**Table 3-22 State Power Regulations in EPA Platform v6**

| **State/Region** | **Bill** | **Emission Type** | **Emission Specifications** | **Implementation Status** | **Notes** |
| --- | --- | --- | --- | --- | --- |
| Alabama | Alabama Administrative Code Chapter 335-3-8 | NOx | 0.02 lbs/MMBtu for combined cycle EGUs which commenced operation after April 1, 2003; For combined-cycle electric generating units fired by natural gas: 4.0 ppmvd at 15% O2 (0.0178 lbs/MMBtu), by fuel oil- 15.0 ppmvd at 15% O2 (0.0667 lbs/MMBtu) | 2003 |  |
| Arizona | Title 18, Chapter 2, Article 7 | Hg | 90% removal of Hg content of fuel or 0.0087 lbs/GWh annual reduction for all non-cogen coal units > 25 MW | 2017 |  |
| California | CA Reclaim Market | NOx | 9.68 MTons annual cap for list of entities in Appendix A of "Annual RECLAIM Audit Market Report for the Compliance Year 2005" (304 entities) | 1994 | Since the Reclaim Trading Credits are applicable to entities besides power plants, we approximate by hardwiring the NOx and SO2 allowance prices for the calendar year 2006. |
| SO2 | 2.839 MTons in 2016, 2.474 in 2018, and 2.219 in 2020 onward annual cap for list of entities in Appendix A of "Annual RECLAIM Audit Market Report for the Compliance Year 2005" (304 entities) |
| CA AB 32 | CO2 | Power sector and Non-power Sector Cap in Million metric tons. | 2012 | Refer to Section 3.9.4 for details |
| Colorado | 40 C.F.R. Part 60 | Hg | 2012 & 2013: 80% reduction of Hg content of fuel or 0.0174 lbs/GWh annual reduction for Pawnee Station 1 and Rawhide Station 101. 2014 through 2016: 80% reduction of Hg content of fuel or 0.0174 lbs/GWh annual reduction for all coal units > 25 MW 2017 onwards: 90% reduction of Hg content of fuel or 0.0087 lb/GWh annual reduction for all coal units > 25 MW | 2012 |  |
| Clean Air, Clean Jobs Act | NOx, SO2,Hg | Retire Arapahoe 3 by 2014; Cherokee 1 & 2 by 2012, Cherokee 3 by 2017; Cameo 1 & 2; Valmont 5 by 2018; W N Clark 55 & 59 by 2015  Convert following units to natural gas: Arapahoe 4 by 2015; Cherokee 4 by 2018  Install SCRs in Hayden 1 & 2 by 2016; SCR + FGD in Pawnee 1 [already installed] | 2010 |  |
|  | Hg | Comanche Units 1, 2, and 3 together limit of 0.000013 lbs/MWh | 2012 |  |
|  | NOx | Craig Station Unit 1 and Unit 3 NOx Limit 0.28lbs/MMBtu | 2012 |  |
|  | NOx | Craig Station Unit 2 NOx Limit 0.08 lbs/MMBtu | 2012 |  |
| Connecticut | Executive Order 19 and Regulations of Connecticut State Agencies (RCSA) 22a-174-22 | NOx | 0.15 lbs/MMBtu annual rate limit for all fossil units > 15 MW (Non-ozone season only) | 2003 |  |
| Executive Order 19, RCSA 22a-198 & Connecticut General Statues (CGS) 22a-198 | SO2 | Combust fuel with a sulfur content < 3000 ppm; or  Meet an average emission rate of < 0.33 lb SO2/MMBtu for each calendar quarter; or  Meet an average emission rate of < 0.3 lb SO2/MMBtu for each calendar quarter if averaging the emissions from two or more units at a premises |
| CGS section 22a-199 | Hg | 90% removal of Hg content of fuel or 0.6 lbs/TBtu annual reduction for all coal-fired units | 2008 |  |
| Delaware | Regulation 1148: Control of Stationary Combustion Turbine EGU Emissions | NOx | 0.19 lbs/MMBtu ozone season PPMDV for stationary, liquid fuel fired CT EGUs >1 MW 0.39 lbs/MMBtu ozone season PPMDV for stationary, gas fuel fired CT EGUs >1 MW | 2009 |  |
| Regulation No. 1146: Electric Generating Unit (EGU) Multi-Pollutant Regulation | NOx | 0.125 lbs/MMBtu rate limit of NOx annually for all coal and residual-oil fired units > 25 MW | 2009 | The following units have specific NOx, SO2, and Hg annual caps in MTons: Edge Moor 3: 0.773 NOx, 1.391 SO2, & 2012: 0.0000083 Hg, 2013 onwards: 0.0000033 Hg  Edge Moor 4: 1.339 NOx, 2.41 SO2, & 2012: 0.0000144 Hg, 2013 onwards: 0.0000057 Hg Edge More 5: 1.348 NOx & 2.427 SO2 Indian River 3: 0.977 NOx, 1.759 SO2, & 2012: 0.0000105 Hg, 2013 onwards: 0.0000042 Hg Indian River 4: 2.032 NOx, 3.657 SO2, & 2012: 0.0000219 Hg, 2013 onwards: 0.0000087 Hg McKee Run 3 0.244 NOx & 0.439 SO2 |
| SO2 | 0.26 lbs/MMBtu annual rate limit for coal and residual-oil fired units > 25 MW |
| Hg | 2012: 80% removal of Hg content of fuel or 0.0174 lbs/GWh annual reduction for all coal units > 25 MW 2013 onwards: 90% removal of Hg content of fuel or 0.0087 lbs/GWh annual reduction for all coal units > 25 MW | 2012 |
| Regulation 1108: Distillate Fuel Oil rule | SO2 | Any relevant units are to use 0.3% sulfur distillate fuel oil |  | Fuel rule modeled through unit emission rates |
| Georgia | Multi-pollutant Control for Electric Utility Steam Generating Units | SCR, FGD, and Sorbent Injection Baghouse controls to be installed | The following plants must install controls: Bowen, Branch, Hammond, McDonough, Scherer, Wansley, and Yates | Implementation from 2008 through 2015, depending on plant and control type |  |
| Illinois | Title 35, Section 217.706 | NOx | 0.25 lbs/MMBtu summer season rate limit for all fossil units > 25 MW | 2003 |  |
| Title 35, Part 225, Subpart B 225.230 | Hg | 90% removal of Hg content of fuel; or a standard of 0.0080 lb Hg/GWh for sources at or above 25 MW; If facility commenced operation on or before December 31, 2008, start date for implementation must be July 1, 2009 | 2009 | Not Ameren Specific |
| Title 35 Part 225 Subpart B 225.233 | NOx | 0.11 lbs/MMBtu annual rate limit or a rate equivalent to 52% of base annual NOx emissions (whichever is more stringent) and 0.11 lbs/MMBtu ozone season rate limit or a rate equivalent to 80% of base ozone season NOx emissions (whichever is more stringent) for all coal steam units > 25 MW | 2012 | Not Ameren Specific |
| SO2 | 2015 onwards: 0.25 lbs/MMBtu annual rate limit for all coal steam units > 25 MW or a rate equivalent to 35% of the base SO2 emissions (whichever is more stringent) | 2015 |
| Hg | 90% removal of Hg content of fuel or 0.008 lbs/GWh annual reduction for all coal units > 25 MW | 2015 |
| Title 35 Part 225 Subpart B 225.233 (MPS Ameren specific) | NOx | 0.11 lbs/MMBtu annual rate limit and ozone season rate limit Ameren coal steam units > 25 MW | 2012 |  |
| SO2 | 2015 & 2016 onwards: 0.35 lbs/MMBtu annual rate limit for all Ameren coal steam units > 25 MW  2020 onwards: 0.23 lbs/MMBtu annual rate limit for all Ameren coal steam units > 25 MW  System-wide mass emissions limit of 327,996 tons for 10/1/2013-12/31/2020 | 2015  (as modified by board orders 11/2013) |  |
| Title 35 Part 225; Subpart F: Combined Pollutant Standards (REPEALED) | NOx | 0.11 lbs/MMBtu ozone season and annual rate limit for all specified Midwest Gen coal steam units | 2012 | REPEALED |
| SO2 | 0.44 lbs/MMBtu annual rate limit in 2013, decreasing annually to 0.11 lbs/MMBtu in 2019 for all specified Midwest Gen coal steam units | 2013 |
| Hg | 90% removal of Hg content of fuel or 0.08 lbs/GWh annual reduction for all specified Midwest Gen coal steam units | 2015 |
| Title 35 Part 225 Subpart B 225.291-299 (Combined pollutant standard) | NOx | 0.11 lbs/MMBtu group average annual and ozone season emission rates | 2012 | Applies to Midwest Generation’s Coal-Fired Boilers as of 7/1/2006: Crawford (7 & 8), Fisk (19), Joliet ( 6, 7 & 8), Powerton (5 & 6), Waukegan (6, 7 & 8) and Will County (1, 2, 3 & 4) |
| SO2 | Group average annual emission rates of 0.44 lbs/MMBtu in 2013, 0.41 lbs/MMBtu in 2014, 0.38 lbs/MMBtu in 2015 and 2016, 0.15 lbs/MMBtu in 2017, 0.13 lbs/MMBtu in 2018 and 0.11 lbs/MMBtu in 2019 and after, and  annual system-wide mass SO2 emissions limits of no more than 57,000 tons in 2013, 54,000 tons in 2014, 39,000 tons in 2015, and 37,000 tons in 2016 | 2013 |
| Hg | 90% removal of Hg content of fuel or 0.0080 lbs/GWh, compliance determined on a rolling 12-month basis | 2015 |
| Indiana | A.B. Brown Generating Station Consent Order dated 1/11/2016 | SO2 | (A) When Unit 1 is operating alone:  (i) 2152.2 lbs/hr, 1-hour average or 0.855 lbs/MMBtu 1-hour average; and  (ii) 1831.6 lbs/hr, 24-hour average or 0.727 lbs/MMBtu 24-hour average;  (B) When Units 1 & 2 are both in operation, both units shall not exceed the following combined emission rates:  (i) 2152.2 lbs/hr, 1-hour average or 0.426 lbs/MMBtu 1-hour average; and  (ii) 1831.6 lbs/hr, 24-hour average or 0.363 lbs/MMBtu 24-hour average;  (C) When Unit 2 is operating alone:  (i) 1745.7 lbs/hr, 1-hour average or 0.690 lbs/MMBtu 1-hour average; and  (ii) 1485.59 lbs/hr, 24-hour average or 0.588 lbs/MMBtu 24-hour average; | 2016 | https://www.regulations.gov/document?D=EPA-R05-OAR-2016-0090-0005 |
| Clifty Creek Generating Station Consent Order dated 2/1/2016 | SO2 | Units 1-6, 2624.5 lbs SO2/hr on a 720-hr rolling average | 2016 |
| Kansas | NOx Emission Reduction Rule, K.A.R. 28-19-713a.  (Nearman Unit 1) | NOx | Annual rate limit 0.26 lbs/MMBtu | 2012 |  |
| NOx Emission Reduction Rule, K.A.R. 28-19-713a. (Quindaro Unit 2) | NOx | Annual rate limit 0.20 lbs/MMBtu | 2012 |  |
| Louisiana | Title 33 Part IIl - Chapter 22, Control of Nitrogen Oxides | NOx | For units >/= 80 MMBtu/hr, rate limit in lbs/MMBtu: Coal fired : 0.21  Oil-fired: 0.18  All others (gas or liquid): 0.1  Stationary Sources >/= 10 MMBtu/hr, rate limit in lbs/MMBtu: Oil-fired: 0.3  Gas-fired: 0.2 | 2005 | Applicable for all units in Baton Rouge Nonattainment Area & Region of Influence.  Willow Glenn, located in Iberville, obtained a permit that allows its gas-fired units to maintain a cap. These units are separately modeled. |
| Title 33, Part III - Chapter 15, Emission Standards for Sulfur Dioxide | SO2 | 1.2 lbs/MMBtu ozone season ppmvd for all single point sources that emit or have the potential to emit 5 tons or more of SO2 | 2005 |  |
| Maine | Chapter 145 NOx Control Program | NOx | 0.22 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW built before 1995 with a heat input capacity < 750 MMBtu/hr. 0.15 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW built before 1995 with a heat input capacity > 750 MMBtu/hr. 0.20 lbs/MMBtu annual rate limit for all fossil fuel fired indirect heat exchangers, primary boilers, and resource recovery units with heat input capacity > 250 MMBtu/hr | 2005 |  |
| 38 MRSA Section 603-A Low Sulfur in Fuel Rule | SO2 | All fossil units require the use of 0.5% sulfur residual oil [0.52 lbs/MMBtu] | 2018 | Fuel rule modeled through unit emission rates |
| Statue 585-B Title 38, Chapter 4: Protection and Improvement of Air | Hg | 25 lbs annual cap for any facility including EGUs (0.0000125 MTons) | 2010 |  |
| Maryland | Maryland Healthy Air Act  (COMAR 26.11.27) | NOx | The annual NOx tonnage limitations:  1/2009-12/31/2011 - 20.216 MTons  1/1/2012 onward - 16.324 MTons (16.7 MTons minus the tonnage for R. Paul Smith units 3 and 4 which are retired)  The ozone season NOx tonnage limitations  5/1/2009-9/30/2011 - 8.9 MTons  5/1/2012 onward 7.197 MTons (7.227 MTons minus the tonnage for R. Paul Smith units 3 and 4 which are retired) | 2009 |  |
| SO2 | 48.618 MTons from 1/1/2010-12/31/2012  36.467 MTons from 1/1/2013 onward (37.235 minus the tonnage for R. Paul Smith units 3 and 4 which are retired) |
| Hg | 2010 through 2012: 80% removal of Hg content of fuel for 15 specific existing coal steam units 2013 onwards: 90% removal of Hg content of fuel for 15 specific existing coal steam units |
| COMAR 26.11.38  Control of NOx Emissions from Coal-Fired Electric Generating Units | NOx | Phase 1: requires all of the affected units to minimize NOx emissions every day of the ozone season (5/1-9/30) by optimizing the pollution controls that are already in place.  Phase 2: requires the owner or operator of units that have not installed SCR (H. A. Wagner Unit 2, C. P. Crane Units 1 and 2, Chalk Point Unit 2, and Dickerson Units 1, 2 and 3) to choose from the following:  Option 1—By June 1, 2020, install and operate an SCR control system that can meet a NOx emission rate of 0.09 lbs/MMBtu during the ozone season based on a 30-day rolling average;  Option 2—By June 1, 2020, permanently retire the unit;  Option 3—By June 1, 2020, switch fuel permanently from coal to natural gas and operate the unit on natural gas; or  Option 4—By June 1, 2020, meet a system wide, daily NOx tonnage cap of 21 tons per day for every day of the ozone season or meet a system wide NOx emission rate of 0.13 lbs/MMBtu as a 24-hour block average. The rate and the cap in option 4 are consistent with levels assuming SCR controls on all units. If option 4 is selected, deeper reductions starting in May 2016, 2018 and 2020 must also be achieved.  2016—Meet a 30-day system wide rolling average NOx emission rate of 0.13 lbs/MMBtu during the ozone season.  2018—Meet a 30-day system wide rolling average NOx emission rate of 0.11 lbs/MMBtu during the ozone season.  2020—Meet a 30-day system wide rolling average NOx emission rate of 0.09 lbs/MMBtu during the ozone season.  Without option 4, the allowable 30-day system wide rolling average NOx emission rate is 0.15 lbs/MMBtu during the ozone season.  Option 4 also includes provisions to ensure that the reliability of the electrical system is maintained. | Phase 1: May 1, 2015  Phase 2:2020 | Affected EGUs are all coal-fired EGUs owned by Raven Power Finance LLC (Raven Power) and NRG Energy, Inc. (NRG) in Maryland.  Plants that are part of the Raven system include Brandon Shores Units 1 and 2, H. A. Wagner Units 2 and 3, and C. P. Crane Units 1 and 2.  Plants that are part of the NRG system include: Morgantown Units 1 and 2, Chalk Point Units 1 and 2, and Dickerson Units 1, 2 and 3.  The Crane units were sold on or around 2/16/2016 and are no longer part of the Raven System. |
| Massachusetts | 310 CMR 7.29 | NOx | 1.5 lbs/MWh annual GPS for Brayton Point, Mystic Generating Station, Mount Tom, Canal, and Salem Harbor | 2006 |  |
| SO2 | 3.0 lbs/MWh annual GPS for Brayton Point, Mystic Generating Station, Mount Tom, Canal, and Salem Harbor |
| Hg | 2012: 85% removal of Hg content of fuel or 0.0000025 lbs/MWh annual GPS for Brayton Point, Mystic Generating Station, Mount Tom, Canal, and Salem Harbor  2013 onwards: 95% removal of Hg content of fuel or 0.0000025 lbs/MWh annual GPS for Brayton Point, Mystic Generating Station, Mount Tom, Canal, and Salem Harbor | Brayton units 1 through 3 have an annual Hg cap of 0.0000733 MTons Mt. Tom 1 has an annual Hg cap of 0.00000205 MTons Salem Harbor units 1 through 3 have an annual Hg cap of 0.0000106 MTons |
| 310 CMR 7.04 | SO2 | Sulfur in Fuel Oil Rule requires the use of 0.5% sulfur residual oil [0.52 lbs/MMBtu] by July 1, 2014 for units greater than 250 MMBtu energy input; by July 1, 2018 for all residual oil units except for those located in the Berkshire APCD. | 2014 | Fuel rule modeled through unit emission rates |
| Michigan | Part 18 Rules – R 336.1801 (2) (a) | NOx | For all fossil units > 25 MW, and annual PTE of NOx >25 tons,0.25 lbs/MMBtu ozone season rate, OR 65% NOx reductions from 1990 levels | 2004 |  |
| Part 4 Rules – R 336.1401 | SO2 | SO2 ppmvd rates in 50% excess air for units in Wayne county: Pulverized coal: 550;Other coal: 420;Distillate oil Nos. 1 & 2: 120;Used oil: 300;Crude and Heavy oil: 400 | 2012 | Not modeled in IPM as limits are within SIP rates |
| For all other units,  with 0-500,000 lbs Steam per Hour Plant Capacity: 2.5  SO2 ppmvd rates at 50% excess air for solid fuel is 890 and for liquid fuel is 630; the pounds of SO2 per MMBtu of heat input for solid fuel is 2.5 and 1.67 for liquid fuel with >500,000 lbs Steam per Hour Plant Capacity: 1.67  SO2 ppmvd rates at 50% excess air for solid fuel is 590 and for liquid fuel is 420; the pounds of SO2 per MMBtu of heat input for solid fuel is 1.67 and 1.11 for liquid fuel |
| Part 15. Emission Limitations and Prohibitions - Mercury | Hg | 90% removal of Hg content of fuel annually for all coal units > 25 MW  An affected EGU is defined in Part 15 as unit with a nameplate capacity of greater than 25 MW producing electricity for sale.  An out-put based emission standard of 0.008 lb of Hg per gigawatts hour on a 12-month rolling average as determined at the end of each calendar month | 2015 |  |
| Minnesota | Minnesota Hg Emission Reduction Act | Hg | 90% removal of Hg content of fuel annually for all coal facilities > 500 MW combined; Dry scrubbed units must implement by December 31, 2010; Wet scrubbed units must implement by December 31, 2014. | 2006 |  |
| Missouri | 10 CSR 10-6.350 | NOx | 0.25 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW in the following counties: Bollinger, Butler, Cape Girardeau, Carter, Clark, Crawford, Dent, Dunklin, Gasconade, Iron, Lewis, Lincoln, Madison, Marion, Mississippi, Montgomery, New Madrid, Oregon, Pemiscot, Perry, Phelps, Pike, Ralls, Reynolds, Ripley, St. Charles, St. Francois, Ste. Genevieve, Scott, Shannon, Stoddard, Warren, Washington and Wayne 0.18 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW the following counties: City of St. Louis, Franklin, Jefferson, and St. Louis 0.35 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW in the following counties: Buchanan, Jackson, Jasper, Randolph, and any other county not listed  0.68 lbs NOx/MMBtu for cyclone units burning 100,000 or more passenger tire equivalents (PTE). | 2004 |  |
| Montana | Montana Mercury Rule Adopted 10/16/06 | Hg | 0.90 lbs/TBtu annual rate limit for all non-lignite coal units 1.50 lbs/TBtu annual rate limit for all lignite coal units | 2010 |  |
| New Hampshire | RSA 125-O: 11-18 | Hg | 80% reduction of aggregated Hg content of the coal burned at the facilities for Merrimack Units 1 & 2 and Schiller Units 4, & 6 | 2012 | Unit 5 is no longer subject because PSNH installed a new unit. |
| ENV-A2900 Multiple pollutant annual budget trading and banking program | NOx | 2.40 MTons summer cap for all fossil steam units > 250 MMBtu/hr operated at any time in 1990 and all new units > 15 MW 3.64 MTons annual cap for Merrimack 1 & 2, Newington 1, and Schiller 4 through 6 | 2007 |  |
| SO2 | 7.29 MTons annual cap for Merrimack 1 & 2, Newington 1, and Schiller 4 through 6 |
| Env -A 2300 - Mitigation of Regional Haze | SO2 | 90% SO2 control at Merrimack 1 & 2; 0.5 lb SO2/MMBtu 30 day rolling average at Newington 1 | 2013 |
| NOx | 0.30 lb NOx/MMBtu 30-day rolling average at Merrimack 2; 0.35 lb NOx/MMBtu when burning oil and 0.25 lb NOx/MMBtu when burning oil and gas at Newington 1(permit condition). |
| New Jersey | N.J. A. C. Title 7, Chapter 27, Subchapter 10.2 | SO2 | 0.15 (30 day rolling average) lbs/MMBtu | 2012 |  |
| N.J.A.C. 7:27-27.5, 27.6, 27.7, and 27.8 | Hg | 90% removal of Hg content of fuel annually for all coal-fired units or <= 3.0 mg/MWh (net)  95% removal of Hg content of fuel annually for all MSW incinerator units or <= 28 ug/dscm | 2007 |  |
| N.J. A. C. Title 7, Chapter 27, Subchapter 19, Table 1 | NOx | Annual rate limits in lbs/MMBtu for the following technologies: 1.0 for tangential and wall-fired wet-bottom coal boilers serving an EGU 0.60 for cyclone-fired wet-bottom coal boilers serving an EGU | 2007 | No longer operative. Operative through December 14, 2012 |
| N.J. A. C. Title 7, Chapter 27, Subchapter 19, Table 2 | NOx | Annual rate limits in lbs/MMBtu for the following technologies: 0.38 for tangential dry-bottom coal boilers serving an EGU 0.45 for wall-fired dry-bottom coal boilers serving an EGU 0.55 for cyclone-fired dry-bottom coal boilers serving an EGU  Limits in lbs/MWh  1.50 for tangential, wall-fired, and cyclone-fired coal boilers serving an EGU  2.00 for tangential oil and/or gas boilers serving an EGU  2.80 for wall fired oil and/or gas boilers serving an EGU  4.30 for cyclone-fired oil and/or gas boilers serving an EGU  2.00 for tangential and wall fired gas only boilers serving an EGU  4.30 for cyclone fired gas only boilers serving an EGU | Operative from December 15, 2012 through April 30, 2015 |  |
| N.J. A. C. Title 7, Chapter 27, Subchapter 19, Table 3 | NOx | Annual rate limit lbs/MWh - 1.50 for coal fired boilers serving an EGU; 2.00 for heavier than No.2 fuel oil fired boilers serving an EGU; 1.00 for No.2 and lighter fuel oil fired and gas only fired boilers serving an EGU | 05/01/2015 |  |
| N.J. A. C. Title 7, Chapter 27, Subchapter 19, Table 6; non- High Electricity demand Day (HEDD) unit | NOx | 2.2 lbs/MWh for gas-burning simple cycle combustion turbine units 3.0 lbs/MWh for oil-burning simple cycle combustion turbine units 1.3 lbs/MWh for gas-burning combined cycle CT or regenerative cycle CT units 2.0 lbs/MWh for oil-burning combined cycle CT or regenerative cycle CT units | 05/20/2009 |  |
| N.J. A. C. Title 7, Chapter 27, Subchapter 19, Table 7; High Electricity demand Day (HEDD) unit | NOx | 1.0 lbs/MWh for gas-burning simple cycle combustion turbine units 1.6 lbs/MWh for oil-burning simple cycle combustion turbine units 0.75 lbs/MWh for gas-burning combined cycle CT or regenerative cycle CT units 1.2 lbs/MWh for oil-burning combined cycle CT or regenerative cycle CT units | 2007 | On and after May 1, 2015, the owner or operator of a stationary combustion turbine that is a HEDD unit or a stationary combustion turbine that is capable of generating 15 MW or more and that commenced operation on or after May 1, 2005 shall comply with limits outlines “in Table 7 during operation on high electricity demand days, regardless of the fuel combusted, unless combusting gaseous fuel is not possible due to gas curtailment." |
| New York | Part 237 | NOx | 39.91 MTons [Thousand tons] non-ozone season cap for fossil fuel units > 25 MW | 2004 | Repealed |
| Part 238 | SO2 | 131.36 MTons [Thousand tons] annual cap for fossil fuel units > 25 MW | 2005 | Repealed |
| Mercury Reduction Program for Coal-Fired Electric Utility Steam Generating Units | Hg | 786 lbs annual cap through 2014 for all coal fired boiler or CT units >25 MW after Nov. 15, 1990. For facilities identified in Table 1 of Part 246 and includes 40 lbs set aside.  0.60 lbs/TBtu annual rate limit for all coal units > 25 MW developed after Nov.15 1990 for new units and existing facilities – effective Jan 1, 2015. | 2010 | https://govt.westlaw.com/nycrr/Browse/Home/NewYork/NewYorkCodesRulesandRegulations?guid=Ic3039690b5a011dda0a4e17826ebc834&originationContext=documenttoc&transitionType=Default&contextData=%28sc.Default%29 |
| Subpart 227-2 Reasonably Available Control Technology (RACT) For Major Facilities of Oxides Of Nitrogen (NOx) | NOx | Annual rate in lbs/MMBtu for very large boilers >250 MMBtu/hr on or after July 1, 2014; Gas only, tangential & wall fired : 0.08 Gas/oil tangential & wall fired : 0.15; cyclone: 0.2 Coal Wet Bottom, tangential & wall fired : 0.12; cyclone: 0.2 Coal Dry Bottom, tangential & wall fired : 0.12; stokers: 0.08 | 2004 |  |
| Annual rate in lbs/MMBtu for large boilers between 100 and 250 MMBtu/hr on or after July 1, 2014; Gas Only: 0.06 Gas/Oil: 0.15 Pulverized Coal: 0.20 Coal (Overfeed Stoker/FBC): 0.8 |  |
| Annual rate in lbs/MMBtu for mid-size boilers between 25 and 100 MMBtu/hr on or after July 1, 2014; Gas Only: 0.05 Distillate Oil/Gas: 0.08 Residual Oil/Gas: 0.20 |  |
| Combined cycle and cogeneration CTs must have an approved case by case RACT determination from the Department by July 1, 2014.  Simple cycle CTs are required to meet 50 ppm on natural gas and 100 ppm on distillate oil.\* | Compliance with these emission limits must be determined with a one hour average during the ozone season and a 30-day average during the non-ozone season unless the owner or operator chooses to use a CEMS under the provisions of section 227- 2.6(b) of this Subpart. |
| **Stationary internal combustion engines** having a maximum mechanical output => 200 brake horsepower in a severe ozone nonattainment area or having a maximum mechanical output rating =>400 brake horsepower outside a severe ozone nonattainment  area must comply with one of the emission limits in paragraph (1), (2), or (3) of this subdivision or a case-by-case RACT determination made pursuant to paragraph (4) of this subdivision, as applicable: (1) For internal combustion engines fired solely with natural gas: 1.5 grams per brake horsepower-hour. (2) For internal combustion engines fired with landfill gas or digester gas (solely or in combination with natural gas): 2.0 grams per brake horsepower-hour. (3) For internal combustion engine fired with distillate oil (solely or in combination with other fuels): 2.3 grams per brake horsepower-hour.  (4) For stationary internal combustion engines fired primarily with fuels not listed above, the owner or operator must submit a proposal for RACT to be implemented that includes descriptions of:  (i) the available NOx control technologies, the projected effectiveness of the technologies considered, and the costs for installation and operation for each of the technologies; and(ii) the technology and the appropriate emission limit selected as RACT considering the costs for installation and operation of the technology.  (5) Any stationary internal combustion engine may rely on an emission limit that reflects a 90 percent or greater NOx reduction from the engine's actual 1990 baseline emissions, if such emissions baseline exists.  (6) Emergency power generating stationary internal combustion engines, and engine test cells at engine manufacturing facilities that are used for either research and development purposes, reliability testing, or quality assurance performance testing are exempt from the requirements of this subdivision. |  |
| Part 242 CO2 Budget Trading Program | CO2 | Any unit that, at any time on or after January 1, 2005, serves an electricity generator with a nameplate capacity equal to or greater than 25 MWe shall be a CO2 budget unit, and any source that includes one or more such units shall be a CO2 budget source, subject to the requirements of this Part.  (a) The CO2 Budget Trading Program base budget is 35,228,822 tons, for the 2014 allocation year.  (b) The CO2 Budget Trading Program base budget is 34,348,101 tons, for the 2015 allocation year.  (c) The CO2 Budget Trading Program base budget is 33,489,399 tons, for the 2016 allocation year.  (d) The CO2 Budget Trading Program base budget is 32,837,536 tons for the 2017 allocation year.  (e) The CO2 Budget Trading Program base budget is 32,016,597 tons for the 2018 allocation year.  (f) The CO2 Budget Trading Program base budget is 31,216,182 tons, for the 2019 allocation year.  (g) The CO2 Budget Trading Program base budget is 30,435,778 tons, annually for the 2020 allocation year and each succeeding allocation year. | 2015 | Full Rule Link:  https://govt.westlaw.com/nycrr/Browse/Home/NewYork/NewYorkCodesRulesandRegulations?guid=Iafc5f680d5e011ddb477e8e3dda68a63&originationContext=documenttoc&transitionType=Default&contextData=%28sc.Default%29&bhcp=1  Part 242-2 CO2 Allowance Allocations Link:  https://govt.westlaw.com/nycrr/Browse/Home/NewYork/NewYorkCodesRulesandRegulations?guid=Idb97d060dbeb11dd9768bd0e013d693a&originationContext=documenttoc&transitionType=Default&contextData=%28sc.Default%29 |
| Part 251 [CO2 Performance Standards for Major Electric Generating Facilities](http://www.dec.ny.gov/regs/83094.html) | CO2 | 1450 lbs/MWh rate limit for New Combustion Turbines =>25MW  925 lbs/MWh rate limit for New Fossil Fuel except CT =>25MW | 2012 |  |
| North Carolina | NC Clean Smokestacks Act: Statute 143-215.107D | NOx | 25 MTons annual cap for Progress Energy coal plants > 25 MW and 31 MTons annual cap for Duke Energy coal plants > 25 MW | 2007 |  |
| SO2 | 2012: 100 MTons annual cap for Progress Energy coal plants > 25 MW and 150 MTons annual cap for Duke Energy coal plants > 25 MW 2013 onwards: 50 MTons annual cap for Progress Energy coal plants > 25 MW and 80 MTons annual cap for Duke Energy coal plants > 25 MW | 2009 |  |
| SECTION .2500 – Mercury Rules for Electric Generators | Hg | Coal-fired electric steam >25 MW to comply with the mercury emission caps of 1.133 tons (36,256 ounces) per year between 2010 and 2017 inclusive and 0.447 tons (14,304 ounces) per year for 2018 and thereafter | 2010 | Vacated |
| 15A NCAC 02D .2511 | Hg | Duke Energy and Progress Energy Hg control plans submitted on January 1, 2013 and are awaiting approval. All control technologies and limitations must be implemented by December 31, 2017. | 2017 |  |
| Oregon | Oregon Administrative Rules, Chapter 345, Division 24 | CO2 | 675 lbs/MWh annual rate limit for new combustion turbines burning natural gas with a CF >75% and all new non-base load plants (with a CE <= 75%) emitting CO2 | 1997 |  |
| Oregon Utility Mercury Rule - Existing Units | Hg | 90% removal of Hg content of fuel reduction or 0.6 lbs/TBtu limitation for all existing coal units >25 MW | 2012 |  |
| Oregon Utility Mercury Rule - Potential Units | Hg | 25 lbs limit for all potential coal units > 25 MW | 2009 |  |
| Texas | Senate Bill 7 Chapter 101 | SO2 | 273.95 MTons cap of SO2 allowances allocated annually for all grandfathered units built before 1971 and electing units in East Texas Region | 2003 |  |
| NOx | Annual cap for all grandfathered units built before 1971 in MTons: 84.50in East Texas, 18.10 in West Texas, 1.06 in El Paso Region |
| Chapter 117 | NOx | East and Central Texas annual rate limits in lbs/MMBtu for units that came online before 1996:  Gas fired units: 0.14 lb/MMBtu heat input Coal fired units: 0.165 lb/MMBtu heat input Stationary gas turbines: 0.14 lb/MMBtu heat input  System cap: tons per year according to §117.3020(c) | 2007 | Units are also allowed to comply by reducing the same amount of NOx on a monthly basis using a system cap or by purchasing credits.   East and Central Texas, Dallas/Fort Worth Area, Beaumont-Port Arthur region units are assumed to be in compliance based on their reported 2011 ETS rates. The regulations for these regions are not modeled. |
| Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area limits for utility boilers, auxiliary steam boilers, and stationary gas turbines used in an electric power generating system:  Utility boilers:  • Large utility systems:   0.033 lb/MMBtu heat input rolling 24-hour (March - October) and rolling 30-day (November, December, January, February);   0.033 lb/MMBtu heat input, system-wide heat input weighted average rolling 168-hour  • Small utility systems: 0.06 lb/MMBtu heat input rolling 24-hour (March - October) and rolling 30-day (November, December, January, February)  • 0.50 lb/MWh annual output  Auxiliary steam boilers:  • Natural gas or combination of natural gas and waste oil: 0.26 lb/MMBtu heat input rolling 24-hour and 0.20 lb/MMBtu heat input rolling 30-day  • Fuel oil: 0.30 lb/MMBtu heat input rolling 24-hour  • Mixture of natural gas and fuel oil: heat input weighted average of applicable (above) specifications rolling 24-hour according to §117.1310(a)(2)(C)  • Or applicable NSPS NOx emission limit in Subparts D, Db, or Dc  Stationary gas turbines:  • Non-peaking units ≥ 30 MW (annual MWh ≥ 2500 hours X unit MW rating):   Natural gas: 42 ppmv (15% O2, dry) block one-hour   Fuel oil: 65 ppmv (15% O2, dry) block one-hour  • Peaking units (annual MWh < 2500 hours X unit MW rating):   Natural gas: 0.20 lb/MMBtu heat input block one-hour   Fuel oil: 0.30 lb/MMBtu heat input block one-hour |
| Houston-Galveston-Brazoria Eight-Hour Ozone Nonattainment Area annual Mass Emissions Cap and Trade (MECT) Program for EGUs and non-EGUs. EGUs include utility boilers, auxiliary steam boilers, stationary gas turbines, and duct burners used in turbine exhaust ducts used in an electric power generating system:  39.99 MTons NOx allowances allocated annually to all MECT sources (EGUs and Non-EGUs combined); 17.57 MTons NOx allowances allocated annually to all MECT sources (EGUs) |
| Beaumont-Port Arthur Area limits for utility boilers, auxiliary steam boilers, and stationary gas turbines used in an electric power generating system:  Utility boilers:  • 0.10 lbs/MMBtu heat input daily average  • System cap in lb/day based on rolling 30-day cap and maximum daily cap according to §117.1020(c)(1)-(2)  Auxiliary steam boilers:  • Natural gas or combination of natural gas and waste oil: 0.26 lb/MMBtu heat input rolling 24-hour and 0.20 lb/MMBtu heat input rolling 30-day  • Fuel oil: 0.30 lb/MMBtu heat input rolling 24-hour  • Mixture of natural gas and fuel oil: heat input weighted average of applicable (above) specifications rolling 24-hour according to §117.1005(d)  • Or applicable NSPS NOx emission limit in Subparts D, Db, or Dc  Stationary gas turbines:  • Non-peaking units ≥ 30 MW (annual MWh ≥ 2500 hours X unit MW rating):   Natural gas: 42 ppmv (15% O2, dry) block one-hour   Fuel oil: 65 ppmv (15% O2, dry) block one-hour  • Peaking units (annual MWh < 2500 hours X unit MW rating):   Natural gas: 0.20 lb/MMBtu heat input block one-hour   Fuel oil: 0.30 lb/MMBtu heat input block one-hour |
| Utah | R307-424 Permits: Mercury Requirements for Electric Generating Units | Hg | 90% removal of Hg content of fuel annually or 0.65 lbs/MMBtu for all coal units > 25 MW | 2013 |  |
| Washington | Washington State House Bill 3141 | CO2 | $1.45/MTons cost (2004$) for all new fossil-fuel power plant | 2004 |  |
| Washington State House Bill 5769 | CO2 | 970 lbs/MWh rate limit for new coal plants | 2011 |  |
| Wisconsin | NR 428 Wisconsin Administration Code | NOx | Annual rate limits in lbs/MMBtu for coal fired boilers > 1,000 MMBtu/hr : Wall fired, tangential fired, cyclone fired, and fluidized bed: 2013 onwards: 0.10 Arch fired: 2009 onwards: 0.18 | 2009 |  |
| Annual rate limits in lbs/MMBtu for coal fired boilers between 500 and 1,000 MMBtu/hr:  Wall-fired with a heat release rate=> 17,000 Btu per cubic feet per hour; 2013 onwards: 0.17 ; if heat input is lesser:  Tangential fired: 2009 onwards: 0.15 Cyclone fired: 2013 onwards: 0.15 Fluidized bed: 2013 onwards: 0.10  Arch fired: 2009 onwards: 0.18 |
| Annual rate limits in lbs/MMBtu for coal fired boilers between 250 and 500 MMBtu/hr:  Same as for coal boiled between 500 and 1000 MMBtu/hr in addition to: Stoker Fired: 0.20 |
| Annual rate limits in lbs/MMBtu for coal fired boilers between 50 and 250 MMBtu/hr:  Same as for coal boiled between 500 and 1000 MMBtu/hr in addition to: Stoker Fired: 0.25 |
| Annual rate limits for CTs in lbs/MMBtu:  Natural gas CTs > 50 MW: 0.11 Distillate oil CTs > 50 MW: 0.28 Biologically derived fuel CTs > 50 MW: 0.15 Natural gas CTs between 25 and 49 MW: 0.19 Distillate oil CTs between 25 and 49 MW: 0.41 Biologically derived fuel CTs between 25 and 49 MW: 0.15 |  |
| Annual rate limits for CCs in lbs/MMBtu:  Natural gas CCs > 25 MW: 0.04 Distillate oil CCs > 25 MW: 0.18 Biologically derived fuel CCs > 25 MWs: 0.15 Natural gas CCs between 10 and 24 MW: 0.19 |  |
| Chapter NR 44.12/446.13 Control of Mercury Emissions | Hg | Large (150MW capacity or greater) or small (between 25 and 150 MW) coal-fired EGU, 2015 onwards: 90% removal of Hg content of fuel or 0.0080 lbs/GWh reduction in coal fired EGUs > 150 MW | 2015 |  |
| Chapter NR 446.14 Multi-pollutant reduction alternative for coal-fired electrical generating units | Hg | All Coal>25MW;  70% reduction in fuel, or 0.0190 lbs per GW-hr from CY 2015 – CY 2017 (0.00005568 lbs/MMBtu) 80% reduction in fuel, or 0.0130 lbs per GW-hr from CY2018 – CY 2020 (0.0000381 lbs/MMBtu) 90% reduction in fuel, or 0.0080 lbs per GW-hr from January 1, 2021 onwards (0.00000234 lbs/MMBtu) | 2015 | Alternative already modeled in IPM |
| SO2 | All Coal>25MW; 0.10 lbs per MMBtu by January 1, 2015 |
| NOx | All Coal>25MW; 0.07 lbs per MMBtu by January 1, 2015 |