Table 3-23 State Power Regulations included in EPA Platform v6

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
Alabama	Alabama Administrative Code Chapter 335-3-8	NO_x	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	NO_x	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 NO_x and SO_2 allowance prices for the calendar year 2006.
		SO_2	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	CO_2	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	NO_x, SO_2, 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	
		NO_x	Craig Station Unit 1 and Unit 3 NO_x Limit 0.28lbs/MMBtu	2012	
		NO_x	Craig Station Unit 2 NO_x Limit 0.08 lbs/MMBtu	2012	
Connecticut	Executive Order 19 and Regulations of Connecticut State Agencies (RCSA) 22a-174-22	NO_x	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	SO_2	Combust fuel with a sulfur content < 3000 ppm; or Meet an average emission rate of < 0.33 lb SO_2/MMBtu for each calendar quarter; or Meet an average emission rate of < 0.3 lb SO_2/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	

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
Delaware	Regulation 1148: Control of Stationary Combustion Turbine EGU Emissions	NO_x	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	NO_x	0.125 lbs/MMBtu rate limit of NO_x annually for all coal and residual-oil fired units > 25 MW	2009	The following units have specific NO_x, SO_2, and Hg annual caps in MTons: Edge Moor 3: 0.773 NO_x, 1.391 SO_2, & 2012: 0.0000083 Hg, 2013 onwards: 0.0000033 Hg Edge Moor 4: 1.339 NO_x, 2.41 SO_2, & 2012: 0.0000144 Hg, 2013 onwards: 0.0000057 Hg Edge More 5: 1.348 NO_x & 2.427 SO_2 Indian River 3: 0.977 NO_x, 1.759 SO_2, & 2012: 0.0000105 Hg, 2013 onwards: 0.0000042 Hg Indian River 4: 2.032 NO_x, 3.657 SO_2, & 2012: 0.0000219 Hg, 2013 onwards: 0.0000087 Hg McKee Run 3 0.244 NO_x & 0.439 SO_2
		SO_2	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	SO_2	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	NO_x	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	NO_x	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
		SO_2	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 SO_2 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	
		SO_2	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)	

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
	Title 35 Part 225; Subpart F: Combined Pollutant Standards (REPEALED)	NO_x	0.11 lbs/MMBtu ozone season and annual rate limit for all specified Midwest Gen coal steam units	2012	REPEALED
		SO_2	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)
		SO_2	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	SO_2	(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	SO_2	Units 1-6, 2624.5 lbs SO2/hr on a 720-hr rolling average	2016	
Kansas	NO_x Emission Reduction Rule, K.A.R. 28-19-713a. (Nearman Unit 1)	NO_x	Annual rate limit 0.26 lbs/MMBtu	2012	
	NO_x Emission Reduction Rule, K.A.R. 28-19-713a. (Quindaro Unit 2)	NO_x	Annual rate limit 0.20 lbs/MMBtu	2012	
Louisiana	Title 33 Part III - Chapter 22, Control of Nitrogen Oxides	NO_x	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	SO_2	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 SO_2	2005	

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
Maine	Chapter 145 NO_x Control Program	NO_x	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	SO_2	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)	NO_x	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	
		SO_2	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		

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
	COMAR 26.11.38 Control of NOx Emissions from Coal-Fired Electric Generating Units	NO_x	Phase 1: requires all of the affected units to minimize NO_x 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 NO_x 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 NO_x tonnage cap of 21 tons per day for every day of the ozone season or meet a system wide NO_x 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 NO_x emission rate of 0.13 lbs/MMBtu during the ozone season. 2018—Meet a 30-day system wide rolling average NO_x emission rate of 0.11 lbs/MMBtu during the ozone season. 2020—Meet a 30-day system wide rolling average NO_x emission rate of 0.09 lbs/MMBtu during the ozone season. Without option 4, the allowable 30-day system wide rolling average NO_x 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	NO_x	1.5 lbs/MWh annual GPS for Brayton Point, Mystic Generating Station, Mount Tom, Canal, and Salem Harbor	2006	
		SO_2	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	SO_2	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

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
Michigan	Part 18 Rules – R 336.1801 (2) (a)	NO_x	For all fossil units > 25 MW, and annual PTE of NO_x >25 tons,0.25 lbs/MMBtu ozone season rate, OR 65% NO_x reductions from 1990 levels	2004	
	Part 4 Rules – R 336.1401	SO_2	SO_2 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 SO_2 ppmvd rates at 50% excess air for solid fuel is 890 and for liquid fuel is 630; the pounds of SO_2 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 SO_2 ppmvd rates at 50% excess air for solid fuel is 590 and for liquid fuel is 420; the pounds of SO_2 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	NO_x	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	NO_x	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	
		SO_2	7.29 MTons annual cap for Merrimack 1 & 2, Newington 1, and Schiller 4 through 6		
	Env -A 2300 - Mitigation of Regional Haze	SO_2	90% SO_2 control at Merrimack 1 & 2; 0.5 lb SO_2/MMBtu 30 day rolling average at Newington 1	2013	
		NO_x	0.30 lb NO_x/MMBtu 30-day rolling average at Merrimack 2; 0.35 lb NO_x/MMBtu when burning oil and 0.25 lb NO_x/MMBtu when burning oil and gas at Newington 1(permit condition).		

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
New Jersey	N.J. A. C. Title 7, Chapter 27, Subchapter 10.2	SO_2	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	NO_x	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	NO_x	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	NO_x	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	NO_x	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	NO_x	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	NO_x	39.91 MTons [Thousand tons] non-ozone season cap for fossil fuel units > 25 MW	2004	Repealed
	Part 238	SO_2	131.36 MTons [Thousand tons] annual cap for fossil fuel units > 25 MW	2005	Repealed

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
	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 (NO_x)	NO_x	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.

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
			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 NO_x 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 NO_x 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.		

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
	Part 242 CO_2 Budget Trading Program	CO_2	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 CO_2 budget unit, and any source that includes one or more such units shall be a CO_2 budget source, subject to the requirements of this Part. (a) The CO_2 Budget Trading Program base budget is 35,228,822 tons, for the 2014 allocation year. (b) The CO_2 Budget Trading Program base budget is 34,348,101 tons, for the 2015 allocation year. (c) The CO_2 Budget Trading Program base budget is 33,489,399 tons, for the 2016 allocation year. (d) The CO_2 Budget Trading Program base budget is 32,837,536 tons for the 2017 allocation year. (e) The CO_2 Budget Trading Program base budget is 32,016,597 tons for the 2018 allocation year. (f) The CO_2 Budget Trading Program base budget is 31,216,182 tons, for the 2019 allocation year. (g) The CO_2 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 CO_2 Performance Standards for Major Electric Generating Facilities	CO_2	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	NO_x	25 MTons annual cap for Progress Energy coal plants > 25 MW and 31 MTons annual cap for Duke Energy coal plants > 25 MW	2007	
		SO_2	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	CO_2	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 CO_2	1997	

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
	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	SO_2	273.95 MTons cap of SO_2 allowances allocated annually for all grandfathered units built before 1971 and electing units in East Texas Region	2003	
		NO_x	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	NO_x	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 NO_x 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		

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
			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% O_2, dry) block one-hour □ Fuel oil: 65 ppmv (15% O_2, 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	CO_2	$1.45/MTons cost (2004$) for all new fossil-fuel power plant	2004	
	Washington State House Bill 5769	CO_2	970 lbs/MWh rate limit for new coal plants	2011	
Wisconsin	NR 428 Wisconsin Administration Code	NO_x	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		

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
			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
		SO_2	All Coal>25MW; 0.10 lbs per MMBtu by January 1, 2015		
		NO_x	All Coal>25MW; 0.07 lbs per MMBtu by January 1, 2015		