60 \tag{3}$$

$$F_s = (F_a)\left(\frac{520}{460 + T}\right) \tag{4}$$

[5] The formula for calculating the flowrate is $VFR = SEV \cdot ((\pi \cdot D^2)/4)$, where VFR is volumetric flowrate (ft^3/min), SEV is stack exit velocity (ft/min), and D is stack diameter (ft).

[6] Standard cubic feet per minute is the volumetric flow rate of a gas stream at a standardized temperature and pressure. The standard condition for pressure is typically defined as 101,325 pascals, 14.696 psia, or 760 mm Hg, which is the mean sea-level atmospheric pressure. Standard temperature is variously defined as 70 °F, 68 °F, 60 °F, 0 °C, 15 °C, 20 °C, or 25 °C, depending on the establishing entity. The relative humidity is also included in some definitions of standard conditions.

$$F_d = (F_a)\left(\frac{460+68}{460+T}\right)\left(1-\frac{M}{100}\right) \quad (5)$$

where

F_0 = Stack gas flowrate (ft^3/s) from the emissions inventory
F_a = Actual exhaust flowrate (acfm)
F_s = Exhaust flowrate at standard temperature (scfm)
F_d = Exhaust flowrate at standard temperature on a dry basis (dscfm)
60 = Seconds to minutes conversion factor
T = Stack gas temperature (˚F) from the emissions inventory
M = Stack gas moisture content (%) from the CMDB equations table.

1.3 Terminology and Notation Conventions

In the equations that follow, the following conventions are adopted. Equation coefficients, constants, and exponents are referred to as parameters, and are denoted as p_1 – p_{12}. The subscript corresponds to that parameter's location in the CMDB equations file, where the values are labeled as *var1-var12*, to make it easier for the reader to cross-reference the parameters in the CMDB with the equations in this document.

2 Equations

The types of sources and control technologies that currently use each equation type in CoST are summarized below in Table 1. This is a general list, and some specific controls using an equation type may apply to only certain portions of the broader emissions source group. For example, a control may only apply to Industrial, Commercial, and Institutional (ICI) Boilers with a specific fuel type. More information about the specific types of sources to which a particular control measure applies, as well as descriptions of the control technologies, can be found in the references for each equation type listed in Table 2 and in the CMDB.

In the discussion that follows, some equation types vary depending on if the emissions source already has a relevant emissions control. This determination is made using the information in the *ann_pct_red* (annual percent reduction) column in the emissions inventory. If this column does not contain a value, the emissions source will be assumed to be uncontrolled.

Table 1. Types of Emissions Sources and Control Technologies Using Each Equation Type.

Equation Type	Pollutant	Emissions Source Group	Control Technology
Type 1	NO_x	• EGU Boilers	• Low NO_x Burner • Low NO_x Burner and Overfire Air • Low NO_x Coal-and-Air Nozzles with Close-Coupled Overfire Air • Low NO_x Coal-and-Air Nozzles with Close-Coupled and Separated Overfire Air • Low NO_x Coal-and-Air Nozzles with Separated Overfire Air • Selective Catalytic Reduction • Selective Non-Catalytic Reduction
	$PM_{2.5}$	• EGU Boilers	• Fabric Filter (Pulse Jet Type)
	SO_2	• EGU Boilers	• Lime Spray Dryer • Limestone Forced Oxidation
Type 2	NO_x	• Turbines	• Catalytic Combustion • Dry Low NO_x Combustion • EMx • EMx and Dry Low NO_x Combustion • EMx and Water Injection • Low NO_x Burner • Selective Catalytic Reduction and Dry Low NO_x Combustion • Selective Catalytic Reduction and Steam Injection • Selective Catalytic Reduction and Water Injection • Steam Injection • Water Injection
Type 2a	NO_x	• Glass Melting Furnaces	• Low NO_x Burner • Selective Catalytic Reduction
Type 2b	NO_x	• Internal Combustion Engines	• Low Emission Combustion
Type 2c	NO_x	• Internal Combustion Engines	• Air to Fuel Ratio Controller • Selective Catalytic Reduction
Type 8	$PM_{2.5}$	• Chemical Evaporation from Industrial Processes • Glass Melting Furnaces • ICI Boilers • Incinerators • Industrial Processes • Catalytic Cracking Units • Process Heaters • Space Heaters • Waste Disposal	• Electrostatic Precipitator (All Types) • Fabric Filter (All Types) • Venturi Scrubber

Equation Type	Pollutant	Emissions Source Group	Control Technology
	SO_2	• Chemical Evaporation from Industrial Processes • Glass Melting Furnaces • ICI Boilers • Incinerators • Industrial Processes • Internal Combustion Engines • Catalytic Cracking Units • Process Heaters • Space Heaters • Turbines • Waste Disposal	• Packed Bed Scrubber
	VOC	• Chemical Evaporation from Industrial Processes • Glass Melting Furnaces • Incinerators • Industrial Processes • Catalytic Cracking Units • Process Heaters	• Carbon Adsorber • Catalytic Oxidizer • Regenerative Thermal Oxidizer • Vapor Recovery Unit
Type 12	NO_x	• Process Heaters	• Excess O_2 Control • Selective Catalytic Reduction • Ultra-Low NO_x Burner
Type 13	NO_x	• ICI Boilers • Catalytic Cracking Units	• Flue Gas Recirculation • Low NO_x Burner • Low NO_x Burner and Flue Gas Recirculation • Low NO_x Burner and Selective Non-Catalytic Reduction • Ultra-Low NO_x Burner • Ultra-Low NO_x Burner and Selective Catalytic Reduction • Ultra-Low NO_x Burner and Selective Non-Catalytic Reduction
Type 18	SO_2	• EGU Boilers • ICI Boilers • Industrial Processes • Catalytic Cracking Units • Process Heaters • Space Heaters	• Increased Caustic Injection Rate for Existing Dry Injection Control
Type 20	NO_x	• ICI Boilers • Catalytic Cracking Units • Process Heaters • Space Heaters	• Selective Catalytic Reduction • Selective Non-Catalytic Reduction
	SO_2	• ICI Boilers • Catalytic Cracking Units • Process Heaters • Space Heaters	• Dry Scrubber • Wet Scrubber
Type 21	SO_2	• ICI Boilers	• Dry Scrubber • Wet Scrubber

2.1 Equation Type 1

Equation Type 1 is the only cost equation applicable to electric generating unit (EGU) point sources. The cost data in the CMDB for these sources was originally from the Integrated Planning Model (IPM) v3.0 (U.S. EPA, 2006) but has been updated periodically as IPM is updated.[7] The parameters currently used in the CMDB equations are from IPM v5.13 (U.S. EPA, 2013). While cost equations for EGUs are included in the CMDB for use with CoST, in regulatory applications these controls are traditionally not applied. Instead, we generally rely on output from IPM for analyses of costs for EGU sources and controls.

The data for this equation type was developed based on a series of model plants. The capacities of these model plants are used along with scaling factors and the emissions inventory's unit-specific boiler characteristics (e.g., boiler capacity, stack parameters) to generate a control cost for an applied technology. The scaling factor is used to adjust the capital and fixed operation and maintenance (O&M) costs associated with a control measure to the boiler size (MW) based on the original control technology's documentation. While the general form of this equation type allows for the use of a scaling factor, not all control measures that use this equation type make use of this capability. In these cases, the scaling factor reduces to 1.

NO_x control technologies using Equation Type 1 are:

- Low NO_x Burner
- Low NO_x Burner and Over Fire Air
- Low NO_x Coal-and-Air Nozzles with Close-Coupled Overfire Air
- Low NO_x Coal-and-Air Nozzles with Separated Overfire Air
- Low NO_x Coal-and-Air Nozzles with Close-Coupled and Separated Overfire Air
- Selective Catalytic Reduction
- Selective Non-Catalytic Reduction

The $PM_{2.5}$ control technology using Equation Type 1 is:

- Pulse Jet Type Fabric Filter

SO_2 control technologies using Equation Type 1 are:

- Lime Spray Dryer
- Limestone Forced Oxidation

2.1.1 Capital Cost Equation

For control measures using Equation Type 1, CoST calculates the capital cost associated with a control measure by applying a scaling factor to the calculations for an appropriate model plant; the

[7] IPM is a model used by EPA's Clean Air Markets Division to estimate the costs of control strategies applied to electric utilities. The current version is v6, but the parameters for combustion controls for NO_x are based on v5.13 because these controls have been removed from v6. More about the Integrated Planning Model can be found at https://www.epa.gov/power-sector-modeling,

scaling factor S is calculated based on the ratio of the model plant's capacity to the capacity of a boiler measured in megawatts (MW).

$$S = \left(\frac{p_4}{DC_{MW}}\right)^{p_5} \quad (6)$$

where

p_4 = scaling factor model size, the boiler capacity of the model plant (MW)
p_5 = scaling factor exponent, an empirical value based on the specific control measure
DC_{MW} = design capacity of the boiler (MW) (from the units used in the emissions inventory converted to MW, see Section 1.2 for a discussion of unit conversions)

The capital cost is a straightforward multiplication of the capital cost multiplier, the unit's boiler capacity (MW) from the emissions inventory, and the scaling factor that was calculated above.

$$Capital\ Cost = p_1 \cdot DC_{MW} \cdot S \cdot 1{,}000 \quad (7)$$

where

p_1 = capital cost multiplier, an empirical value based on the specific control measure ($/kW)
DC_{MW} = design capacity of the boiler (MW)
S = scaling factor
1,000 = unit conversion factor (converting $/kW to $/MW)

The following equation calculates the annualized capital cost. This is the annual cost of capital only; it does not include costs due to operation and maintenance.

$$Annualized\ Capital\ Cost = Capital\ Cost \cdot CRF \quad (8)$$

The *Capital Cost* is calculated as above and the Capital Recovery Factor *CRF* calculated as in Section 1.1.

2.1.2 Operation and Maintenance Cost Equations

Operation and maintenance (O&M) costs, which are also calculated on an annual basis, are in addition to the capital cost of equipment. These O&M costs are divided into fixed costs and variable costs. Fixed costs are incurred because the equipment exists whether or not it is in operation. Examples of fixed costs are property taxes, insurance, and administrative charges. The fixed O&M cost component is also based on the unit's capacity.

$$Fixed\ O\&M = p_2 \cdot DC_{MW} \cdot S \cdot 1{,}000 \quad (9)$$

where

p_2 = fixed O&M cost multiplier, an empirical value based on the control measure ($/kW)
DC_{MW} = design capacity of the boiler (MW)
S = scaling factor
1,000 = unit conversion factor (converting $/kW to $/MW)

The variable portion of the O&M costs includes an additional estimate for the unit's capacity factor, which is a factor reflecting the unit's utilization.

$$Variable\ O\&M = p_3 \cdot DC_{MW} \cdot p_6 \cdot 8{,}760 \tag{10}$$

where

- p_3 = variable O&M cost multiplier, an empirical value based on the specific control measure ($/MWh)
- DC_{MW} = design capacity (in megawatts)
- p_6 = capacity factor, which converts the design capacity or rated output of a power plant into the amount of actual power generated[8]
- 8,760 = assumed number of hours of operation per year

The O&M cost is then the sum of the annual fixed and variable O&M costs.

$$O\&M\ Cost = Fixed\ O\&M + Variable\ O\&M \tag{11}$$

2.1.3 Total Annual Cost Equation

The total annual cost is then calculated as the sum of the unit's annualized capital cost and the O&M costs.

$$Total\ Annual\ Cost = Annualized\ Capital\ Cost + O\&M\ Cost \tag{12}$$

2.2 Equation Type 2

Equation Type 2 estimates the cost of NO_x controls for gas-fired turbines. This equation type uses the design capacity from the input emissions inventory, converted from emissions inventory units to the unit (MMBtu/hour) required by the cost equations (see Section 1.2 for a discussion of this conversion). The control technologies are:

- Catalytic Combustion
- Dry Low NO_x Combustion
- EMx
- EMx and Dry Low NO_x Combustion
- EMx and Water Injection
- Low NO_x Burner
- Selective Catalytic Reduction and Dry Low NO_x Combustion
- Selective Catalytic Reduction and Steam Injection
- Selective Catalytic Reduction and Water Injection
- Steam Injection
- Water Injection

Equation Type 2 was derived based on a review of turbine control cost calculations and outputs from previous studies, which are discussed in RTI (2014). Costs based on this equation type are

8 If a power plant's design capacity is 500 MW, but the plant runs at 400 MW, its capacity factor is 80 percent.

estimated for units that have a design capacity not exceeding 2,000 million Btu per hour (MMBtu/hour). For those sources above the capacity threshold, a default cost per ton value is used along with the annual emissions reduction achieved by the applied control measure to calculate the total annual cost of the control measure (see Section 2.12).

2.2.1 Capital and Total Annual Cost Equations

The capital and total annual costs are estimated using one of the sets of equations below. If the emissions source does not already have a control listed in the inventory the equations for a new control are used, while if a control is already installed on a source, the equations for an add-on control are used.

New control:

$$Capital\ Cost = p_1 \cdot DC_{MMBtu/hr}^{p_2} + p_9 \tag{13}$$

$$Total\ Annual\ Cost = p_3 \cdot DC_{MMBtu/hr}^{p_4} + p_{10} \tag{14}$$

Add-on control:

$$Capital\ Cost = p_5 \cdot DC_{MMBtu/hr}^{p_6} + p_{11} \tag{15}$$

$$Total\ Annual\ Cost = p_7 \cdot DC_{MMBtu/hr}^{p_8} + p_{12} \tag{16}$$

where

$DC_{MMBtu/hr}$ = design capacity (in MMBtu/hr)
p_1 = capital cost multiplier for new control
p_2 = capital cost exponent for new control
p_3 = annual cost multiplier for new control
p_4 = annual cost exponent for new control
p_5 = capital cost multiplier for add-on control
p_6 = capital cost exponent for add-on control
p_7 = annual cost multiplier for add-on control
p_8 = annual cost exponent for add-on control
p_9 = capital cost constant for new control
p_{10} = annual cost constant for new control
p_{11} = capital cost constant for add-on control
p_{12} = annual cost constant for add-on control

The capital and annual cost multipliers, exponents, and constants are empirical values specific to control measures. Some measures may not have capital or annual cost constants, and the functional form can be made linear by setting the exponents equal to 1, which is the case with some of the CMDB measures currently using this equation type.

The annualized capital cost is then calculated as

$$Annualized\ Capital\ Cost = Capital\ Cost \cdot CRF \tag{17}$$

where *Capital Cost* is calculated using an equation above and the Capital Recovery Factor *CRF* is calculated as in Section 1.1.

2.2.2 Operation and Maintenance Cost Equation

The O&M cost is calculated by subtracting the annualized capital cost from the total annual cost.

$$O\&M\ Cost = Total\ Annual\ Cost\ -\ Annualized\ Capital\ Cost \tag{18}$$

where the *Total Annual Cost* and the *Annualized Capital Cost* were calculated previously.

2.3 Equation Type 2a

Equation Type 2a is used to calculate the cost of NO_x controls on glass manufacturing melting furnaces. This equation type uses the estimated daily emissions reduction from the application of the control measure, which is estimated using the reported emissions from the input emissions inventory and the control efficiency associated with the control in the CMDB. The control technologies are:

- Low NO_x Burner
- Selective Catalytic Reduction

The development of the controls using Equation Type 2a is discussed in RTI (2014). These controls were derived from previous studies combined with vendor quotes. Costs based on this equation type are estimated for units that have a design capacity not exceeding 2,000 million Btu per hour (MMBtu/hour). For those sources above the capacity threshold, a default cost per ton value is used along with the annual emissions reduction achieved by the applied control measure to calculate the total annual cost of the control measure (see Section 2.12).

2.3.1 Capital and Total Annual Cost Equations

The capital and total annual costs are estimated using one of the sets of equations below. If the emissions source does not already have a control listed in the inventory the equations for a new control are used, while if a control is already installed on a source, the equations for an add-on control are used.

New control:

$$Capital\ Cost = p_1 \cdot \left(\frac{ER}{365}\right)^{p_2} + p_9 \tag{19}$$

$$Total\ Annual\ Cost = p_3 \cdot \left(\frac{ER}{365}\right)^{p_4} + p_{10} \tag{20}$$

Add-on control:

$$Capital\ Cost = p_5 \cdot \left(\frac{ER}{365}\right)^{p_6} + p_{11} \tag{21}$$

$$Total\ Annual\ Cost = p_7 \cdot \left(\frac{ER}{365}\right)^{p_8} + p_{12} \tag{22}$$

where

ER = emissions reduction from application of the control technology (tons/day)
p_1 = capital cost multiplier for new control
p_2 = capital cost exponent for new control
p_3 = annual cost multiplier for new control
p_4 = annual cost exponent for new control
p_5 = capital cost multiplier for add-on control
p_6 = capital cost exponent for add-on control
p_7 = annual cost multiplier for add-on control
p_8 = annual cost exponent for add-on control
p_9 = capital cost constant for new control
p_{10} = annual cost constant for new control
p_{11} = capital cost constant for add-on control
p_{12} = annual cost constant for add-on control

The capital and annual cost multipliers, exponents, and constants are empirical values specific to control measures. Some measures may not have capital or annual cost constants, and the functional form can be made linear by setting the exponents equal to 1, which is the case with the CMDB measures currently using this equation type.

The annualized capital cost is then calculated as

$$Annualized\ Capital\ Cost = Capital\ Cost \cdot CRF \tag{23}$$

where *Capital Cost* is calculated using an equation above and the Capital Recovery Factor *CRF* is calculated as in Section 1.1.

2.3.2 Operation and Maintenance Cost Equation

The O&M cost is calculated by subtracting the annualized capital cost from the total annual cost.

$$O\&M\ Cost = Total\ Annual\ Cost\ -\ Annualized\ Capital\ Cost \tag{24}$$

where the *Total Annual Cost* and the *Annualized Capital Cost* were calculated previously.

2.4 Equation Type 2b

Equation Type 2b is used to calculate NO_x control costs for natural gas lean burn or clean burn ICE with low emissions combustion (LEC) control technology. LEC control technology is described as retrofit kits that allow engines to operate on extremely lean fuel mixtures to minimize NO_x emissions. The LEC control technology retrofit may include: (1) redesign of cylinder head and pistons to improve mixing (on smaller engines), (2) precombustion chamber (on larger engines), lower cost, simple versions, (3) turbocharger, (4) high energy ignition system, (5) aftercooler, and (6) air-to-fuel ratio controller.

Based on the cost calculations for engines of varying power (hp), Equation Type 2b was developed for the capital cost and annual costs for LEC on natural gas lean burn engines. The development of the controls using Equation Type 2b is discussed in RTI (2014).

2.4.1 Capital and Total Annual Cost Equations

The capital and total annual costs are estimated using the following equations.

$$Capital\ Cost\ = p_1 \cdot e^{(p_2 \cdot DC_{hp})} \tag{25}$$

$$Total\ Annual\ Cost\ = p_3 \cdot e^{(p_4 \cdot DC_{hp})} \tag{26}$$

where

DC_{hp} = design capacity (in horsepower)
p_1 = capital cost multiplier
p_2 = capital cost exponent
p_3 = annual cost multiplier
p_4 = annual cost exponent

The capital and annual cost multipliers and exponents are empirical values specific to control measures. Importantly, this equation type requires the design capacity to be in terms of horsepower, which may necessitate a conversion from the emissions inventory unit of measure. See Section 1.2 for a discussion of this conversion.

The annualized capital cost is then calculated as

$$Annualized\ Capital\ Cost = Capital\ Cost \cdot CRF \tag{27}$$

where *Capital Cost* is calculated using the equation above and the Capital Recovery Factor *CRF* is calculated as in Section 1.1.

2.4.2 Operation and Maintenance Cost Equation

The O&M cost is calculated by subtracting the annualized capital cost from the total annual cost.

$$O\&M\ Cost = Total\ Annual\ Cost\ -\ Annualized\ Capital\ Cost \tag{28}$$

where the *Total Annual Cost* and the *Annualized Capital Cost* were calculated previously.

2.5 Equation Type 2c

Equation Type 2c is used to calculate the cost of NO_x control technologies for internal combustion engines. While controls using this equation type were originally modified in the CMDB to use Equation Type 2, these modifications required converting the engine design capacity from horsepower to MMBtu/hr. Because of reporting errors in emissions inventories, this resulted in unrealistic costs sometimes being estimated. To better limit the application of the cost equations to engines of an appropriate size in horsepower, Equation Type 2c was created and its application was limited to engines less than 1,500 hp. For sources above this threshold, a default cost per ton value is used along with the annual emissions reduction achieved by the applied control measure to calculate the total annual cost of the control measure (see Section 2.12).

The control technologies are:

- Air-to-Fuel Ratio Controller
- SCR

The development of the controls using Equation Type 2c is discussed in RTI (2014). These controls were derived from previous studies combined with vendor quotes.

2.5.1 Capital and Total Annual Cost Equations

The capital and total annual costs are estimated using one of the sets of equations below. If the emissions source does not already have a control listed in the inventory the equations for a new control are used, while if a control is already installed on a source, the equations for an add-on control are used.

<u>New control:</u>

$$Capital\ Cost = p_1 \cdot DC_{hp}^{p_2} + p_9 \tag{29}$$

$$Total\ Annual\ Cost = p_3 \cdot DC_{hp}^{p_4} + p_{10} \tag{30}$$

<u>Add-on control:</u>

$$Capital\ Cost = p_5 \cdot DC_{hp}^{p_6} + p_{11} \tag{31}$$

$$Total\ Annual\ Cost = p_7 \cdot DC_{hp}^{p_8} + p_{12} \tag{32}$$

where

DC_{hp} = design capacity (in horsepower)
p_1 = capital cost multiplier for new control
p_2 = capital cost exponent for new control
p_3 = annual cost multiplier for new control
p_4 = annual cost exponent for new control
p_5 = capital cost multiplier for add-on control

p_6 = capital cost exponent for add-on control
p_7 = annual cost multiplier for add-on control
p_8 = annual cost exponent for add-on control
p_9 = capital cost constant for new control
p_{10} = annual cost constant for new control
p_{11} = capital cost constant for add-on control
p_{12} = annual cost constant for add-on control

The capital and annual cost multipliers, exponents, and constants are empirical values specific to control measures. Some measures may not have capital or annual cost constants, and the functional form can be made linear by setting the exponents equal to 1, which is the case with the CMDB measures currently using this equation type.

The annualized capital cost is then calculated as

$$Annualized\ Capital\ Cost = Capital\ Cost \cdot CRF \tag{33}$$

where *Capital Cost* is calculated using an equation above and the Capital Recovery Factor *CRF* is calculated as in Section 1.1.

2.5.2 Operation and Maintenance Cost Equation

The O&M cost is calculated by subtracting the annualized capital cost from the total annual cost.

$$O\&M\ Cost = Total\ Annual\ Cost\ -\ Annualized\ Capital\ Cost \tag{34}$$

where the *Total Annual Cost* and the *Annualized Capital Cost* were calculated previously.

2.6 Equation Type 8

Equation Type 8 is used to calculate the cost of $PM_{2.5}$, SO_2, and VOC control technologies for a variety of types of industrial sources, as shown in Table 1. This equation type uses the exhaust flowrate at actual stack conditions (F_a) in actual cubic feet per minute (acfm) (see Section 1.2.2 for discussion of flowrate unit conversions).

$PM_{2.5}$ control technologies for Equation Type 8 are:

- Electrostatic Precipitator
- Fabric Filter
- Venturi Scrubber

The SO_2 control technology for Equation Type 8 are:

- Packed Bed Scrubber

VOC control technologies for Equation Type 8 are:
- Carbon Adsorber

- Catalytic Oxidizer
- Regenerative Thermal Oxidizer
- Vapor Recovery Unit

The development of the controls using Equation Type 8 is discussed in several reports. The $PM_{2.5}$ controls are discussed in GDIT (2019), the SO_2 controls are discussed in GDIT (2021), and the VOC controls are discussed in GDIT (2020). Each of these studies used an EPA emissions inventory (2018 for SO_2 and 2016 for $PM_{2.5}$ and VOC) to create model sources representing the typical range of sources for which the controls being developed would be applicable. The capital and O&M cost for each control was then estimated for each model source using either the EPA Control Cost Manual spreadsheets (U.S. EPA, 2017), or in the case of $PM_{2.5}$ the EPA CO$T-AIR spreadsheets (U.S. EPA, 1999b) updated to reflect the methodology described in the current version of the EPA Control Cost Manual (U.S. EPA, 2017). Linear regression was then used with the resulting cost estimates for the model sources to develop cost equations that relate the capital and O&M costs to the flow rate of a source.

2.6.1 Capital and O&M Cost Equations

The capital and O&M costs are estimated using the following equations.

$$Capital\ Cost = p_1 \cdot F_a + p_6 \tag{35}$$

$$O\&M\ Cost = p_2 \cdot F_a + p_7 \tag{36}$$

where
F_a = actual exhaust flowrate (acfm)
p_1 = capital cost multiplier
p_2 = O&M cost multiplier
p_6 = capital cost constant
p_7 = O&M cost constant

The capital and O&M cost multipliers and constants are empirical values specific to control measures. Some measures may not have capital or annual cost constants. Specifically, this equation type was modified in 2020 to add capital and O&M cost constants. For previous measures that used this equation type, those constants will equal 0.

The annualized capital cost is then calculated as

$$Annualized\ Capital\ Cost = Capital\ Cost \cdot CRF \tag{37}$$

where *Capital Cost* is calculated using the equation above and the Capital Recovery Factor *CRF* is calculated as in Section 1.1.

2.6.2 Total Annual Cost Equation

The total annual cost is calculated by adding the annualized capital cost and the O&M cost.

$$Total\ Annual\ Cost\ = Annualized\ Capital\ Cost\ + O\&M\ Cost \tag{38}$$

where *Annualized Capital Cost* and *O&M Cost* were calculated previously.

Total annual cost was modified in 2019 to remove an additional term that was 4% of capital cost. This additional term represented fixed annual charge for taxes, insurance, and administrative costs. These costs are captured in the total annual cost calculation of control measures currently using this equation type.

2.7 Equation Type 12

For a select set of gas-fired process heaters at petroleum refineries, control costs are estimated using stack flowrate and temperature represented by Equation Type 12. Control technologies for Equation Type 12 are:

- Excess O_2 Control
- Selective Catalytic Reduction
- Ultra-Low NO_x Burner

The development of the controls using Equation Type 12 is discussed in U.S. EPA (2015), which relied upon cost information from MACTEC (2005). Control costs are estimated for units that have a positive stack flowrate and temperature value. For sources with missing stack flowrate or temperature, the equations are not used.

2.7.1 Emissions Reduction Equations

In addition to estimating the cost of the control, this equation type does not rely upon a control efficiency specified in the CMDB, but instead calculates the emissions reduction from the application of a control. This calculation uses the exhaust flowrate at standard temperature (F_S) in standard cubic feet per minute (scfm) (see Section 1.2.2 for discussion of flowrate unit conversions). To calculate the emissions reduction, the following calculations are performed.

The concentration of NO_x in stack gas (parts per million by volume [ppmv]) is calculated as

$$C_{NOx} = \frac{VFR_{NOx}}{F_S} \cdot 1{,}000{,}000 \tag{39}$$

where
F_S = exhaust flowrate at standard temperature (scfm)
VFR_{NOx} = Volumetric Flow Rate (ft^3/minute) of NO_x

The Volumetric Flow Rate (ft^3/minute) of NO_x (VFR_{NOx}) in the stack gas given the inventory emissions of NO_x is calculated as

$$VFR_{NOx} = E_{NOx} \cdot 2{,}000 \cdot \left(\frac{1}{46.0}\right) \cdot \left(\frac{1}{Op_{Hrs}}\right)\left(\frac{1}{60}\right) \cdot 379.704 \tag{40}$$

where

E_{NOx} = Annual NO_x emissions (tons/year)
2,000 = lbs/ton
46.0 = molecular weight of NO_2 (grams/mol)
Op_{Hrs} = annual hours of operation
60 = minutes/hour
379.704 = Volume of 1 mol NO_2 under standard conditions (ft^3/mol)

Using the calculated value for C_{NOx} and the outlet concentration specified for the control measure CMC_{NOx}, which is stored in the CMDB properties table, the percent reduction in NO_x associated with the control measure R_{NOx} is calculated as

$$R_{NOx} = \frac{C_{NOx} - CMC_{NOx}}{C_{NOx}}. \tag{41}$$

The reduction in NO_x emissions due to the application of the control measure is then calculated as

$$ER_{NOx} = E_{NOx} \cdot R_{NOx} \tag{42}$$

where E_{NOx} and R_{NOx} are as previously defined.

2.7.2 Capital and O&M Cost Equations

The capital and O&M costs are estimated using the following equations.

$$Capital\ Cost = (p_1 + p_2) \cdot \left(\frac{F_s}{150{,}000}\right)^{0.6} \tag{43}$$

$$O\&M\ Cost = (p_3 + p_4) \cdot \left(\frac{F_s}{150{,}000}\right) \tag{44}$$

where

F_S = exhaust flowrate at standard temperature (scfm)
p_1 = fixed capital cost constant
p_2 = variable capital cost constant
p_3 = fixed O&M cost constant
p_4 = variable O&M cost constant

The capital and O&M cost multipliers and constants are empirical values specific to control measures. Some measures may not have capital or annual cost constants.

The annualized capital cost is then calculated as

$$Annualized\ Capital\ Cost = Capital\ Cost \cdot CRF \tag{45}$$

where *Capital Cost* is calculated using the equation above and the Capital Recovery Factor *CRF* is calculated as in Section 1.1.

2.7.3 Total Annual Cost Equation

The total annual cost is calculated by adding the annualized capital cost and the O&M cost.

$$Total\ Annual\ Cost\ = Annualized\ Capital\ Cost\ + O\&M\ Cost \tag{46}$$

where *Annualized Capital Cost* and *O&M Cost* were calculated previously.

2.8 Equation Type 13

Equation Type 13 is used to calculate NO_x control costs for Industrial, Commercial, and Institutional (ICI) boilers. The control technologies are:

- Flue Gas Recirculation
- Low NO_x Burner
- Low NO_x Burner and Flue Gas Recirculation
- Low NO_x Burner and Selective Non-Catalytic Reduction
- Ultra Low NO_x Burner
- Ultra Low NO_x Burner and Selective Catalytic Reduction
- Ultra Low NO_x Burner and Selective Non-Catalytic Reduction

Equation Type 13 was derived based on a review of previous ICI boiler control costs calculations and outputs from the EPA Coal Utility Environmental Cost (CUECost) model (U.S. EPA, 1999a) and a study of control options for ICI boilers conducted by the Ozone Transport Commission and Lake Michigan Air Directors Consortium (OTC-LADCO, 2010). The costs were generated for control devices on the five boiler sizes (i.e., 100, 200, 300, 400, and 500 MMBtu/hour) in CUECost and the 250 MMBtu/hour boiler in OTC-LADCO (2010). Although control device costs do not rise in strict proportion to size, the plotted results demonstrated that control costs versus boiler size showed a power law relationship, which was used to derive Equation Type 13. More details about the development of the equations can be found in ERG (2010).

2.8.1 Capital and O&M Cost Equations

ERG (2010) found that there were not cost savings from combining different ICI boiler control technologies. As a result, control costs for each technology can be treated as additive when multiple control options are available. The capital and O&M costs are estimated using the following equations.

$$Capital\ Cost = p_1 \cdot DC_{MMBtu/hr}^{p_2} + p_3 \cdot DC_{MMBtu/hr}^{p_4} \tag{47}$$

$$O\&M\ Cost = p_5 + p_6 \cdot DC_{MMBtu/hr}^{p_7} + p_8 \cdot DC_{MMBtu/hr}^{p_9} + p_{10} \cdot \frac{F_a}{60} + p_{11} \cdot E \tag{48}$$

where

$DC_{MMBtu/hr}$ = design capacity (in MMBtu/hr)

F_a = actual exhaust flowrate (acfm)

E = emissions (ton/year)

60 = minutes/hour
p_1 = capital cost multiplier (control #1)
p_2 = capital cost exponent (control #1)
p_3 = capital cost multiplier (control #2 if applicable)
p_4 = capital cost exponent (control #2 if applicable)
p_5 = O&M cost constant
p_6 = O&M cost multiplier (control #1)
p_7 = O&M cost exponent (control #1)
p_8 = O&M cost multiplier (control #2 if applicable)
p_9 = O&M cost exponent (control #2 if applicable)
p_{10} = flowrate multiplier
P_{11} = emissions multiplier

The capital cost and O&M cost multipliers and exponents are empirical values that vary by control technology.

The annualized capital cost is then calculated as

$$Annualized\ Capital\ Cost = Capital\ Cost \cdot CRF \tag{49}$$

where *Capital Cost* is calculated using an equation above and the Capital Recovery Factor *CRF* is calculated as in Section 1.1.

2.8.2 Total Annual Cost Equation

The total annual cost is calculated by adding the annualized capital cost and the O&M cost.

$$Total\ Annual\ Cost\ = Annualized\ Capital\ Cost\ + O\&M\ Cost \tag{50}$$

where *Annualized Capital Cost* and *O&M Cost* were calculated previously.

2.9 Equation Type 18

Equation Type 18 is used to calculate control costs for using an increased caustic injection rate for existing dry injection control on various external combustion boilers and industrial processes. No new capital investment is required.

The development of this equation type is discussed in ERG (2015). This equation type uses both the exhaust flowrate at standard temperature (F_s) in standard cubic feet per minute (scfm) and at standard temperature on a dry basis (F_d) in dry standard cubic feet per minute (dscfm), depending on the individual equation (see Section 1.2 for discussion of flowrate unit conversions). While the general forms of the flowrate unit conversions are presented in Section 1.2, for this equation type F_d is calculated as

$$F_d = (F_a)\left(\frac{460+68}{460+T}\right)\left(1-\frac{p_1}{100}\right) \tag{51}$$

where
F_a = Actual exhaust flowrate (acfm)
T = Stack gas temperature (˚F) from the emissions inventory
p_1 = Stack gas moisture content (%)

The equation also requires the calculation of the concentration of SO_2 in the exhaust gas, which is discussed in the next section.

2.9.1 Concentration of SO_2 in outlet gas

The concentration of SO_2 in stack gas (dry parts per million by volume [ppmvd]) is calculated as

$$C_{SO2} = \frac{VFR_{SO2}}{F_S} \cdot 1{,}000{,}000 \tag{52}$$

where
F_S = exhaust flowrate at standard temperature (scfm)
VFR_{SO2} = Volumetric Flow Rate (ft^3/minute) of SO_2

The Volumetric Flow Rate (ft^3/minute) of SO_2 (VFR_{SO2}) in the stack gas given the inventory emissions of SO_2 is calculated as

$$VFR_{SO2} = E_{SO2} \cdot 2{,}000 \cdot \left(\frac{1}{64.06}\right) \cdot \left(\frac{1}{Op_{Hrs}}\right)\left(\frac{1}{60}\right) \cdot 379.704 \tag{53}$$

where
E_{SO2} = Annual SO_2 emissions (tons/year)
2,000 = lbs/ton
64.06 = molecular weight of SO_2 (grams/mol)
Op_{Hrs} = annual hours of operation
60 = minutes/hour
379.704 = Volume of 1 mol SO_2 under standard conditions (ft^3/mol)

2.9.2 Capital and Total Annual Cost Equations

As previously noted, this equation requires an existing dry injection control system, so there is no additional capital investment. Therefore, the capital and total annual costs are estimated using the following equations.

$$Capital\ Cost = 0 \tag{54}$$

$$Total\ Annual\ Cost\ =\ (0.00000387)(C_{SO2})(F_d)(Op_{Hrs}) \tag{55}$$

where
C_{SO2} = Concentration of SO_2 in stack gas, dry parts per million by volume (ppmvd)
F_d = Exhaust flowrate at standard temperature on a dry basis (dscfm)
Op_{Hrs} = annual hours of operation

2.10 Equation Type 20

Equation Type 20 is used to calculate control costs for some NO_x controls on coal-, gas-, and oil-fired Industrial, Commercial, and Institutional (ICI) boilers and some SO_2 controls on gas- and oil-fired ICI boilers.

NO_x control technologies for Equation Type 20 are:

- Selective Catalytic Reduction
- Selective Non-Catalytic Reduction

SO_2 control technologies for Equation Type 20 are:

- Dry Scrubber
- Wet Scrubber

The development of this equation type is discussed in ERG (2019). This equation type uses the design capacity from the input emissions inventory, converted from emissions inventory units to the unit (MMBtu/hour) required by the cost equations (see Section 1.2 for a discussion of this conversion).

2.10.1 Capital and O&M Cost Equations

The capital and O&M costs are estimated using the following equations.

$$Capital\ Cost = p_1 \cdot DC_{MMBtu/hr} \tag{56}$$

$$O\&M\ Cost = p_2 \cdot DC_{MMBtu/hr} \tag{57}$$

where
$DC_{MMBtu/hr}$ = design capacity (in MMBtu/hr)
p_1= capital cost multiplier
p_2 = O&M cost multiplier

The capital and O&M cost multipliers are empirical values specific to control measures.

The annualized capital cost is then calculated as

$$Annualized\ Capital\ Cost = Capital\ Cost \cdot CRF \tag{58}$$

where *Capital Cost* is calculated using an equation above and the Capital Recovery Factor *CRF* is calculated as in Section 1.1.

2.10.2 Total Annual Cost Equation

The total annual cost is calculated by adding the annualized capital cost and the O&M cost.

$$Total\ Annual\ Cost\ = Annualized\ Capital\ Cost\ + O\&M\ Cost \tag{59}$$

where *Annualized Capital Cost* and *O&M Cost* were calculated previously.

2.11 Equation Type 21

Equation Type 21 is used to calculate control costs for some SO_2 controls on coal-fired Industrial, Commercial, and Institutional (ICI) boilers.

SO_2 control technologies for Equation Type 21 are:

- Dry Scrubber
- Wet Scrubber

The development of this equation type is discussed in GDIT (2021). This equation type uses the design capacity from the input emissions inventory, converted from emissions inventory units to the unit (MW) required by the cost equations (see Section 1.2 for a discussion of this conversion).

2.11.1 Capital and O&M Cost Equations

The capital and O&M costs are estimated using the following equations.

$$Capital\ Cost = p_1 \cdot DC_{MW} + p_3 \tag{60}$$

$$O\&M\ Cost = p_2 \cdot DC_{MW} + p_4 \tag{61}$$

where
DC_{MW} = design capacity (in megawatts)
p_1 = capital cost multiplier
p_2= O&M cost multiplier
p_3 = capital cost constant
p_4= O&M cost constant

The capital and annual cost multipliers and constants are empirical values specific to control measures.

The annualized capital cost is then calculated as

$$Annualized\ Capital\ Cost = Capital\ Cost \cdot CRF \tag{62}$$

where *Capital Cost* is calculated using an equation above and the Capital Recovery Factor *CRF* is calculated as in Section 1.1.

2.11.2 Total Annual Cost Equation

The total annual cost is calculated by adding the annualized capital cost and the O&M cost.

$$Total\ Annual\ Cost\ = Annualized\ Capital\ Cost\ + O\&M\ Cost \tag{63}$$

where *Annualized Capital Cost* and *O&M Cost* were calculated previously.

2.12 Cost per Ton Calculations

Throughout this document, specific cases have been noted when the control cost is calculated using a default cost per ton value instead of equations because a source exceeds a size constraint. A default cost per ton value is also used when the inventory lacks the information needed to estimate an equation. In these cases, the default control efficiency associated with a control is used to estimate the emissions reduction achieved by the applied control measure. Then, a default cost per ton value is used along with the estimated emissions reduction to calculate the total annual cost of the control measure using the following equation.

$$Total\ Annual\ Cost\ = Emissions\ Reduction \cdot Default\ Cost\ per\ Ton \tag{64}$$

where
Emissions Reduction = calculated by CoST (tons/year)
Default Cost per Ton = an empirical value based on the specific control measure

Some caveats are in order regarding the use of default cost per ton values. Typically, default cost per ton values are developed using data from large, uncontrolled sources. If these values are then applied to emissions reductions from replacement controls on sources that are already controlled, the resulting annual cost estimates may not capture the full cost of switching or adding controls. Likewise, for sources with relatively small levels of emissions due either to their nature or the presence of a control that is not indicated in the emissions inventory, the resulting annual cost estimates may understate the true total cost of the control.

Similarly, it should be noted that the capital cost and O&M cost estimates may be inaccurate when default cost per ton values are used. In a CoST run, after the *Total Annual Cost* is calculated using the default cost per ton value, the following steps occur: 1) the capital to annual cost ratio (if specified) is multiplied by the *Total Annual Cost* to calculate the *Capital Cost*, 2) *the Capital Cost* is multiplied by a capital recovery factor that is estimated using the interest rate for the CoST run and the equipment life for the control to calculate the *Annualized Capital Cost*, and 3) the *Annualized Capital Cost* is subtracted from the *Total Annual Cost* to calculate the *O&M Cost*. It is important to note that the capital to annual cost ratio for a particular control is associated with a specific interest rate that may not match the interest rate specified for the CoST run, which would make all of the calculations beyond the initial *Total Annual Cost* calculation invalid.

3 Summary of Equations in CoST

The preceding sections presented a detailed discussion of the equation types in CoST. These discussions are summarized in a quick reference format in Table 2, which includes a brief description of the control technologies and the types of sources to which they apply, as well as the equations and associated references. Table 3 indicates where in each reference the parameters for each equation can be found. In some cases, it is noted that they have been revised. These revisions, along with any code and data used to calculate them, are available from EPA upon request.

Table 2. Summary of Equation Types in CoST

Equation Type (Pollutants)	Source Group	Control Technologies	Equation	References
1 (NO_x, $PM_{2.5}$, SO_2)	EGU Boilers	NO_x (9 measures): • Low NO_x Burner • Low NO_x Burner and Overfire Air • Low NO_x Coal-and-Air Nozzles with Close-Coupled Overfire Air • Low NO_x Coal-and-Air Nozzles with Close-Coupled and Separated Overfire Air • Low NO_x Coal-and-Air Nozzles with Separated Overfire Air • Selective Catalytic Reduction • Selective Non-Catalytic Reduction $PM_{2.5}$ (1 measure): • Fabric Filter (Pulse Jet Type) SO_2 (2 measures): • Lime Spray Dryer • Limestone Forced Oxidation	$S = \left(\frac{p_4}{DC_{MW}}\right)^{p_5}$ $Capital\ Cost = p_1 \cdot DC_{MW} \cdot S \cdot 1{,}000$ $Fixed\ O\&M = p_2 \cdot DC_{MW} \cdot S \cdot 1{,}000$ $Variable\ O\&M = p_3 \cdot DC_{MW} \cdot p_6 \cdot 8{,}760$ $O\&M\ Cost = Fixed\ O\&M + Variable\ O\&M$ $Annualized\ Capital\ Cost = Capital\ Cost \cdot CRF$ $Total\ Annual\ Cost = Annualized\ Capital\ Cost + O\&M\ Cost$ where S = scaling factor DC_{MW} = design capacity (in megawatts) p_1 = capital cost multiplier p_2 = fixed O&M cost multiplier p_3 = variable O&M cost multiplier p_4 = scaling factor model size p_5 = scaling factor exponent p_6 = capacity factor	U.S. EPA, 2013

Equation Type (Pollutants)	Source Group	Control Technologies	Equation	References
2 (NO_x)	Gas Turbines (design capacity ≤ 2,000 MMBtu/hr)	<u>NO_x (11 measures):</u> • Catalytic Combustion • Dry Low NO_x Combustion • EMx • EMx and Dry Low NO_x Combustion • EMx and Water Injection • Low NO_x Burner • Selective Catalytic Reduction and Dry Low NO_x Combustion • Selective Catalytic Reduction and Steam Injection • Selective Catalytic Reduction and Water Injection • Steam Injection • Water Injection	<u>New control:</u> $Capital\ Cost = p_1 \cdot DC_{MMBtu/hr}^{p_2} + p_9$ $Total\ Annual\ Cost = p_3 \cdot DC_{MMBtu/hr}^{p_4} + p_{10}$ <u>Add-on control:</u> $Capital\ Cost = p_5 \cdot DC_{MMBtu/hr}^{p_6} + p_{11}$ $Total\ Annual\ Cost = p_7 \cdot DC_{MMBtu/hr}^{p_8} + p_{12}$ $Annualized\ Capital\ Cost = Capital\ Cost \cdot CRF$ $O\&M\ Cost = Total\ Annual\ Cost\ -\ Annualized\ Capital\ Cost$ where $DC_{MMBtu/hr}$ = design capacity (in MMBtu/hr) p_1 = capital cost multiplier for new control p_2 = capital cost exponent for new control p_3 = annual cost multiplier for new control p_4 = annual cost exponent for new control p_5 = capital cost multiplier for add-on control p_6 = capital cost exponent for add-on control p_7 = annual cost multiplier for add-on control p_8 = annual cost exponent for add-on control p_9 = capital cost constant for new control p_{10} = annual cost constant for new control p_{11} = capital cost constant for add-on control p_{12} = annual cost constant for add-on control	RTI, 2014

Equation Type (Pollutants)	Source Group	Control Technologies	Equation	References
2a (NO_x)	Glass Manufacturing (design capacity ≤ 2,000 MMBtu/hr)	<u>NO_x (4 measures):</u> • Low NO_x Burner • Selective Catalytic Reduction	<u>New control:</u> $Capital\ Cost = p_1 \cdot \left(\frac{ER}{365}\right)^{p_2} + p_9$ $Total\ Annual\ Cost = p_3 \cdot \left(\frac{ER}{365}\right)^{p_4} + p_{10}$ <u>Add-on control:</u> $Capital\ Cost = p_5 \cdot \left(\frac{ER}{365}\right)^{p_6} + p_{11}$ $Total\ Annual\ Cost = p_7 \cdot \left(\frac{ER}{365}\right)^{p_8} + p_{12}$ $Annualized\ Capital\ Cost = Capital\ Cost \cdot CRF$ $O\&M\ Cost = Total\ Annual\ Cost - Annualized\ Capital\ Cost$ where ER = emissions reduction from control p_1 = capital cost multiplier for new control p_2 = capital cost exponent for new control p_3 = annual cost multiplier for new control p_4 = annual cost exponent for new control p_5 = capital cost multiplier for add-on control p_6 = capital cost exponent for add-on control p_7 = annual cost multiplier for add-on control p_8 = annual cost exponent for add-on control p_9 = capital cost constant for new control p_{10} = annual cost constant for new control p_{11} = capital cost constant for add-on control p_{12} = annual cost constant for add-on control	RTI, 2014

Equation Type (Pollutants)	Source Group	Control Technologies	Equation	References
2b (NO_x)	Natural Gas Internal Combustion Engines (design capacity ≤ 1,500 hp)	<u>NO_x (1 measure):</u> • Low Emission Combustion	$Capital\ Cost\ = p_1 \cdot e^{(p_2 \cdot DC_{hp})}$ $Total\ Annual\ Cost\ = p_3 \cdot e^{(p_4 \cdot DC_{hp})}$ $Annualized\ Capital\ Cost = Capital\ Cost \cdot CRF$ $O\&M\ Cost = Total\ Annual\ Cost - Annualized\ Capital\ Cost$ where DC_{hp} = design capacity (in horsepower) p_1 = capital cost multiplier p_2 = capital cost exponent p_3 = annual cost multiplier p_4 = annual cost exponent	RTI, 2014
2c (NO_x)	Natural Gas Internal Combustion Engines (design capacity < 1,500 hp)	<u>NO_x (2 measures):</u> • Air-to-Fuel Ratio Controller • Selective Catalytic Reduction	<u>New control:</u> $Capital\ Cost = p_1 \cdot DC_{hp}^{p_2} + p_9$ $Total\ Annual\ Cost = p_3 \cdot DC_{hp}^{p_4} + p_{10}$ <u>Add-on control:</u> $Capital\ Cost = p_5 \cdot DC_{hp}^{p_6} + p_{11}$ $Total\ Annual\ Cost = p_7 \cdot DC_{hp}^{p_8} + p_{12}$ $Annualized\ Capital\ Cost = Capital\ Cost \cdot CRF$ $O\&M\ Cost = Total\ Annual\ Cost - Annualized\ Capital\ Cost$ where DC_{HP} = design capacity (in horsepower) p_1 = capital cost multiplier for new control p_2 = capital cost exponent for new control p_3 = annual cost multiplier for new control p_4 = annual cost exponent for new control p_5 = capital cost multiplier for add-on control p_6 = capital cost exponent for add-on control p_7 = annual cost multiplier for add-on control p_8 = annual cost exponent for add-on control p_9 = capital cost constant for new control p_{10} = annual cost constant for new control p_{11} = capital cost constant for add-on control p_{12} = annual cost constant for add-on control	RTI, 2014

Equation Type (Pollutants)	Source Group	Control Technologies	Equation	References
8 ($PM_{2.5}$, SO_2, VOC)	ICI Boilers, Process Heaters, Space Heaters, and Non-EGU Industrial Processes (see Table 1 for more details)	$PM_{2.5}$ (12 measures): • Electrostatic Precipitator (All Types) • Fabric Filter (All Types) • Venturi Scrubber SO_2 (1 measure): • Packed Bed Scrubber VOC (4 measures): • Carbon Adsorber • Catalytic Oxidizer • Regenerative Thermal Oxidizer • Vapor Recovery Unit	$Capital\ Cost = p_1 \cdot F_a + p_6$ $O\&M\ Cost = p_2 \cdot F_a + p_7$ $Annualized\ Capital\ Cost = Capital\ Cost \cdot CRF$ $Total\ Annual\ Cost = Annualized\ Capital\ Cost + O\&M\ Cost$ where F_a = actual exhaust flowrate (acfm) p_1 = capital cost multiplier p_2 = O&M cost multiplier p_6 = capital cost constant p_7 = O&M cost constant	GDIT, 2019 GDIT, 2020 GDIT, 2021
12 (NO_x)	Petroleum Refinery Gas-Fired Process Heaters	NO_x (4 measures): • Excess O_2 Control • Selective Catalytic Reduction • Ultra-Low NO_x Burner	$Capital\ Cost = (p_1 + p_2) \times \left(\frac{F_s}{150{,}000}\right)^{0.6}$ $O\&M\ Cost = (p_3 + p_4) \times \left(\frac{F_s}{150{,}000}\right)$ $Annualized\ Capital\ Cost = Capital\ Cost \cdot CRF$ $Total\ Annual\ Cost = Annualized\ Capital\ Cost + O\&M\ Cost$ where F_S = exhaust flowrate at standard temperature (scfm) p_1 = fixed capital cost constant p_2 = variable capital cost constant p_3 = fixed O&M cost constant p_4 = variable O&M cost constant	U.S. EPA, 2015 MACTEC, 2005

Equation Type (Pollutants)	Source Group	Control Technologies	Equation	References
13 (NO_x)	ICI Boilers and Catalytic Cracking Units	<u>NO_x (13 measures):</u> • Flue Gas Recirculation • Low NO_x Burner • Low NO_x Burner and Flue Gas Recirculation • Low NO_x Burner and Selective Non-Catalytic Reduction • Ultra-Low NO_x Burner • Ultra-Low NO_x Burner and Selective Catalytic Reduction • Ultra-Low NO_x Burner and Selective Non-Catalytic Reduction	$Capital\ Cost = p_1 \cdot DC_{MMBtu/hr}^{p_2} + p_3 \cdot DC_{MMBtu/hr}^{p_4}$ $O\&M\ Cost = p_5 + p_6 \cdot DC_{MMBtu/hr}^{p_7} + p_8 \cdot DC_{MMBtu/hr}^{p_9} + p_{10} \cdot \frac{F_a}{60} + p_{11} \cdot E$ $Annualized\ Capital\ Cost = Capital\ Cost \cdot CRF$ $Total\ Annual\ Cost = Annualized\ Capital\ Cost + O\&M\ Cost$ where $DC_{MMBtu/hr}$ = design capacity (in MMBtu/hr) F_a = actual exhaust flowrate (acfm) E = emissions (ton/year) p_1 = capital cost multiplier (control #1) p_2 = capital cost exponent (control #1) p_3 = capital cost multiplier (control #2 if applicable) p_4 = capital cost exponent (control #2 if applicable) p_5 = O&M cost constant p_6 = O&M cost multiplier (control #1) p_7 = O&M cost exponent (control #1) p_8 = O&M cost multiplier (control #2 if applicable) p_9 = O&M cost exponent (control #2 if applicable) p_{10} = flowrate multiplier P_{11} = emissions multiplier	ERG, 2010

Equation Type (Pollutants)	Source Group	Control Technologies	Equation	References
18 (SO_2)	Industrial Boilers and Process Heaters with an Existing Dry Injection Control	<u>SO_2 (9 measures):</u> • Increased Caustic Injection Rate for Existing Dry Injection Control	$Capital\ Cost = 0$ $Total\ Annual\ Cost\ =\ (0.00000387)(C_{SO2})(F_d)(Op_{hrs})$ where C_{SO2} = Concentration of SO2 in stack gas, dry parts per million by volume (ppmvd) F_d = Exhaust flowrate at standard temperature on a dry basis (dscfm) Op_{hrs} = annual hours of operation C_{SO2} is calculated as $C_{SO2} = \frac{VFR_{SO2}}{F_S} \cdot 1{,}000{,}000$ where F_S = exhaust flowrate at standard temperature (scfm) VFR_{SO2} = Volumetric Flow Rate (ft3/minute) of SO2, calculated as $VFR_{SO2} = E_{SO2} \cdot 2{,}000 \cdot \left(\frac{1}{64.06}\right) \cdot \left(\frac{1}{Op_{hrs}}\right)\left(\frac{1}{60}\right) \cdot 379.704$ where E_{SO2} = SO2 emissions (tons/year) 64.06 = molecular weight of SO2 (grams/mol) 379.704 = Volume of 1 mol SO2 under standard conditions (ft3/mol)	ERG, 2015
20 (NO_x, SO_2)	ICI Boilers, Catalytic Cracking Units, Process Heaters, and Space Heaters	<u>NO_x (6 measures)</u>: • Selective Catalytic Reduction (coal-, gas-, oil-fired) • Selective Non-Catalytic Reduction (coal-, gas-, oil-fired) <u>SO_2 (4 measures):</u> • Dry Scrubber (oil-, gas-fired) • Wet Scrubber (gas-fired)	$Capital\ Cost = p_1 \cdot DC_{MMBtu/hr}$ $O\&M\ Cost = p_2 \cdot DC_{MMBtu/hr}$ $Annualized\ Capital\ Cost = Capital\ Cost \cdot CRF$ $Total\ Annual\ Cost = Annualized\ Capital\ Cost + O\&M\ Cost$ where $DC_{MMBtu/hr}$ = design capacity (in MMBtu/hr) p_1= capital cost multiplier p_2 = O&M cost multiplier	ERG, 2019

Equation Type (Pollutants)	Source Group	Control Technologies	Equation	References
21 (SO_2)	ICI Boilers	<u>SO_2 (4 measures):</u> • Dry Scrubber (coal-fired) • Wet Scrubber (coal-fired)	$Capital\ Cost = p_1 \cdot DC_{MW} + p_3$ $O\&M\ Cost = p_2 \cdot DC_{MW} + p_4$ $Annualized\ Capital\ Cost = Capital\ Cost \cdot CRF$ $Total\ Annual\ Cost = Annualized\ Capital\ Cost + O\&M\ Cost$ where DC_{MW} = design capacity (in megawatts) p_1 = capital cost multiplier p_2= O&M cost multiplier p_3 = capital cost constant p_4= O&M cost constant	GDIT, 2021

Note: For each equation type, the number of control measures in the 4/28/2023 version of the CMDB is indicated for each pollutant. It should be noted that this count does not always match the number of control measure abbreviations for that equation type. Some control measure abbreviations (e.g., NSCR_UBCT1, NSCR_UBCT2, NSCR_UBCT3, NSCR_UBCT4, and NSCR_UBCT5) are the same control technology applied to the same types of sources but reflecting a capacity constraint. Likewise, other control abbreviations (e.g., PESPIPSIZE1, PESPIPSIZE5, and PESPIPSIZE10) are the same control technology but applied to different SCCs based on the SCCs' average particle sizes. For the purpose of these counts, these groups of control measure abbreviations are each considered a single control measure.

Table 3. Equation Parameter Location(s) in References

Equation Type	Pollutant	Control Technology	Control Measure Abbreviation(s)	Equation Parameter Location(s) in Reference
Type 1	NO_x	Low NO_x Burner	NLNBUUBCW	U.S. EPA, 2013 (Table 5-4, p.5-5)
		Low NO_x Burner and Overfire Air	NLNBOUBCW	U.S. EPA, 2013 (Table 5-4, p.5-5)
		Low NO_x Coal-and-Air Nozzles with Close-Coupled Overfire Air	NLNC1UBCT	U.S. EPA, 2013 (Table 5-4, p.5-5)
		Low NO_x Coal-and-Air Nozzles with Close-Coupled and Separated Overfire Air	NLNC3UBCT	U.S. EPA, 2013 (Table 5-4, p.5-5)
		Low NO_x Coal-and-Air Nozzles with Separated Overfire Air	NLNC2UBCT	U.S. EPA, 2013 (Table 5-4, p.5-5)
		Selective Catalytic Reduction	NSCR_UBCT1 NSCR_UBCT2 NSCR_UBCT3 NSCR_UBCT4 NSCR_UBCT5 NSCR_UBOT NSCR_UBOW	U.S. EPA, 2013 (Table 5-6, p.5-7 and Table 5-7, p.5-8)
		Selective Non-Catalytic Reduction	NSNCRUBCT1 NSNCRUBCT2 NSNCRUBCT3 NSNCRUBCT4 NSNCRUBCT5	U.S. EPA, 2013 (Table 5-6, p.5-7)
	$PM_{2.5}$	Fabric Filter	PFFPJUBC1 PFFPJUBC2 PFFPJUBC3 PFFPJUBC4 PFFPJUBC5	U.S. EPA, 2013 (Table 5-18, p.5-30)
	SO_2	Lime Spray Dryer	SLSDUBC1 SLSDUBC2 SLSDUBC3 SLSDUBC4 SLSDUBC5 SLSDUBC6	U.S. EPA, 2013 (Table 5-3, p.5-4)

Equation Type	Pollutant	Control Technology	Control Measure Abbreviation(s)	Equation Parameter Location(s) in Reference
Type 1 (cont.)	SO_2 (cont.)	Limestone Forced Oxidation	SLSFOUBC1 SLSFOUBC2 SLSFOUBC3 SLSFOUBC4 SLSFOUBC5	U.S. EPA, 2013 (Table 5-3, p.5-4)
Type 2	NO_x	Catalytic Combustion	NCATCGTNG	RTI, 2014 (Section 3.2.1, p.3-4)
		Dry Low NO_x Combustion	NDLNCGTNG	RTI, 2014 (Section 3.3.3, p.3-13)
		EMx	NEMXGTNG	ERG, 2017 (Section 2, p.2)
		EMx and Dry Low NO_x Combustion	NEMXDGTNG	RTI, 2014 (Section 3.2.3, p.3-9)
		EMx and Water Injection	NEMXWGTNG	RTI, 2014 (Section 3.2.2, p.3-7)
		Low NO_x Burner	NLNBUGTNG	Pechan, 1998 (Table III-3, p.19)
		Selective Catalytic Reduction and Dry Low NO_x Combustion	NSCRDGTNG	RTI, 2014 (Section 3.3.6, p.3-19)
		Selective Catalytic Reduction and Steam Injection	NSCRSGTNG	RTI, 2014 (Section 3.3.5, p.3-17)
		Selective Catalytic Reduction and Water Injection	NSCRWGTNG	RTI, 2014 (Section 3.3.4, p.3-15)
		Steam Injection	NSTINGTNG	RTI, 2014 (Section 3.3.2, p.3-12)
		Water Injection	NWTINGTNG	RTI, 2014 (Section 3.3.1, p.3-11)
Type 2a	NO_x	Low NO_x Burner	NLNBUGMCN NLNBUGMFT	Original: RTI, 2014 (Section 4.4, p.4-3) Revised: U.S. EPA, 2023 (Table 7, p.12)
		Selective Catalytic Reduction	NSCRGMCN NSCRGMFT	Original: RTI, 2014 (Section 4.4, p.4-4) Revised: U.S. EPA, 2023 (Table 7, p.12)
Type 2b	NO_x	Low Emission Combustion	NLECICENG	RTI, 2014 (Section 5.3, p.5-5)
Type 2c	NO_x	Air-to-Fuel Ratio Controller	NAFRCICENG	Original: RTI, 2014 (Section 5.6, p.5-10) Revised: U.S. EPA, 2023 (Table 9, p.14)
		Selective Catalytic Reduction	NSCRICE4SNG	RTI, 2014 (Section 5.7, p.5-12)
Type 8	$PM_{2.5}$	Electrostatic Precipitator	PESPICICOAL PESPICIGAS PESPICIWOOD PESPIPSIZE1 PESPIPSIZE10 PESPIPSIZE5	Original: GDIT, 2019 (Supplemental tables) Revised: U.S. EPA, 2023 (Table 3, p.8)

Equation Type	Pollutant	Control Technology	Control Measure Abbreviation(s)	Equation Parameter Location(s) in Reference
Type 8 (cont.)	$PM_{2.5}$ (cont.)	Fabric Filter	PFFICICOAL PFFICIGAS PFFICIWOOD PFFIPSIZE1 PFFIPSIZE10 PFFIPSIZE5	Original: GDIT, 2019 (Supplemental tables) Revised: U.S. EPA, 2023 (Table 3, p.8)
		Venturi Scrubber	PVSICICOAL PVSICIGAS PVSICIWOOD PVSIPSIZE1 PVSIPSIZE10 PVSIPSIZE5	Original: GDIT, 2019 (Supplemental tables) Revised: U.S. EPA, 2023 (Table 3, p.8)
	SO_2	Packed Bed Scrubber	SPBSNONEGU	Original: GDIT, 2019 (Supplemental tables) Revised: U.S. EPA, 2023 (Table 5, p.11)
	VOC	Carbon Adsorber	VCAGENVOC	GDIT, 2020 (Figures 10 and 11, p.18)
		Catalytic Oxidizer	VCOXGENVOC	GDIT, 2020 (Figures 8 and 9, p.17)
		Regenerative Thermal Oxidizer	VRTOGENVOC	GDIT, 2020 (Figures 6 and 7, p.16)
		Vapor Recovery Unit	VVRUGENVOC	GDIT, 2020 (Figures 12 and 13, p.19)
Type 12	NO_x	Excess O_2 Control	NPRGPHEO2C	U.S. EPA, 2015 (p.6)
		Selective Catalytic Reduction	NPRGPHSC95 NPRGPHSCR	U.S. EPA, 2015 (p.6)
		Ultra-Low NO_x Burner	NPRGPHULNB	U.S. EPA, 2015 (p.6)
Type 13	NO_x	Flue Gas Recirculation	NBFIBG NBFIBO	ERG, 2010 (Table 4, p.5 and Table 7A, p.7)
		Low NO_x Burner	NLNBIBO NLNBUIBCW	ERG, 2010 (Table 4, p.5 and Table 7A, p.7)
		Low NO_x Burner and Flue Gas Recirculation	NLNBFIBG NLNBFIBO	ERG, 2010 (Table 4, p.5 and Table 7A, p.7)
		Low NO_x Burner and Selective Non-Catalytic Reduction	NLNSNCRIBG NLNSNCRIBO	ERG, 2010 (Table 4, p.5 and Table 7A, p.7)
		Ultra-Low NO_x Burner	NLNBUIBG	ERG, 2010 (Table 4, p.5 and Table 7A, p.7)
		Ultra-Low NO_x Burner and Selective Catalytic Reduction	NLNSCRIBCW NLNSCRIBG NLNSCRIBO	ERG, 2010 (Table 4, p.5 and Table 7A, p.7)

Equation Type	Pollutant	Control Technology	Control Measure Abbreviation(s)	Equation Parameter Location(s) in Reference
Type 13 (cont.)	NO_x (cont.)	Ultra-Low NO_x Burner and Selective Non-Catalytic Reduction	NLNSNCRIBCW	ERG, 2010 (Table 4, p.5 and Table 7A, p.7)
Type 18	SO_2	Increased Caustic Injection Rate for Existing Dry Injection Control	SICIRIBBC SICIRIBDB SICIRIBDO SICIRIBGF SICIRIBOLF SICIRIBOSF SICIRIBRO SICIRIBSC SICIRIBWB	ERG, 2015 (Appendix B-10, p.B-21 and Table 19, p.20)
Type 20	NO_x	Selective Catalytic Reduction	NSCRICBC NSCRICBG NSCRICBO	Original: ERG, 2019 (Section 5, p.11) Revised: U.S. EPA, 2023 (Table 1, p.4)
		Selective Non-Catalytic Reduction	NSNCRICBC NSNCRICBG NSNCRICBO	Original: ERG, 2019 (Section 5, p.11) Revised: U.S. EPA, 2023 (Table 1, p.4)
	SO_2	Dry Scrubber	SDSICIBG SDSICIBO	Original: ERG, 2019 (Section 5, p.11) Revised: U.S. EPA, 2023 (Table 1, p.4)
		Wet Scrubber	SWSICIBG SWSICIBO	Original: ERG, 2019 (Section 5, p.11) Revised: U.S. EPA, 2023 (Table 1, p.4)
Type 21	SO_2	Dry Scrubber	SDSICIBBC SDSICIBSBC	Original: GDIT, 2021 (Figures 3 and 4, p.13 and Figures 7 and 8, p.15) Revised: U.S. EPA, 2023 (Table 5, p.11)
		Wet Scrubber	SWSICIBBC SWSICIBSBC	Original: GDIT, 2021 (Figures 1 and 2, p.12 and Figures 5 and 6, p.14) Revised: U.S. EPA, 2023 (Table 5, p.11)

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