Table 3-29 State Power Regulations included in EPA 2023 Reference Case

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
Alabama	Alabama Administrative Code Chapter 335-3-8	NO_x	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% O_2 (0.0178 lbs/MMBtu), by fuel oil: 15.0 ppmvd at 15% O_2: (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	
	A.A.C. Section R18-2-734	Hg	90% removal of Hg content of fuel or 0.0087 lbs/GWh annual reduction for all non-cogen coal units > 25 MW	2015	https://regulations.justia.com/states/arizona/title-18/chapter-2/article-7/r18-2-734/
	A.A.C. Section R18-2-703	SO_2	When solid fuel or low sulfur oil is used 1.0 heat input per 3-hour average for installations which commenced construction/major modification prior to May 30, 1972 0.8 lbs/MMBtu heat input per 3-hour average for installations which commenced construction/major modification after May 30, 1972 When high sulfur oil is used 2.2 lbs/MMBtu heat input per 3-hour average	1993 (amended 2009)	https://regulations.justia.com/states/arizona/title-18/chapter-2/article-7/r18-2-703/
		NO_x	For steam power generating installations which commenced construction or major alteration after May 30, 1972, on a maximum 3-hour average calculated as nitrogen dioxide: 0.20 lbs/MMBtu heat input when gaseous fossil fuel is fired 0.30 lbs/MMBtu heat input when liquid fossil fuel is fired 0.70 lbs/MMBtu heat input when solid fossil fuel is fired		
	A.A.C. Section R18-2-903	SO_2	0.8 lbs/MMBtu heat input for liquid fossil fuel or liquid fossil fuel and wood residue	1993 (amended 2008)	https://regulations.justia.com/states/arizona/title-18/chapter-2/article-9/r18-2-903/
Arizona – Pinal County	Code 22 5-22-960	SO_2	Fossil Fuel Fired Steam Generators on a maximum of 2-hour average calculated as sulfur dioxide: 0.80 lbs/MMBtu heat input when oil is fired for a new source 1.0 lbs/MMBtu heat input when oil is fired for an existing source	Units commenced construction after March 1975	https://www.pinal.gov/DocumentCenter/View/9686/PCAQCD--Code-of-Regulations-Updated-January-25-2023-PDF
	Code 22 5-22-970	NO_2	For Fossil Fuel Fired Steam Generator, on a maximum of 2-hour averages calculated as nitrogen dioxide: 0.20 lbs/MMBtu heat input when gaseous fossil fuel is fired 0.30 lbs/MMBtu heat input when liquid fossil fuel is fired 0.70 lbs/MMBtu heat input when solid fossil fuel is fired	Units commenced construction after March 1975	https://www.pinal.gov/DocumentCenter/View/9686/PCAQCD--Code-of-Regulations-Updated-January-25-2023-PDF
	Code 23-5-1010	SO_2	Combustion turbines: 1.0 lbs/MMBtu heat input	1993	https://www.pinal.gov/DocumentCenter/View/9686/PCAQCD--Code-of-Regulations-Updated-January-25-2023-PDF
Arizona – Pima County	PCC 17.16.500	SO_2	0.8 lbs/MMBtu heat input for liquid fossil fuel or liquid fossil fuel and wood residue (for those who obtained an installation permit prior to May 14, 1979 for two or more fuel burning equipment or steam generating installations)	1993	https://codelibrary.amlegal.com/codes/pimacounty/latest/pimacounty_az/0-0-0-14319

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
	PCC 17.16.160	SO_2	When solid fuel or oil is used 1.0 heat input per 3-hour average for installations which commenced construction/major modification prior to May 30, 1972 0.8 lbs/MMBtu heat input per 3-hour average for installations which commenced construction/major modification after May 30, 1972	1993	https://codelibrary.amlegal.com/codes/pimacounty/latest/pimacounty_az/0-0-0-13624
		NO_x	For steam power generating installations which commenced construction or major alteration after May 30, 1972, on a maximum 3-hour average calculated as nitrogen dioxide: 0.20 lbs/MMBtu heat input when gaseous fossil fuel is fired 0.30 lbs/MMBtu heat input when liquid fossil fuel is fired 0.70 lbs/MMBtu heat input when solid fossil fuel is fired		
Arizona – Maricopa County	Rule 322 Power Plant Operations		-Applies to combustion turbines, steam generating units, and cogen units - Exemption for low use units - <10% calendar year capacity factor (must have permit limit)	June 23, 2021	https://www.maricopa.gov/DocumentCenter/View/5256/Rule-322---Power-Plant-Operations-PDF?bidId=
		NOx	Existing steam generating units (commenced before 6/23/2021): 0.1 lb/MMBtu New steam generating units: 30 ppmvd @ 3% O2, gaseous fuel; 40 ppmvd for liquid fuel CTs, new and existing: 42 ppmvd at 15% O2 gaseous fuel; 65 ppmvd for liquid fuel (Allows case-by-case RACT alternative to be approved)		
		CO	400 ppmvd @ 15% O2 for CTs and 3% O2 for steam generating units		
		SO2	Liquid fuel must be 0.05% S or lower		
California	CA Reclaim Market	NO_x	5.286 MTons annual cap for list of entities in Appendix A of "Annual RECLAIM Audit Report for 2021Compliance Year" (304 entities)	1994	https://www.aqmd.gov/docs/default-source/reclaim/reclaim-annual-report/2021-reclaim-report.pdf?sfvrsn=6
		SO_2	2.219 MTons annual cap for list of entities in Appendix A of "Annual RECLAIM Audit Market Report for the 2021Compliance Year" (304 entities)		
	CA AB 32	CO_2	Power sector and Non-power Sector Cap in Million metric tons.	2012	Refer to Section 3.10.5 for details
CA – Bay Area AQMD	Reg 9, Rule 9	NO_X	NOx Emission Limits for gas turbines > 250 – 500 MM Btu/hr 0.43 lbs/MWhr or 9 ppmv > 500 MM Btu/hr 0.15 lbs/MWhr or 5 ppmv	2006	https://www.baaqmd.gov/~/media/dotgov/files/rules/reg-9-rule-9-nitrogen-oxides-and-carbon-monoxide-from-stationary-gas-turbines/documents/rg0909.pdf?la=en&rev=fed388c23f264d6ebd5e6e40096bdf79
	Reg 9, Rule 11	NO_x	NOx Emission Limits for Boilers with a Rated Heat Input Capacity Greater Than or Equal to 1.75 billion BTU/hour: 301.1 Gaseous Fuel: For gaseous fuel firing, nitrogen oxides (NOx) shall not exceed 10 ppmv, dry at 3 percent oxygen;	2000	https://www.baaqmd.gov/~/media/dotgov/files/rules/reg-9-rule-11-nitrogen-oxides-and-carbon-monoxide-from-utility-electric-power-generating-boilers/documents/rg0911.pdf?la=en&rev=cf79907f652d454c9b52a55ae3e95903
		NOx	NOx Emission Limits for Boilers with a Rated Heat Input Capacity Less Than 1.75 billion BTU/hour and Greater Than or Equal to 1.5 billion BTU/hour: Effective December 31, 2004, a person shall not operate an electric power generating steam boiler with a rated heat input less than 1.75 billion BTU/hour and greater than or equal to 1.5 billion BTU/hour unless the following conditions and emission limits are met: 303.1 Gaseous Fuel: For gaseous fuel firing, nitrogen oxides (NOx) shall not exceed 25 ppmv, dry at 3 percent oxygen;		
		CO	CO Emission Limits for Boilers with a Rated Heat Input Capacity Greater Than or Equal to 250 million BTU/hour:		

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
			310.1 During steady state compliance source tests, carbon monoxide (CO) shall not exceed 400 ppmv, dry at 3 percent oxygen, based on the test methods referenced in Section 9-11-602; 310.2 During normal operation (CEMS compliance monitoring), carbon monoxide (CO) shall not exceed 1000 ppmv, dry at 3 percent oxygen, based on a clock hour average		
CA – Colusa County APCD	Rule 251	NO_x	Gas Turbines rated > 0.3 MW: 42 ppmv @ 15% O_2 on a dry basis averaged over 3 hours, when gas fuel is used (Including natural, digester, and landfill) 65 ppmv @ 15% O_2 on a dry basis averaged over 3 hours, when oil fuel is used (Including kerosene, jet fuel, and distillate, with the sulfur content of the oil less than 0.05% by weight)	2002	https://www.countyofcolusa.org/DocumentCenter/View/11866/Rule-251-Determination-of-RACT-for-the-Control-of-Oxides-of-Nitrogen-from-Stationary-Gas-Turbines
	Rule 252	NO_x	Natural Gas-Fired, Rich-Burn Engines: 640 ppmv @ 15% O_2 on a dry basis, for engines rated greater than 50 bhp but less than 300 bhp 90 ppmv @ 15% O_2 on a dry basis, for engines rated greater than 300 bhp Natural Gas-Fired, Lean-Burn Engines: 740 ppmv @ 15% O_2 on a dry basis, for engines rated greater than 50 bhp but less than 300 bhp 150 ppmv @ 15% O_2 on a dry basis, for engines rated greater than 300 bhp	2002	https://www.countyofcolusa.org/DocumentCenter/View/11867/Rule-252-Stationary-Internal-Combustion-Engines
		CO	Natural Gas-Fired engines rated greater than 50 bhp: 4500 ppmv @ 15% O_2 on a dry basis		
	Rule 262	SO_x	0.2 percent by volume (2000 ppm) collectively calculated as SO_2	2002	https://www.countyofcolusa.org/DocumentCenter/View/11869/Rule-262-Sulfur-Oxides Applies to both EGUs and non-EGUs.
CA – Eastern Kern APCD	Rule 425	NO_x	Limits for stationary gas turbines >10MW: 9 ppm for gaseous fuel, 25 ppm for liquid fuel @15% O2 -Exception for Westinghouse W251B10 with an ATC prior to 1/1/1983: 25 ppm for gaseous fuel and 65 ppmv for liquid fuel	2021	http://kernair.org/Rule%20Book/4%20Prohibitions/425_Cogeneration_Gas_Turbine_Engines.pdf
	Rule 425.2	NO_x	Limits for boilers, process heaters > 5 MMBTU/hr and more than 90,000 therms annual heat input: 30 ppmv (or 0.036 lb/MMBTU) when operated on gaseous fuel; 40 ppmv (or 0.052 lb/MMBTU when operated on liquid fuel. -Exception for Union Iron Works CA B21841-68 and Combustion Engineering CA B35362-74 w an ATC prior to 1/1/1983: 70 ppmv for gaseous and 115 ppm for liquid	2021	http://kernair.org/Rule%20Book/4%20Prohibitions/425-2_Boilers_Steam_Generators_&_Process_Heaters.pdf
CA – Mojave Desert AQMD	Rule 1158 – Electric Power Generating Facilities	NOx	Combustion turbines >10 MW with SCR: (9 * Efficiency/25) ppm @15% O2 for gaseous fuel and 25 * E/25 for liquid fuel CTs>10 MW w/o SCR: (15 * efficiency/25) ppm for gaseous fuel and (42 * E/25) for liquid fuel (efficiency cannot be less that 25 percent)	1997	https://www.mdaqmd.ca.gov/home/showpublisheddocument/1291/636341759986130000
	Rule 431	CO	Electric power boiler:	2001	

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
CA – Monterey Bay APCD			400ppm (60-consecutive minute average) – during steady state compliance test 1000ppm (1 hour clock-hour average at 3% O_2 on a dry basis) – during normal operations		https://ww2.arb.ca.gov/sites/default/files/classic/technology-clearinghouse/rules/RuleID1660.pdf Applies to electric power boilers
		Ammonia	Electric power boiler: 10ppm (60-consecutive minute average) – during steady state compliance test		
		NO_x	Electric power boiler (NO_X limits based on 1-hour average at 3% O2 on a dry basis): (1) If fired with natural gas: 90 ppm if >400 gross MW; 450 lb/hr if ≤ 400 gross MW; If fired with fuel oil: 225 ppm; (2) 10 ppm if fired with natural gas, or 25 ppm if fired with fuel oil. (3) May 1 through October 31, total NOx from all boiler units shall not exceed an average of 9.64 tons per day; (4) All boilers combined at the power plant shall not exceed 0.3 lbs/MMBtu During fuel switching periods: • First 6 hours – applicable fuel oil limit; After 6 hours – limit is calculated using formula in Section 3.6.1 of this rule		
CA- North Coast Unified APCD	Rule 104	PM	Steam generating power plants: 0.10 lb/MMBtu, or any other specific applicable permit limitation, whichever is more restrictive	1982	https://www.ncuaqmd.org/files/70b9a2edd/Rule+104.pdf
CA- Placer County APCD	Rule 233 – Boilers/Steam Generators	NO_X	Compliance limit (ppmv @ 12% CO_2) for biomass boilers or steam generator: (a) Circulating fluidized bed (<500 MMBtu/hr) - 115 ppmv (averaged over 3 hrs) and 68 ppmv (averaged over 24 hrs). (b) Stoker (<500 MMBtu/hr) - 115 ppmv (averaged over 3 hrs) and 68 ppmv (averaged over 24 hrs).	2012	https://www.placerair.org/DocumentCenter/View/2205/Rule-233-PDF
		CO	Compliance limit (ppmv @ 12% CO_2) for biomass boilers or steam generator: (a) Circulating fluidized bed (<500 MMBtu/hr) - 400 ppmv (averaged over 3 hrs). (b) Stoker (<500 MMBtu/hr) - 1000 ppmv (averaged over 3 hrs).		
	Rule 250 – Stationary Gas Turbines	NO_X	Compliance limit (ppm @ 15% O_2 averaged over 1 hr over 4 consecutive 15-minute averages) for stationary gas turbines: (a) Gas (natural, digester, and landfill gases) – (iii) ≥ 10 MW – 9 ppm (b) Oil (kerosine, jet, and distillate) – (iii) ≥ 10 MW – 25 ppm	2015	https://www.placerair.org/DocumentCenter/View/2220/Rule-250-PDF
CA – Sacramento Metro AQMD	Rule 413	NOx	Natural gas fired combustion turbine - 15 ppm@15% O2 for units > 10 MW (no SCR) 9 ppm@15% O2 for units > 10 MW (w SCR)	2005	The rule does not require the use of SCR, but establishes a limit when units have installed them.

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
					https://ww2.arb.ca.gov/sites/default/files/classic/technology-clearinghouse/rules/RuleID3589.pdf
CA – San Diego APCD	Rule 69	NOx	Applies to existing and new electrical generating steam boilers - Existing units subject to aggregate limit of 650 tons/yr on and after January 1, 2005 0.15 lb/MWh (natural gas), 0.40 lb/MWh (fuel oil) if unit not subject to aggregate limit	1995	https://ww2.arb.ca.gov/sites/default/files/classic/technology-clearinghouse/rules/RuleID3002.pdf
	Rule 69.3.1	NOx	Natural gas fired combustion turbine - 15 x (E/25) ppm@15% O_2 for units > 10 MW (no SCR) 9 x (E/25) ppm@15% O_2 for units > 10 MW (w SCR)	2021	https://ww2.arb.ca.gov/sites/default/files/classic/technology-clearinghouse/rules/RuleID4832.pdf The (E/25) term represents an adjustment factor for thermal efficiency; a turbine with a thermal efficiency of < 25% is assigned an E value of 25
CA – San Joaquin Valley APCD	Rule 4306	NOx	Gas-fired Boilers >75 MMBtu/hr, 5 ppm @15% O_2 or 0.0061 lb/MMBtu Liquid-fired Boilers>75 MMBtu/hr 40 ppm @15% O_2 or 0.052 lb/MMBtu	12/31/2023	https://www.valleyair.org/rules/currntrules/r4306.pdf Applies to EGUs and non-EGUs; unclear if any EGUs subject
		CO	400 ppmv (gas and liquid fuels)	12/31/2023	
	Rule 4320	NOX	Gas or liquid fuel-fired boilers >75 MMBtu/hr, 2.5 ppm @15% O_2 OR pay a fee to avoid this limit	12/31/2023	https://www.valleyair.org/rules/currntrules/r4320.pdf, Applies to EGUs and non-EGUs; unclear if any EGUs subject
	Rule 4703	NOX	Gas-fired combustion turbines >10 MW, combined cycle: 3 ppm for newer, rest 5 ppm @15% O_2; Gas-fired simple cycle >10 MW: if permit limit below 200 hr/yr, then 25 ppm; if above 200 hrs then 5 ppm for older and 3 ppm for newer	~2012	https://www.valleyair.org/rules/currntrules/r4703.pdf Applies to EGUs and non-EGUs; likely existing EGUs subject to this rule
	Rule 4352	NOX	Biomass or other solid fuel (except MSW): 65 ppm @3%O_2; 30-day average MSW: 110 ppm 24-hr avg; 90 ppm 12 mo average	1/1/2024	https://www.valleyair.org/rules/currntrules/r4352_3.pdf Applies to EGUs and non-EGUs.
		CO	400 ppm @3%O_2; 24-hr average	1/1/2024	
		PM10	MSW: 0.04 lb/MMBtu or 0.02 gr/dscf @ 12%CO_2 Biomass or other solid fuel (except MSW): 0.03 lb/MMBtu	1/1/2024	
		SOX	MSW: 0.03 lb/MMBtu or 12 ppm @12%02 12 mo average; 0.064 lb/MMBtu or 25 ppm @12% O224-hr avg Biomass or other solid fuel (except MSW): 0.02 lb/MMBtu 30-day average; 0.035 lb/MMBtu 24-hr average	1/1/2024	
CA – South Coast AQMD	Rule 1135	NOX	Boilers: 5 ppm@ 3%O_2 Combined Cycle, and duct burner: 2 ppm @15%O_2 Simple Cycle: 2.5 ppm -See specific requirements for city of Glendale prior to 1/1/2024 -Once through cooling units exempt if will retire by 12/31/2029 -Low use gas turbines installed prior to 11/2/2018 are exempted if annual capacity factor is less than 10%, 3yr rolling average AND less than 25% each calendar year, must retain existing applicable emissions limits	Currently 1/1/2024 (proposed amendment for 4/1/2024 to provide a few sources extra time)	https://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1135.pdf?sfvrsn=4 Rule is for EGUs

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			-low use exemption for boilers is <1% capacity factor on 3yr rolling basis and <2.5% each calendar year		
	Rule 1110.2	NOX	New Engines that are EGUs 0.070 lb/MW-hr or 2.5 ppm @15%O2	2019	https://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1110-2.pdf?sfvrsn=4; Rule for EGUs and non-EGUs, but has EGU specific requirements
		VOC	New Engines that are EGUs 0.10 lb/MW-hr or 10 ppm	2019	
		CO	New Engines that are EGUs 0.20 lb/MW-hr or 12 ppm	2019	
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 lbs/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	Arapahoe 3, Cherokee 1-3, Cameo 1 & 2, Valmont 5, W N Clark 55 & 59 units have retired. Arapahoe 4 &Cherokee 4 units have retired. Hayden 1 has SCR, Hayden 2 retired.
		Hg	Comanche Units 1, 2, and 3 Combined Hg Limit - 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	
	SB23-198	CO_2	Directs Air Quality Control Commission to adopt rules to pursue reductions in greenhouse gasses from electric utilities by at least 47% by 2027 and 80% by 2030 relative to the 2005 levels.	2027	
Connecticut	Executive Order 19 and Regulations of Connecticut State Agencies (RCSA) section 22a-174-22e*	NO_x	0.15 lbs/MMBtu rate limit for all fossil units > 15 MW (Non-ozone season only) Ozone season (Pre June 1, 2023) Daily average limits for EGU Boilers: Gas: 0.20 lbs/MMBtu (non-cyclone boilers) 0.30 lbs/MMBtu (cyclone boilers) Residual oil: 0.25 lbs/MMBtu (non-cyclone boilers) 0.43 lbs/MMbtu (cyclone boilers) Other oil: 0.20 lbs/MMBtu (non-cyclone boilers) 0.43 lbs/MMbtu (cyclone boilers) Coal: 0.28 lbs/MMBtu Daily average limits for simple cycle combustion turbines: Gas-fired: 55 ppm Oil-fired: 75ppm Daily average limits for combined cycle combustion turbines: Gas-fired: 42 ppm Oil-fired: 65 ppm	2003	Daily average limits shown are "Phase 1" limits, which began on June 1, 2018, and remain in effect until June 1. 2023, at which time more stringent limits take effect. *RCSA section 22a-174-22e was effective on 12/22/16 and replaced RCSA section 22a-174-22 (repealed on 6/1/19). As of July 1, 2021, Connecticut no longer has any coal EGUs.

<table>
<tr><th>State/Region</th><th>Bill</th><th>Emission Type</th><th>Emission Specifications</th><th>Implementation Status</th><th>Notes</th></tr>
<tr><td rowspan="4"></td><td></td><td></td><td>Ozone Season (June 1, 2023 onwards)

Daily average limits for EGU Boilers:
Gas: 0.10 lbs/MMBtu
Residual oil: 0.20 lbs/MMBtu
Other oil: 0.10 lbs/MMBtu
Coal: 0.12 lbs/MMBtu

Daily average limits for simple cycle combustion turbines:
Gas-fired: 40 ppm
Oil-fired: 50 ppm

Daily average limits for combined cycle combustion turbines:
Gas-fired: 25 ppm
Oil-fired: 42 ppm</td><td rowspan="2"></td><td rowspan="2"></td></tr>
<tr><td>Executive Order 19, RCSA section 22a-174-19(a) & Connecticut General Statutes (CGS) section 22a-198</td><td>SO_2</td><td>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 facility</td></tr>
<tr><td>CGS section 22a-199</td><td>Hg</td><td>90% removal of Hg content of fuel or 0.6 lbs/TBtu quarterly basis for all coal-fired units</td><td>2008</td><td>As of July 1, 2021, Connecticut no longer has any coal EGUs.</td></tr>
<tr><td>CGS section 22a-200a</td><td>CO_2</td><td>The state shall reduce the level of emissions of greenhouse gas: not later than January 1, 2040 to a level of zero percent from electricity supplied to electric customers in the state.</td><td>2040</td><td></td></tr>
<tr><td rowspan="4">Delaware</td><td>Regulation 1148: Control of Stationary Combustion Turbine EGU Emissions</td><td>NO_x</td><td>0.34 lb/MMBTU ozone season (88 ppmvd) for stationary, liquid fuel fired CT EGUs >1 MW
0.15 lb/MMBTU ozone season (42 ppmvd) for stationary, gas fuel fired CT EGUs >1 MW</td><td>2009</td><td></td></tr>
<tr><td rowspan="3">Regulation No. 1146: Electric Generating Unit (EGU) Multi-Pollutant Regulation</td><td>NO_x</td><td>0.125 lbs/MMBtu rate limit of NO_x annually for all coal and residual-oil fired units > 25 MW (2012)</td><td rowspan="2">2009 and 2012</td><td rowspan="3">The following units have specific NO_x, SO_2, and Hg annual caps in MTons:
Edge Moor 3 - NO_x: 0.773, SO_2: 1.391, Hg: 0.0000083 (2012), Hg: 0.0000033 (2013 onward)
Edge Moor 4 - NO_x: 1.339, SO_2: 2.41 Hg: 0.0000144 (2012), Hg: 0.0000057 (2013 onward)
Edge More 5 - NO_x: 1.348, SO_2: 2.427
(Retired) Indian River 3 – NO_x: 0.977, SO_2: 1.759, Hg: 0.0000105 (2012), Hg: 0.0000042 (2013 onward)
(Retired) Indian River 4 - NO_x: 2.032, SO_2: 3.657 Hg: 0.0000219 (2012), Hg: 0.0000087 (2013 onward)
(Retired) McKee Run 3 - NO_x: 0.244, SO_2: 0.439
(Note that both Indian River 3 and McKee Run 3 have retired; Indian River 3 in 2014 and McKee Run 3 in 2021.)</td></tr>
<tr><td>SO_2</td><td>0.26 lbs/MMBtu annual rate limit for coal fired units > 25 MW (2012).
Residual oil fired units have a limit on fuel oil sulfur content of 0.5% (2009).</td></tr>
<tr><td>Hg</td><td>2012: 1.0 lb/TBTU Hg emissions rate limit or 80% reduction from baseline emissions rate for all coal units > 25 MW
2013 onwards: 0.60 lb/TBTU Hg emissions rate limit or 90% reduction from baseline emissions rate for all coal units > 25 MW</td><td>2012 and 2013</td></tr>
</table>

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
	Regulation 1108: Distillate Fuel Oil rule	SO_2	15ppm by weight sulfur in fuel limit for all distillate fuel oil sold or combusted in Delaware	2016	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 NO_x 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 for 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)	
	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	
	Illinois Pollution Control Board - Amendments To 35 Ill. Adm. Code 225.233, Multi-Pollutant Standard	NO_x – Ozone Season	The Board incorporates the amendments suggested by the IEPA in its testimony and comments. The IEPA proposed mass-based caps of 11,500 tons for NO_x for the ozone season.	2019	https://pcb.illinois.gov/documents/dsweb/Get/Document-100685 The amendments also require reduction of at least 2,000 megawatts (MW) of electric generation by coal fired EGUs in the MPS no later than
		NO_x	The Board incorporates the amendments suggested by the IEPA in its testimony and comments. The IEPA proposed mass-based caps of 19,000 tpy for NO_x.	2019	

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
		SO_2	The Board incorporates the amendments suggested by the IEPA in its testimony and comments. The IEPA proposed mass-based caps of 34,500 tpy for SO_2.	2019	December 31, 2019 and adjust the allocation amounts for transfers, permanent shutdown, and temporary shutdown; and clarify the language of the rule.
	Public Act 102-0662 Sec. 9.15	CO2	Private Coal and Oil Units: Retire by 2030 Private Gas Units: Reduce emissions by 50% by 2035, Retire 2045 Public Coal Units: Reduce emissions by 45% by 2035 or retire a unit, Retire 2050 Public Gas Units: Retire by 2045	2021	https://www.ilga.gov/legislation/publicacts/102/PDF/102-0662.pdf
	Public Act 102-0662 Sec.1.5	CO2	State policy to transition to 100 percent clean energy by 2050	2021	https://www.ilga.gov/legislation/publicacts/102/PDF/102-0662.pdf
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 SO_2/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 for Nearman Unit 1: 0.26 lbs/MMBtu	2012	
	NO_x Emission Reduction Rule, K.A.R. 28-19-713a. (Quindaro Unit 2)	NO_x	Annual rate limit for Quindaro Unit 1: 0.20 lbs/MMBtu	2012	Unit has retired.
Louisiana	Title 33 Part III - Chapter 22, Control of Nitrogen Oxides	NO_x	For units >/= 80 MMBtu/hr, rate limit (Ozone season): Coal-fired: 0.21 lbs/MMBtu Oil-fired: 0.18 lbs/MMBtu All others (gas or liquid): 0.1 lbs/MMBtu	2005	Applicable for all units in Baton Rouge Nonattainment Area & Region of Influence.

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
			Stationary Sources >/= 10 MMBtu/hr, rate limit (Ozone season): Oil-fired: 0.3 lbs/MMBtu Gas-fired: 0.2 lbs/MMBtu		Willow Glenn, located in Iberville, obtained a permit that allows its gas-fired units to maintain a cap. These units are separately modeled. Willow Glenn units have retired.
	Title 33, Part III - Chapter 15, Emission Standards for Sulfur Dioxide	SO_2	1.2 lbs/MMBtu for all single point sources that emit or have the potential to emit 5 tons or more of SO_2	2005	
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] 0.0015% sulfur for distillate	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 - 16.667 MTons The ozone season NOx tonnage limitations: 5/1/2009-9/30/2011 - 8.9 MTons 5/1/2012 onward - 7.337 MTons	2009	
		SO_2	1/1/2010-12/31/2012 - 48.618 MTons 1/1/2013 onward - 37.235 MTons		
		Hg	1/1/2010-12/31/2012 - 80% removal of Hg content of fuel for 15 specific existing coal steam units 1/1/2013 onward - 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	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	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. (Brandon Shores Units 1 and 2, H. A. Wagner Units 3 has SCR.) 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.

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
			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. Affected EGUs equipped with a fluidized bed combustors (AES Warrior Run) shall meet a 24-hr block average annual NOx emission rate of 0.10 lbs/MMBtu		The Crane units were sold on or around 2/16/2016 and are no longer part of the Raven System. AES Warrior Run
Massachusetts	310 CMR 7.19 NOx RACT II	NOx	Large Boilers- 100 MMBtu or greater: Coal tangential and face fired 0.12 lbs/MMBtu. Greater than 250 MMBtu oil tangential or face fired: 0.15 lbs/MMBtu Tangential gas 0.08 lbs/MMBtu Boilers between 100 MMBtu and less than 250 MMBtu burning oil or oil and gas: 0.15 lbs/MMBtu or for Boilers burning only gas 0.06 lbs/MMBtu Combustion Turbines: Combined cycle turbines -25 ppmvd when firing gas, 42 ppmvd when firing oil. Simple Cycle turbines- 40 ppmvd when firing gas, 50 ppmvd firing oil 2020 RICE- rich burn gas fired, and lean burn gas fired 1.5 grams per bhp-hr. Lean burn oil fired or dual fuel, 2.3 grams per bhp-hr.	2020	Boilers and turbines with an annual capacity factor less than 10% averaged over the most recent three-year consecutive period not subject to the new more stringent emission standards. Engines that operated less than 1,000 hours during any consecutive 12-month period not subject to the more stringent emission standards
		CO	Boilers: 200 ppmvd Turbines: Combined cycle 50 ppmvd, simple cycle 100 ppmvd Engines: no change	2020	
	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	Brayton Point, Salem Harbor, MT Tom, and Mystic Generating Station have permanently retired.
		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		
	310 CMR 7.05	SO_2	Sulfur in Fuel Oil Rule requires the use of 0.5% sulfur residual oil [0.52 lbs/MMBtu] after July 1, 2018 for units greater than 250 MMBtu energy	2014	Fuel rule modeled through unit emission rates

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
		Sulfur in fuel	input; all residual oil units except for those located in the Berkshire APCD are affected.		
			Distillate oil- 0.05% (500 ppm) July 1, 2014-June 30, 2018 Distillate oil 0.0015% (15 ppm) on and after July 1, 2018	2014	
	310 CMR 7.74: Reducing CO2 Emissions from Electricity Generating Facilities	CO_2	The regulation sets the existing facility aggregate CO_2 emissions limit, and new facility aggregate CO_2 emissions limit as the following: Total Aggregate CO_2 Emissions Limits - The total aggregate CO_2 emissions limit for 2018 and 2019 are 9,149,979 metric tons of CO_2 and 8,731,175 metric tons of CO_2 respectively. The total aggregate CO_2 emissions limit declines by 223,876 metric tons each year thereafter until it reaches 8,507,299 metric tons of CO_2 in 2020 and 1,791,019 metric tons of CO_2 in 2050.	2018	https://www.mass.gov/doc/fact-sheet-massdep-electricity-sector-regulations/download
	MGL c.21N Sections 3(b) and 4(h)	GHGs	A 2050 statewide emissions limit that achieves at least net zero statewide greenhouse gas emissions; provided, however, that in no event shall the level of emissions in 2050 be higher than a level 85 percent below the 1990 level." and "The interim 2030 statewide greenhouse gas emissions limit shall be at least 50 percent below the 1990 level, and the interim 2040 statewide greenhouse gas emissions limit shall be at least 75 percent below the 1990 level.	2030	https://malegislature.gov/Laws/GeneralLaws/PartI/TitleII/Chapter21N/Section3 https://malegislature.gov/Laws/GeneralLaws/PartI/TitleII/Chapter21N/Section4
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	
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	Schiller Unit 5 is no longer subject because PSNH installed a new unit. 80% reduction from baseline.

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
					Baseline = 268 lbs/yr. 80% reduction = 53.6 lbs/yr
	Env-A 1300, NOx RACT	NOx	24-hour limits: Merrimack Units 1 & 2 - 0.22 lbs NO_x/MMBtu	2018	There are additional limits of 4.0 and 11.5 tons per day on any calendar day during which a startup or shutdown occurs.
			24-hour limits: Newington Unit 1 – 0.25 lbs NO_x/MMBtu	1994	Originally Env-A 1211, but this limit has been in place since 1994
	Env-A 3200, NOx Budget Trading 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	2006	Applies to Merrimack Units 1 & 2, Merrimack Combustion Turbines 1 & 2, Schiller Units 4 & 6, Schiller Combustion Turbine 1, Newington Unit 1, White Lake Turbine, Lost Nation Turbine, Granite Ridge Energy, and Newington Energy.
	Env-A 2900, Multiple Pollutant Annual Budget Trading and Banking Program	NO_x	Emission Caps: 3.64 MTons annual cap for Merrimack Units 1 & 2, Newington Unit 1, and Schiller Units 4 through 6	2004	Schiller Unit 5 is no longer subject because PSNH installed a new unit.
		SO_2	7.29 MTons annual cap for Merrimack Units 1 & 2, Newington Unit 1, and Schiller Units 4 through 6		
	Env -A 2300 - Mitigation of Regional Haze	SO_2	94% SO_2 control from Merrimack Units 1 & 2 combined 30-boiler operating day rolling average; 0.50 lb SO_2/MMBtu 30 day rolling average at Newington Unit 1	2013	
New Jersey	N.J. A. C. Title 7, Chapter 27, Subchapter 9, Low Sulfur Fuel Rule	SO_2	15 ppm for No. 2 and lighter fuel 2,500 ppm for No. 4 fuel	July 1 2016 (No. 2. And lighter), July1,2014 (No. 4)	
	N.J. A. C. Title 7, Chapter 27, Subchapter 10.2	SO_2	0.15 (30 day rolling average) lbs/MMBtu and 0.25 (24-hour) 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 3	NO_x	1.50 lbs/MWh for Boilers firing coal and serving electric generating units 2.00 lbs/MWh for Boilers firing heavier than No. 2 fuel oil and serving electric generating units 1.00 lbs/MWh for Boilers firing No. 2 and lighter fuel oil and serving electric generating units 1.00 lbs/MWh for Boilers firing gas only and serving electric generating units	05/01/2015	Operative on and after May 1, 2015
	N.J. A. C. Title 7, Chapter 27, Subchapter 19, Table 7; High Electricity demand Day (HEDD) unit	NO_x	1.00 lbs/MWh for gas-burning simple cycle combustion turbine units 1.60 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 1.20 lbs/MWh for oil-burning combined cycle CT or regenerative cycle CT units 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	2007	Not modeled as these rates are applicable only during HEDD.

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
			operation on high electricity demand days, regardless of the fuel combusted, unless combusting gaseous fuel is not possible due to gas curtailment."		
New Jersey	N.J. A. C. Title 7, Chapter 27F, Control and Prohibition of Carbon Dioxide Emissions	CO_2 (Co-benefits of NOx, SO_2, PM and HAPs)	1,700 lbs of CO_2/MWh of gross energy output on or before 6/1/2024 1,300 lb of CO_2/MWh of gross energy output on or before 6/1/2027 1,000 lb of CO_2/MWh of gross energy output on or before 6/1/2035	2023	N.J.A.C. 7:27F-2.5(d) available at https://dep.nj.gov/wp-content/uploads/rules/rules/njac7-27f.pdf
New York	Part 222	NOx	Distributed Generation Sources This rule applies to owners and operators of distributed generation sources classified as economic dispatch sources located in the New York City metropolitan area with a maximum output rating of 200 horsepower or greater where the potential to emit NOx at a facility is less than 25 tons per year. Beginning May 1, 2021, the first phase will be implemented. combustion turbines, compression ignition engines and lean-burn natural gas-fired engines must be of model year 2000 or newer OR must have a NOx emission rate less than or equal to 2.96 pounds per megawatt-hour as certified in writing by a professional engineer. Also, effective May 1, 2021, rich-burn natural gas-fired engines must be equipped with three-way catalyst emission controls (*a control technology that reduces NOx, VOC and CO emissions from rich burn engines.*) Beginning May 1, 2025, the second phase will be implemented. For combustion turbines firing natural gas, presumptive NO_X emission limits are reduced to 25 parts per million on a dry volume basis corrected to 15 percent oxygen. For combustion turbines firing oil, presumptive NO_X emission limits are reduced to 42 parts per million on a dry volume basis corrected to 15 percent oxygen. For spark ignition engines firing natural gas, presumptive NO_X emission limits are reduced to 1.0 grams per brake horsepower-hour. For compression-ignition engines firing distillate oil with nameplate rating less than 750 hp, presumptive NO_X emission limits are reduced to 0.30 grams per brake horsepower-hour. For compression-ignition engines firing distillate oil with nameplate rating greater than or equal to 750 hp, presumptive NO_X emission limits are reduced to 0.50 grams per brake horsepower-hour.	2021 and 2025	https://govt.westlaw.com/nycrr/Browse/Home/NewYork/NewYorkCodesRulesandRegulations?guid=I06948fa0c87f11e68e78e7873f673e4d&originationContext=documenttoc&transitionType=Default&contextData=(sc.Default)

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
New York	Subpart 227-3	NO_x	Ozone Season NO_x Emission Limits for Simple Cycle and Regenerative Combustion Turbines: For SCCTs with a nameplate capacity of 15 megawatts or greater that inject power into the transmission or distribution systems: Beginning 5/1/2023, the first phase of NO_x emission limits will be implemented during the ozone season and SCCTs will be limited to averaging with other SCCTs, storage or renewable energy resources. The first phase of emission limits will be: All SCCTs: 100 ppmvd Beginning 5/1/2025, the second and final phase of NO_x emission limits will be implemented during the ozone season as follows: Gaseous fuels: 25 ppmvd Distillate oil or other liquid fuel: 42 ppmvd Notes: Parts per million on a dry volume basis at fifteen percent oxygen.	2023 and 2025	https://www.dec.ny.gov/regulations/116175.html
New York	Part 225	SO_2	Owners and/or operators of any stationary combustion installation that fires solid fuels are limited to the firing of solid fuel with a sulfur content listed in the table below on or after July 1, 2014: Solid fuel (pounds of sulfur/millionBtu) New York City: 0.2 MAX. Nassau, Rockland and Westchester Counties: 0.2 MAX. Suffolk County: Towns of Babylon, Brookhaven, Huntington, Islip, and Smith Town: 0.6 MAX. Erie and Niagara Counties: 1.7 MAX, 1.4 AVG. Remainder of State: 2.5 MAX, 1.9 AVG Owners and/or operators of a stationary combustion installation that fires distillate oil other than number two heating oil are limited to the purchase of distillate oil with 0.0015 percent sulfur by weight or less on or after July 1, 2014. Owners and/or operators of any stationary combustion installation that fires distillate oil including number two heating oil are limited to the firing of distillate oil with 0.0015 percent sulfur by weight or less on or after July 1, 2016.	2014 and 2016	
	Part 243	NO_x	5,135 tons NO_x Ozone season budget for fossil fuel units greater than 25 MW.	2017	
	Part 244	NO_x	16,081 tons NO_x annual budget for fossil fuel units greater than 25 MW.	2017	
	Part 245	SO_2	27,556 tons SO_2 annual budget for fossil fuel units greater than 25MW	2017	
	Part 237	NO_x	39.91 MTons non-ozone season cap for fossil fuel units > 25 MW	2004	Repealed
	Part 238	SO_2	131.36 MTons 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.	2010	https://govt.westlaw.com/nycrr/Browse/Home/NewYork/NewYorkCodesRulesandRegulations?guid=Ic3039690b5

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
			0.60 lbs/TBtu annual rate limit for all coal units > 25 MW developed after November 15, 1990 for new units and existing facilities – effective January 1, 2015.		a011dda0a4e17826ebc834&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 for very large boilers >250 MMBtu/hr on or after July 1, 2014 Gas only, tangential & wall fired: 0.08 lbs/MMBtu Gas/oil tangential & wall fired: 0.15 lbs/MMBtu; cyclone: 0.2 lbs/MMBtu Coal Wet Bottom, tangential & wall fired: 0.12 lbs/MMBtu; cyclone: 0.2 lbs/MMBtu Coal Dry Bottom, tangential & wall fired: 0.12 lbs/MMBtu; stokers: 0.08 lbs/MMBtu	2004	
			Annual rate for large boilers between 100 and 250 MMBtu/hr on or after July 1, 2014; Gas Only: 0.06 lbs/MMBtu Gas/Oil: 0.15 lbs/MMBtu Pulverized Coal: 0.20 lbs/MMBtu Coal (Overfeed Stoker/FBC): 0.8 lbs/MMBtu		
			Annual rate for mid-size boilers between 25 and 100 MMBtu/hr on or after July 1, 2014; Gas Only: 0.05 lbs/MMBtu Distillate Oil/Gas: 0.08 lbs/MMBtu Residual Oil/Gas: 0.20 lbs/MMBtu		
			Combined cycle and cogeneration combustion turbines must have an approved case by case RACT determination from the Department by July 1, 2014. Simple cycle combustions turbines 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.		
	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 2019 allocation year. (b) The CO_2 Budget Trading Program base budget is 30,435,778 tons, for the 2020 allocation year. (c) The CO_2 Budget Trading Program base budget is 29,056,270 tons, for the 2021 allocation year. (d) The CO_2 Budget Trading Program base budget is 28,175,777 tons for the 2022 allocation year. (e) The CO_2 Budget Trading Program base budget is 27,295,284 tons for the 2023 allocation year. (f) The CO_2 Budget Trading Program base budget is 26,414,791 tons, for the 2024 allocation year. (g) The CO_2 Budget Trading Program base budget is 25,534,298 tons, for the 2025 allocation year. (h) The CO_2 Budget Trading Program base budget is 24,653,805 tons, for the 2026 allocation year. (i) The CO_2 Budget Trading Program base budget is 23,773,312 tons, for the 2027 allocation year.	2020	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=Idb97d060db eb11dd9768bd0e013d693a&originationContext=documenttoc&transitionType=Default&contextData=%28sc.Default%29

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
			(j) The CO_2 Budget Trading Program base budget is 22,892,819 tons, for the 2028 allocation year. (k) The CO_2 Budget Trading Program base budget is 22,012,326 tons, for the 2029 allocation year. (l) The CO_2 Budget Trading Program base budget is 21,131,833 tons, for the 2030 allocation year and each succeeding allocation year.		
	Part 251 CO_2 Performance Standards for Major Electric Generating Facilities	CO_2	Owners and operators of major electric generating facilities (those which sell power to the grid and utilize boilers, combustion turbines, waste to energy sources, and/or stationary internal combustion engines to produce electricity with a generating capacity of at least 25 MW) that provide more than 10 percent of their annual electric output to the grid must meet CO_2 emission rates. For New Sources and modified existing sources that are boilers permitted to fire at greater than 70% fossil fuel, combined cycle combustion turbines, or stationary internal combustion engines that fire only gaseous fuels are required to meet an emission rate of 925 lbs. of CO_2 per MWh gross electrical output or 160 lbs. of CO_2 per million BTU of input For new or modified simple cycle turbines or stationary internal combustion engines that fire either liquid and gaseous fuel simultaneously are required to meet an emission rate of 1450 lbs. of CO_2 per MW hour gross electrical output or 160 lbs. of CO_2 per million BYU of input Non-Modified Existing sources are required to meet an emission rate of 1800 lbs. of CO_2 per MW gross electrical output or 180 lbs. of CO_2 per million BTU of input for each fossil fuel combusted	2020	
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	
	NCAC 02D .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	NC rule expired effective February 1, 2016, because MATS rule was vacated https://www.deq.nc.gov/about/divisions/air-quality/air-quality-planning/air-quality-rules-regulations/rules/section-2500-mercury-rules-electric-generators-expired
	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	Expired effective February 1, 2016, because MATS rule was vacated
	North Carolina SL 2021-165 (House Bill 951)	CO_2	Requires NC Utilities Commission to achieve 70% carbon emissions reduction from 2005 levels by 2030 and achieve carbon neutrality by 2050.	2030	Duke Energy is expected to release in Sept. 2023 its Integrated Resource Plan supporting implementation of SL 2021-165.
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	

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	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	No existing coal units in Oregon.
	Oregon Utility Mercury Rule - Potential Units	Hg	25 lbs limit for all potential coal units > 25 MW	2009	
	Oregon House Bill 2021	CO_2	Retail electricity providers are to reduce greenhouse gas emissions associated with electricity sold to consumers to 80% below baseline emission levels by 2030, 90% below baseline levels by 2035 and 100% below baseline levels by 2040. No new emitting fossil builds.	2030	
Pennsylvania	PA RACT	NO_x	For SCR equipped coal units, the NO_x emission rate limit (lb/MMBtu) will be based on a 30-day rolling average and will apply at all times even during operations when exhaust temperatures are too low for the SCR to operate or operate optimally. For facilities with multiple units, the rate limit will be based on the weighted average rate by the best performing unit. For these units a unit-specific daily mass emission limit is also placed where the limit is the product of the facility wide 30-day rolling average and each unit's heat input maximum permitted rate capacity.	2022	
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: 84.50 in 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 lbs/MMBtu heat input Coal fired units: 0.165 lbs/MMBtu heat input Stationary gas turbines: 0.14 lbs/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		

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
			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% 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	$1.6/Tonne cost (2004$) 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	
	Washington State SB5126	CO_2	Establishes a cap-and-trade program for greenhouse gases to be implemented by the Department of Ecology.	2028	

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			Updated statewide emissions reduction limits to 95% reduction below 1990 levels by 2050, with interim limit of 45% below 1990 levels by 2030 and 70% below 1990 levels by 2040.		
Wisconsin	NR 428 Wisconsin Administration Code	NO_x	Annual rate limits for coal fired boilers > 1,000 MMBtu/hr: Wall fired, tangential fired, cyclone fired, and fluidized bed: 0.10 lbs/MMBtu (2013 onward) Arch fired: 0.18 lbs/MMBtu (2009 onward)	2009	
			Annual rate limits 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: 0.17 lbs/MMBtu (2013 onward); if heat input is lesser: Tangential fired: 0.15 lbs/MMBtu (2009 onward) Cyclone fired: 0.15 lbs/MMBtu (2013 onward) Fluidized bed: 0.10 lbs/MMBtu (2013 onward) Arch fired: 0.18 lbs/MMBtu (2009 onward)		
			Annual rate limits for coal fired boilers between 250 and 500 MMBtu/hr: Same as for coal fired boilers between 500 and 1000 MMBtu/hr, in addition; Stoker Fired: 0.20 lbs/MMBtu		
			Annual rate limits for coal fired boilers between 50 and 250 MMBtu/hr: Same as for coal boiled between 500 and 1000 MMBtu/hr, in addition; Stoker Fired: 0.25 lbs/MMBtu		
			Annual rate limits for Combustion Turbines: Natural gas CTs > 50 MW: 0.11 lbs/MMBtu Distillate oil CTs > 50 MW: 0.28 lbs/MMBtu Biologically derived fuel CTs > 50 MW: 0.15 lbs/MMBtu Natural gas CTs between 25 and 49 MW: 0.19 lbs/MMBtu Distillate oil CTs between 25 and 49 MW: 0.41 lbs/MMBtu Biologically derived fuel CTs between 25 and 49 MW: 0.15 lbs/MMBtu		
			Annual rate limits for Combined Cycle: Natural gas CCs > 25 MW: 0.04 lbs/MMBtu Distillate oil CCs > 25 MW: 0.18 lbs/MMBtu Biologically derived fuel CCs > 25 MWs: 0.15 lbs/MMBtu Natural gas CCs between 10 and 24 MW: 0.19 lbs/MMBtu		
	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 80% reduction in fuel, or 0.0130 lbs per GW-hr from CY2018 – CY 2020 90% reduction in fuel, or 0.0080 lbs per GW-hr from January 1, 2021 onwards	2015	Alternative already modeled in IPM