

Updates to EPA Base Case 2009 ARRA Using the Integrated Planning Model (IPM)

This document catalogs the list of updates in EPA Base Case 2009 ARRA using the Integrated Planning Model (IPM).

IPM and EPA Modeling Applications Using IPM:

EPA uses the Integrated Planning Model (IPM[®]) to analyze the projected impact of environmental policies on the electric power sector in the 48 contiguous states and the District of Columbia. Developed by ICF Resources, Inc. and used to support public and private sector clients, IPM is a multi-regional, dynamic, deterministic linear programming model of the electric power sector. It provides forecasts of least-cost capacity expansion, electricity dispatch, and emission control strategies for meeting electricity demand, environmental, transmission, dispatch, and reliability constraints. IPM can be used to evaluate the cost and emissions impacts of proposed policies to limit emissions of sulfur dioxide (SO₂), nitrogen oxides (NO_x), carbon dioxide (CO₂), and mercury (Hg) from the electric power sector and is used extensively by EPA to support regulatory activities.

Among the factors that make IPM particularly well suited to model multi-emissions control programs are (1) its ability to capture complex interactions among the electric power, fuel, and environmental markets; (2) its detail-rich representation of emission control options encompassing a broad array of retrofit technologies along with emission reductions through fuel switching, changes in capacity mix and electricity dispatch strategies; (3) its capability to model a variety of environmental market mechanisms, such as emissions caps, allowances, trading, and banking; (4) and its ability to generate the detailed, location-specific emission data required for air quality modeling. IPM's ability to capture the dynamics of the allowance market and its provision of a wide range of emissions reduction options are particularly important for assessing the impact of multi-pollutant environmental policies for the power sector.

IPM is a single sector, linear programming model that captures the economic behavior of the power sector. By itself, IPM is limited in its ability to capture broader energy and environmental policy, such as an economy-wide cap and trade program. However, the model is often employed by EPA in conjunction with broader macroeconomic models to help provide deeper resolution of the power sector in the shorter term, which is an inherent weakness of broader econometric models which do not have detailed technology or power sector representation.

EPA's IPM Base Case 2006 (v3.0), v3.01, and Subsequent Updates:

In the fall of 2006, EPA released Base Case 2006 (v3.0) using IPM, which included extensive updates of IPM's assumptions, inputs, and capabilities. The model was again updated in the summer of 2007 for purposes of climate modeling (v3.01). In preparing these base cases, EPA obtained input from nationally recognized experts in fuels, technology, and power system operation. Power companies provided information on generating resources and emission controls. EPA also obtained input from Regional Planning Organizations, States, and their constituent organizations. Key updates included:

- Coal Supply and Transportation Assumptions
- Natural Gas Assumptions
- Federal and State Emission Regulations and Enforcement Actions
- Cost and Performance of Generating Technologies and Emission Controls

- Sulfur Dioxide (SO₂), Nitrogen Oxide (NO_x) emissions
- Power System Operating Characteristics and Structure
- Electric Generating Unit Inventory
- Modeling Time Horizon and Run Years (2010, 2015, 2020, 2025)
- Carbon capture and storage for potential (new) units
- Biomass co-firing capability for existing coal boilers
- Updated constraints on new nuclear and renewable capacity builds

For more recent climate analyses, EPA released Base Case 2009 using IPM. This version of the model provides additional modeling capabilities, includes several important updates, and incorporates key provisions of the Energy Independence and Security Act of 2007 (EISA). Among the notable features of this base case are:

- 1) Revised electricity demand¹
- 2) Updated power technology costs¹
- 3) Carbon capture and storage (CCS) for existing coal plants
- 4) Updated natural gas supply and price projection
- 5) Renewable portfolio standards and climate programs at the State level¹
- 6) Updated constraints on new nuclear, renewable, and coal with CCS capacity
- 7) Cost of carbon for new conventional coal plants¹

In response to the provisions of the American Recovery and Reinvestment Act (ARRA) of 2009, EPA released Base Case 2009 ARRA. Key updates include:

- 1) Revised electricity demand²
- 2) Updated power technology costs²
- 3) Updated biomass supply curve²
- 4) Updated state renewable portfolio standards and renewable energy provisions of ARRA²
- 5) CCS in reference case²
- 6) Power sector regulatory treatment (i.e., CAIR)
- 7) Run year mapping
- 8) Financial assumptions
- 9) State power sector rules and settlements
- 10) Updates to the National Electric Energy Data System (NEEDS)
- 11) Title IV SO₂ allowance bank estimate

The detailed assumptions for IPM v3.0, titled "Documentation for EPA Base Case 2006 (v3.0) Using the Integrated Planning Model" (November 2006), can be found at: <http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html#docs>.

The following document summarizes the key features and changes found in EPA's Base Case 2009 ARRA using IPM.

¹ Assumption derived from the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2009 Reference Case (March version), (<http://www.eia.doe.gov/oiaf/aeo/>).

² Assumption derived from the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2009 Reference Case (April version), (<http://www.eia.doe.gov/oiaf/aeo/>).

1a. Electricity Demand

The electric load assumptions in EPA Base Case 2009 ARRA are shown in the table below. These values were derived based on the electricity sales forecast in EIA's AEO 2009 (April release). The revised growth rate used in the reference case is just under 1%, compared to a growth rate of 1.5% in past IPM modeling applications.

Net Energy for Load in EPA Base Case 2009 ARRA (GWh)	
2012	4,095,979
2015	4,141,755
2020	4,351,981
2025	4,578,201

2. Potential (New) Unit Costs

All costs for potential units have been updated to reflect AEO 2009 ARRA levels and are generally 50% higher than pre-AEO 2009 modeling applications employed by EPA (v3.0). The tables below show the cost and performance characteristics of the modeled potential (new) build units.

Performance and Unit Cost Assumptions for Potential (New) Capacity from Conventional Technologies in EPA Base Case 2009 ARRA

	Advanced Combined Cycle	Advanced Combustion Turbine	Nuclear	Integrated Gasification Combined Cycle	Advanced Coal with Carbon Capture	Supercritical Pulverized Coal
Size (MW)	400	230	1350	550	380	600
First Year Available	2012	2012	2020	2015	2015	2015
Lead Time (Years)	3	2	6	4	4	4
Vintage #1 (years covered)	2012-2014	2012-2014		2012-2014	2012-2014	2012-2014
Vintage #2 (years covered)	2015-2019	2015-2019	2020-2035	2015-2019	2015-2019	2015-2019
Vintage #3 (years covered)	2020-2024	2020-2024		2020-2024	2020-2024	2020-2024
Vintage #4 (years covered)	2025-2031	2025-2031		2025-2031	2025-2031	2025-2031
Availability	87%	92%	90%	80%	80%	85%
Vintage #1						
Heat Rate (Btu/kWh)	6,752	9,289	-	-	-	-
Capital (2006\$/kW)	903	603	-	-	-	-
Fixed O&M (2006\$/kW/yr)	11.4	10.3	-	-	-	-
Variable O&M (2006\$/MWh)	1.95	3.09	-	-	-	-
Vintage #2						
Heat Rate (Btu/kWh)	6,752	9,289	10,434	8,765	10,781	9,200
Capital (2006\$/kW)	965	642	2995	2,414	3,503	2,113
Fixed O&M (2006\$/kW/yr)	11.4	10.3	87.7	37.7	44.9	26.8
Variable O&M (2006\$/MWh)	1.95	3.09	0.48	2.84	4.32	4.47
Vintage #3						
Heat Rate (Btu/kWh)	6,752	9,289	-	8,765	10,781	9,200
Capital (2006\$/kW)	895	593	-	2,233	3,082	1,974
Fixed O&M (2006\$/kW/yr)	11.4	10.3	-	37.7	44.9	26.8
Variable O&M (2006\$/MWh)	1.95	3.09	-	2.84	4.32	4.47
Vintage #4						
Heat Rate (Btu/kWh)	6,752	9,289	-	8,765	10,781	9,200
Capital (2006\$/kW)	789	515	-	1,972	2,689	1,772
Fixed O&M (2006\$/kW/yr)	11.4	10.3	-	37.7	44.9	26.8
Variable O&M (2006\$/MWh)	1.95	3.09	-	2.84	4.32	4.47
Vintage #5						
Heat Rate (Btu/kWh)	6,752	9,289	-	8,765	10,781	9,200
Capital (2006\$/kW)	693	446	-	1,739	2,342	1,591
Fixed O&M (2006\$/kW/yr)	11.4	10.3	-	37.7	44.9	26.8
Variable O&M (2006\$/MWh)	1.95	3.09	-	2.84	4.32	4.47

Note: Capital costs represent overnight capital costs

Performance and Unit Cost Assumptions for Potential (New) Renewable and Non-Conventional Technology Capacity in EPA Base Case 2009 ARRA

	Biomass Gasification Combined Cycle	Fuel Cells	Geothermal	Landfill Gas			Solar Photovoltaic	Solar Thermal	Wind
Size (MW)	80	10	50	30			5	100	50
First Year Available	2012	2012	2012	2012			2012	2012	2012
Lead Time (Years)	3	3	4	3			2	3	3
Vintage #1 (years covered)	2012-2019								
Vintage #2 (years covered)	2020-2035	2012-2035	2012-2035	2012-2035	2012-2035	2012-2035	2012-2035	2012-2035	2012-2035
Availability	80%	87%	87%	90%			90%	90%	95%
Generation Capability	Economic Dispatch	Economic Dispatch	Economic Dispatch	Economic Dispatch			Generation Profile	Generation Profile	Generation Profile
Vintage #1						LGVLo			
Heat Rate (Btu/kWh)	9,646	7,930	29,660 - 397,035	13,648	13,648	13,648	0	0	0
Capital (2006\$/kW)	3,559	4,983	1364 - 17,358	2,430	3,061	4,713	5,614	4,668	1,831-4,888
Fixed O&M (2006\$/kW/yr)	62.8	5.5	147-212	111.3	111.3	111.3	11.4	55.3	29.5
Variable O&M (2006\$/MWh)	6.5	46.7	0.00	0.01	0.01	0.01	0	0	0.00
Vintage #2									
Heat Rate (Btu/kWh)	9,646	-	-	-	-	-	-	-	-
Capital (2006\$/kW)	3,128	-	-	-	-	-	-	-	-
Fixed O&M (2006\$/kW/yr)	62.8	-	-	-	-	-	-	-	-
Variable O&M (2006\$/MWh)	6.5	-	-	-	-	-	-	-	-

Note: Capital costs represent overnight capital costs

EPA has also included a new CCS retrofit option for existing units larger than 400 MW in Base Case 2009 ARRA, available to the more efficient units in the coal fleet. This assumption is based upon a 2006 study commissioned by the National Energy Technology Laboratory (NETL) and reflects the cost of the capture technology as well as the energy penalty and subsequent capacity de-rating associated with capturing carbon from a power plant.³

Carbon Capture Retrofit Assumptions for Existing Coal-fired Units In EPA Base Case 2009 ARRA*

	Retrofit for Existing Coal Units of Capacity 400-775 MW	Retrofit for Existing Coal Units Larger than 775 MW
Capacity Penalty (%)	28.0%	28.0%
Heat Rate Penalty (%)	38.89%	39%
Availability (%)	85%	85%
Capital Cost (2006\$/kW)	1,200	974
FOM (2006\$/kW)	3.05	2.00
VOM (2006mills/kWh)	2.38	2.38
CO2 Removal (%)	90%	90%

3. Updated Biomass Supply

Biomass supply assumptions were adopted from AEO 2009.

4. Renewable portfolio standards and climate programs at the State level

A number of States have established renewable portfolio standards (RPS), and EPA has incorporated those requirements in Base Case 2009 ARRA. They are modeled based upon EIA's updated AEO 2009⁴ and result in considerably more renewable energy penetration in EPA's reference case 2009 ARRA using IPM. Although many States are considering RPS policies, EIA generally includes only policies that were firmly in place and reasonably fleshed out at the time AEO 2009 (April release) was finalized.

³ Carbon Dioxide Capture from Existing Coal-Fired Power Plants, DOE/NETL-401/110907, December 2006.

⁴ Energy Information Administration's Annual Energy Outlook 2009, Legislation and Regulations (http://www.eia.doe.gov/oiarf/aeo/leg_reg.html).

EPA has also updated the existing stock of renewables that is assumed to be in place at the beginning of the IPM modeling time horizon. To reflect the recent growth in renewables, particularly wind, the existing renewable generation capacity has been calibrated to EIA's AEO 2009 (April release) results for 2011.

A number of States have also adopted either State-level or regional climate programs. EPA includes those State and regional programs with sufficient specificity on emission targets, applicability, coverage, and policy mechanism to allow representation in IPM. The Northeast Regional Greenhouse Gas Initiative (RGGI) was the only regional program that met these criteria and was therefore included in Base Case 2009 ARRA modeling. State programs in Oregon and Washington State, which also have sufficiently specific requirements, were carried forward from v3.0.⁵

5. Carbon Capture and Storage Technology in the Reference Case

The AEO 2009 ARRA forecasts 2 GW of CCS capacity in the reference case for the year 2017. 1 GW is ascribed to the financial incentives for CCS included in the Emergency Economic Stabilization Act of 2008, and 1 GW is added to reflect ARRA 2009 appropriated funding to DOE for CCS deployment. In EPA Base Case 2009 ARRA, 2017 is included in the results mapped to the reported year 2015, and correspondingly, 2 GW of CCS are reported for 2015 in the reference case analysis.

6. Power sector regulatory treatment

For purposes of climate modeling using IPM 2009 ARRA, EPA included the Clean Air Interstate Rule (CAIR) in the baseline. The D.C. Circuit Court remanded CAIR without vacatur on December 23, 2008. The requirements under CAIR remain in place until EPA develops a replacement rule, a process that is currently under way. The Clean Air Visibility Rule (CAVR) and the Clean Air Mercury Rule (CAMR) were removed from the baseline. On February 8, 2008, the D.C. Circuit Court vacated EPA's rule removing power plants from the Clean Air Act list of sources of hazardous air pollutants and at the same time, the Court vacated the CAMR. In June 2005, EPA finalized guidelines for States to use in determining which facilities must install controls and the type of controls the facilities must use to satisfy Best Available Retrofit Technology (BART) requirements to address regional haze (also known as the CAVR). Because of uncertainty regarding the precise measures and requirements States will adopt, the specific CAVR power sector assumptions that were formerly modeled in IPM have been removed.

7. Run year mapping

Run Years and Analysis Year Mapping Used in the IPM Base Case 2009 ARRA

Run Year	Year Mapping
2012	2012 – 2013
2015	2014 – 2017
2020	2018 – 2022
2025	2023 – 2027

⁵ Documentation for EPA Base Case 2006 (v3.0), Section 3: Power System Operation Assumptions (<http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html>).

8. Financial assumptions

Capital Charge Rates and Real Discount Rates by Plant Type in IPM Base Case 2009 ARRA

Investment Technology	Capital Charge Rate	Discount Rate
Environmental Retrofits	11.4%	5.5%
Coal - Conventional Pulverized Coal	14.2%	7.8%
Coal - Integrated Gasification Combined Cycle	14.2%	7.8%
Coal - Integrated Gasification Combined Cycle with Carbon Capture	11.2%	5.5%
Advanced Combined Cycle	12.2%	6.1%
Advanced Combustion Turbine	12.9%	6.9%
Nuclear	10.8%	5.5%
Renewable Generation Technologies with Loan Guarantees	10.7%	4.6%
Renewable Generation Technologies without Loan Guarantees	12.2%	6.1%

9. State power sector rules and settlements

See Appendix.

10. Updates to the National Electric Energy Data System (NEEDS)

The National Electric Energy Data System or "NEEDS" database contains the generation unit records used to construct the "model" plants that represent existing and planned/committed units in EPA modeling applications of IPM. NEEDS includes basic geographic, operating, air emissions, and other data on these generating units. NEEDS was updated for IPM Base Case 2009 ARRA.

Data Sources for NEEDS V3.02 ARRA

Data Source¹	Data Source Documentation
DOE's Form EIA-860 (2005)	DOE's Form EIA-860 is an annual survey of utility power plants at the generator level. It contains data such as summer, winter and nameplate capacity, location (state and county), status, prime mover, primary energy source, in-service year, and a plant-level cogenerator flag.
DOE's Form EIA-767 (2005)	DOE's Form EIA-767 is an annual survey, "Steam-Electric Plant Operation and Design Report", that contains data for steam boilers such as fuel quantity and quality; boiler identification, location, status, and design information; and post-combustion NO _x control, FGD scrubber and particulate collector device information. Note that boilers in plants with less than 10 MW do not report all data elements. The relationship between boilers and generators is also provided. Note that boilers and generators are not necessarily in a one-to-one correspondence.
NERC Electricity Supply and Demand (ES&D) database (2006)	The NERC ES&D is released annually. It contains generator-level information such as summer, winter and nameplate capacity, state, NERC region and sub-region, status, primary fuel and on-line year.
EIA's Annual Energy Outlook (AEO 2008)	The Energy Information Administration (EIA) Annual Energy Outlook presents annually updated forecasts of energy supply, demand and prices covering a 20-25 year time horizon. The projections are based on results from EIA's National Energy Modeling System (NEMS). Information from AEO 2008, such as heat rates and renewable builds in response to state renewable portfolio standards (RPS) were used in NEEDS V3.02 ARRA.
Global Energy Decisions New Entrants database (August 2007)	Global Energy's New Entrants database has information on new power plant builds, rerates and retirements. This was used in NEEDS V3.02 ARRA for information on planned-committed units.

EPA's Emission Tracking System (ETS 2006)	The Emission Tracking System (ETS) database is updated quarterly and certified annually. It contains boiler-level information such as primary fuel, heat input, SO ₂ and NO _x controls, and SO ₂ , NO _x and CO ₂ emissions. NEEDS V3.02 ARRA used ETS data for developing emission rate and post-combustion control information.
Utility and RPO (Regional Planning Organizations) Comments	Comments from selected U.S. utilities and RPOs regarding the population in NEEDS as well as unit characteristics were used in NEEDS V3.02 ARRA.

¹Indicated under "Data Source" are the primary issue dates of the indicated data sources that were used. Other vintages of these data sources were also used in instances where data were not available for the indicated issue date or where there were methodological reasons for using other vintages of the data.

Rules Used in Populating NEEDS V3.02 ARRA

Scope

Geographic	Excluded units in Alaska or Hawaii
Capacity	Excluded units with reported nameplate, summer and winter capacity of zero
Status	Excluded units on long-term scheduled maintenance or units with forced outages for greater than three months or retired (i.e. units with status codes "OS" or "RE" in EIA Forms) Status of boiler(s) and associated generator(s) were taken into account for determining operation status
Planned or Future Units	Included planned units that had broken ground or secured financing and were expected to be online by the end of 2011
Firm/Non-firm Electric Sales	Excluded non-utility onsite generators that do not produce electricity for sale to the grid. Excluded all mobile and distributed generators

Summary Population (through 2005) in NEEDS V3.02 ARRA

Plant Type	Number of Units	Capacity (MW)
Biomass	126	2,124
Coal Steam	1,247	306,062
Combined Cycle	1,493	172,567
Combustion Turbine	5,248	131,366
Fossil Waste	19	581
Geothermal	201	2,194
Hydro	3,724	77,414
IGCC	4	529
Landfill Gas	572	892
Municipal Solid Waste	172	2,054

Non-Fossil Waste	48	530
Nuclear	104	101,099
O/G Steam	698	113,618
Pumped Storage	150	20,864
Solar	18	411
Tires	3	44
Wind	275	8,711
Total	14,102	941,060

Hierarchy of Data Sources for Capacity in NEEDS V3.02 ARRA

Sources Presented in Hierarchy

Capacity from Utility/Regional Planning
Organization(RPO) Comments
2005 EIA 860 Summer Capacity
NERC ES&D 2006 Summer Capacity
2005 EIA 860 Winter Capacity
NERC ES&D 2006 Winter Capacity
2005 EIA 860 Nameplate Capacity

Notes:

1. If a unit's capacity was shown as zero, it was not included in NEEDS V3.02 ARRA.

Capacity-Parsing Algorithm for Steam Units in NEEDS V3.02 ARRA

Type of Boiler-Generator Link				
For Boiler B ₁ to B _N linked to Generators G ₁ to G _N	One-to-One	One-to-Many	Many-to-One	Many-to-Many
		$MW_{Bi} = MW_{Gi}$	$MW_{Bi} = \sum_i MW_{Gi}$	$MW_{Bi} = (MF_{Bi} / \sum_i MF_{Bi}) * MW_{Gi}$

Data Sources for Unit Configuration in NEEDS V3.02 ARRA

Unit Component	Primary Data Source	Secondary Data Source	Tertiary Data Source	Other Sources	Default
Firing Type	Utility/RPO Comments	2005 EIA 767	-	-	-
Bottom Type	Utility/RPO Comments	2005 EIA 767	-	-	Dry
SO ₂ Pollution Control	NSR Settlement or Utility/RPO Comments	EPA's Emission Tracking System (ETS) - 2006	2005 EIA 767	See Note ₁	No Control
NO _x Pollution Control	NSR Settlement or Utility/RPO Comments	EPA's Emission Tracking System (ETS) - 2006	2005 EIA 767	See Note ₁	No Control
Particulate Matter Control	NSR Settlement or Utility/RPO Comments	EPA's Emission Tracking System (ETS) - 2006	2005 EIA 767	1999 Hg ICR	-

In addition to the primary, secondary and tertiary data sources listed here, the web sites of generating unit owners and operators were also consulted.

11. Title IV SO₂ allowance bank estimate

The Title IV SO₂ bank going into 2012 was assumed to be 1.6 million allowances.

**APPENDIX:
State Rules/ Requirements
and NSR Settlements**

State Rules and Requirements

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
California	CA Reclaim Market	NO _x	9.68 MTons annual cap for any source with actual emissions of 4 tons or more in 1990 and thereafter	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	4.292 MTons annual cap for any source with actual emissions of 4 tons or more in 1990 and thereafter		
Delaware	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 greater than 25 MW	2009	
		SO ₂	0.26 lbs/MMBtu annual rate limit for coal and residual-oil fired units greater than 25 MW		
Georgia	Multipollutant 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, Part 225, Subpart B: Control of Hg Emissions from Coal Fired Electric Generation Units	NO _x	0.11 lbs/MMBtu annual rate limit and ozone season rate limit for all Dynergy and Ameren coal steam units greater than 25 MW	2012	
		SO ₂	0.33 lbs/MMBtu annual rate limit for all Dynergy and Ameren coal steam units greater than 25 MW	2013	
		Hg	90% Hg removal (or emission rate of 0.08 lbs/GWh) for all Ameren coal units greater than 25 MW and 90% Hg removal (or 0.08 lbs/GWh) for all Dynergy coal units greater than 25 MW	2015	
	Title 35 Part 225; Subpart F: Combined Pollutant Standards	NO _x	0.11 lbs/MMBtu annual rate limit and during the ozone season for all Midwest Gen coal steam units	2012	Will County unit has a unique restriction of 90% (or 0.08 lbs/GWh) starting in 2016
		SO ₂	0.44 lbs/MMBtu annual rate limit in 2013, decreasing annually to 0.11 lbs/MMBtu in 2019 for all Midwest Gen coal steam units	2013	
		Hg	90% Hg removal (or emission rate of 0.08 lbs/GWh) annually for all Midwest Gen coal steam units	2015	
Maine	Chapter 145 NO _x Control Program	NO _x	0.15 lbs/MMBtu annual rate limit for all fossil fuel units greater than 25 MW built before 1995 with a heat input capacity greater than 750 MMBtu/hr and 0.20 lbs/MMBtu annually for all fossil fuel fired indirect heat exchangers, primary boilers, and resource recovery units with heat input capacity greater than 250 MMBtu/hr	2005	
	Statue 585-B Title 38, Chapter 4: Protection and Improvement of Air	Hg	Cap of 100 lbs of Hg annually for any facility including EGUs gradually lowering to 25 lbs in 2010	2005	
Minnesota	Minnesota Hg Emission Reduction Act	Hg	90% removal of Hg content of fuel annually for all coal units greater than 250 MW	2008	
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, 5, & 6	2013	Scrubbers must also be installed at the Merrimack Station units
	ENV-A2900 Multiple pollutant annual budget trading and banking program	CO ₂	REMOVED: CO ₂ annual cap of 5,426 Mtons for six specific existing steam units owned by PSNH	2007	This constraint was removed as the cap was no longer in effect given RGGI.

State Rules and Requirements

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
Texas	Senate Bill 7 Chapter 101	SO ₂	273.95 MTons cap of SO ₂ for all grandfathered units built before 1971 in East Texas Region	2003	
		NO _x	Annual cap for all grandfathered units built before 1971 in MTons: 84.48 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 Coal fired units: 0.165 Stationary gas turbines: 0.14	2007	
			Dallas/Fort Worth Area annual rate limit for utility boilers, auxiliary steam boilers, stationary gas turbines, and duct burners used in an electric power generating system except for CT and CC units online after 1992: 0.033 lbs/MMBtu or 0.50 lbs/MWh output or 0.0033 lbs/MMBtu on system wide heat input weighted average for large utility systems 0.06 lbs/MMBtu for small utility systems		
Housont/Galveston region annual Cap and Trade (MECT) for all fossil units: 8.46 Mtons					
			Beaumont-Port Arthur region annual rate limits for utility boilers, auxiliary steam boilers, stationary gas turbines, and duct burners used in an electric power generating system: 0.10 lbs/MMBtu		
Wisconsin	NR 428 Wisconsin Administration Code	NO _x	Annual rate limits in lbs/MMBtu for coal fired boilers greater than 1,000 MMBtu/hr : Wall fired, tangential fired, cyclone fired, and fluidized bed: 2009: 0.15, 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: 2009: 0.20; 2013 onwards: 0.17 in 2013 Tangential fired: 2009 onwards: 0.15 Cyclone fired: 2009: 0.20; 2013 onwards: 0.15 Fluidized bed: 2009: 0.15; 2013 onwards: 0.10 Arch fired: 2009 onwards: 0.18		
			Annual rate limits for CTs in lbs/MMBtu: Natural gas CTs greater than 50 MW: 0.11 Distillate oil CTs greater than 50 MW: 0.28 Biologically derived fuel CTs greater than 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 greater than 25 MW: 0.04 Distillate oil CCs greater than 25 MW: 0.18 Biologically derived fuel CCs greater than 25 MWs: 0.15 Natural gas CCs between 10 and 24 MW: 0.19		
	WI Hg rule	Hg	75% reduction of Hg emissions to coal fired units belonging to Alliant Energy, WE Energies, Wisconsin Public Service and Dairyland Power Cooperative	2010	

New Source Review Settlements

Company and Plant	State	Unit	SETTLEMENT ACTIONS										Allowance Retirement	Allowance Restrictions		Notes		
			Retire/Repower		SO ₂ Control			NO _x Control			PM or Mercury Control			Restriction	Effective Date			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate					Effective Date	
Kentucky Utilities Company																		
EW Brown Generating Station	Kentucky	Unit 3			Install FGD	97% or 0.100	12/31/10	Install and continuously operate SCR by 12/31/2012, continuously operate low NO _x boiler and OFA.	0.07	12/31/12	Continuously operate ESP	0.03	12/31/10	KU must surrender 53,000 SO ₂ allowances of 2008 or earlier vintage by March 1, 2009. All surplus NO _x allowances must be surrendered through 2020.	SO ₂ and NO _x allowances may not be used for compliance, and emissions decreases for purposes of complying with the Consent Decree do not earn credits.		Annual SO ₂ cap is 31,998 tons through 2010, then 2,300 tons each year thereafter. Annual NO _x cap is 4,072 tons.	
American Electric Power																		
Eastern System-Wide						Annual Cap (tons)	Year		Annual Cap (tons)	Year				NO _x and SO ₂ allowances may not be used to comply with any of the limits imposed by the Consent Decree. The Consent Decree includes a formula for calculating excess NO _x allowances relative to the CAIR Allocations, and restricts the use of some. See par. 74-79 for details. Reducing emissions below the Eastern System-Wide Annual Tonnage Limitations for NO _x and SO ₂ earns surplus allowances.				
						450,000	2010		96,000	2009								
						450,000	2011		92,500	2010								
						420,000	2012		92,500	2011								
						350,000	2013		85,000	2012								
						340,000	2014		85,000	2013								
						275,000	2015		85,000	2014								
						260,000	2016		75,000	2015								
						235,000	2017		72,000	2016 and thereafter								
						184,000	2018											
					174,000	2019 and thereafter												
At least 600MW from various units	West Virginia	Sporn 1 - 4	Retire, retrofit, or re-power	12/31/18														
	Virginia	Clinch River 1 - 3																
	Indiana	Tanners Creek 1 - 3																
Amos	West Virginia	Unit 1			Install and continuously operate FGD		12/31/09	Install and continuously operate SCR		01/01/08								
		Unit 2		12/31/10			01/01/09											
		Unit 3		12/31/09			01/01/08											
Big Sandy	Kentucky	Unit 1			Burn only coal with no more than 1.75 lb/MMBtu annual average		Date of entry	Continuously operate low NO _x burners		Date of entry								
		Unit 2		12/31/15			01/01/09											
Cardinal	Ohio	Units 1, 2			Install and continuously operate FGD		12/31/08	Install and continuously operate SCR		01/01/09	Continuously operate ESP	0.03	12/31/09					
		Unit 3		12/31/12														
Clinch River	Virginia	Units 1 - 3				Annual Cap (tons)	Year	Continuously operate low NO _x burners		Date of entry								
						21,700	2010											
						21,700	2011											
						21,700	2012											
						21,700	2013											
						21,700	2014											
Conesville	Ohio	Units 1, 2	Retire, retrofit, or re-power	Date of entry 12/31/12														
		Unit 3																
		Unit 4			Install and continuously operate FGD		12/31/10	Install and continuously operate SCR		12/31/10								
Gavin	Ohio	Units 5, 6			Upgrade existing FGD	95%	12/31/09	Continuously operate low NO _x		Date of entry								
		Units 1, 2			Install and continuously operate FGD		Date of entry	Install and continuously operate SCR		01/01/09								
Glen Lyn	Virginia	Units 5, 6			Burn only coal with no more than 1.75 lb/MMBtu annual average		Date of entry	Continuously operate low NO _x burners		Date of entry								
Kammer	West Virginia	Units 1 - 3				Plant-wide annual cap: 35,000	01/01/12	Continuously operate over-fire air		Date of entry								
Kanawha River	West Virginia	Units 1, 2			Burn only coal with no more than 1.75 lb/MMBtu annual average		Date of entry	Continuously operate low NO _x burners		Date of entry								
Mitchell	West Virginia	Units 1, 2			Install and continuously operate FGD		12/31/07	Install and continuously operate SCR		01/01/09								
Mountaineer	West Virginia	Unit 1			Install and continuously operate FGD		12/31/07	Install and continuously operate SCR		01/01/08								
Muskingum River	Ohio	Units 1 - 4	Retire, retrofit, or re-power	12/31/15														
		Unit 5			Install and continuously operate FGD		12/31/15	Install and continuously operate SCR		01/01/08	Continuously operate ESP	0.03	12/31/02					
Picway	Ohio	Unit 9						Continuously operate low NO _x burners		Date of entry								
Rockport	Indiana	Unit 1			Install and continuously operate FGD		12/31/17	Install and continuously operate SCR		12/31/17								
		Unit 2		12/31/19			12/31/19											
Sporn	West Virginia	Unit 5	Retire, retrofit, or re-power	12/31/13														
Tanners Creek	Indiana	Units 1 - 3			Burn only coal with no more than 1.2 lb/MMBtu annual average		Date of entry	Continuously operate low NO _x burners		Date of entry								
		Unit 4				Burn only coal with no more than 1.2% sulfur content annual average						Continuously operate over-fire air						

New Source Review Settlements

Company and Plant	State	Unit	SETTLEMENT ACTIONS										Allowance Retirement	Allowance Restrictions		Notes		
			Retire/Repower		SO ₂ Control			NO _x Control			PM or Mercury Control			Restriction	Effective Date			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate					Effective Date	
East Kentucky Power Cooperative Inc.																		
Dale Plant	Kentucky	Units 1, 2						Install and continuously operate low NO _x burners by 10/31/2007	0.46	01/01/08						EKPC must surrender 1,000 NO _x allowances immediately under the ARP, and 3,107 under the NO _x SIP Call. EKPC must also surrender 15,311 SO ₂ allowances.		Date of entry
		System-wide			System-wide 12-month rolling tonnage limits apply	12-month rolling limit (tons)	Start of 12-month cycle	All units must operate low NO _x boilers	12-month rolling limit (tons)	Start of 12-month cycle	PM control devices must be operated continuously system-wide.	0.03	1 year from entry date		All surplus SO ₂ allowances must be surrendered each year, beginning in 2008.	SO ₂ and NO _x allowances may not be used to comply with the Consent Decree. NO _x allowances that would become available as a result of compliance with the Consent Decree		By 12/31/2009, EKPC shall choose whether to: 1) install and continuously operate NO _x controls at Cooper 2 by 12/31/2012 and SO ₂ controls by 6/30/2012 or 2) retire Dale 3 and Dale 4 by 12/31/2012.
						57,000	10/01/08		11,500	01/01/08								
						40,000	07/01/11		8,500	01/01/13								
						28,000	01/01/13		8,000	01/01/15								
Spurlock	Kentucky	Unit 1			Install and continuously operate FGD	95% or 0.1	6/30/2011	Continuously operate SCR	0.12 for Unit 1 until 01/01/2013, at which point the unit limit drops to 0.1. Prior to 01/01/2013, the combined average when both units are operating must be no more than 0.1	60 days after entry								
		Unit 2			Install and continuously operate FGD by 10/1/2008	95% or 0.1	1/1/2009	Continuously operate SCR and OFA	0.1 for Unit 2, 0.1 combined average when both units are operating									
Dale Plant	Kentucky	Units 3, 4	EKPC may choose to retire Dale 3 and 4 in lieu of installing controls in Cooper 2	12/31/2012														
Cooper	Kentucky	Unit 2			If EKPC opts to install controls rather than retiring Dale, it must install and continuously operate FGD or equiv. technology	95% or 0.10	12/31/11	If EKPC elects to install controls, it must continuously operate SCR or install equiv. technology	0.08 (or 90% if non-SCR technology is used)	12/31/12								
Nevada Power Company																		
Clark Generating Station	Nevada	Unit 5						Increase water injection immediately, then install and operate ultra-low NO _x burners (ULNBs) or equivalent technology. In 2009, Units 5 and 8 may not emit more than 180 tons combined										
		Units 6, 7	Units may only fire natural gas						5ppm 1-hour average	12/31/08 (ULNB installation), 01/30/09 (1-hour average)					Allowances may not be used to comply with the Consent Decree, and no allowances made available due to compliance with the Consent Decree may be traded or sold.			Beginning 1/1/2010, combined NO _x emissions from Units 5,6,7, and 8 must be no more than 360 tons per year.
		Unit 8								12/31/09 (ULNB installation), 01/30/10 (1-hour average)								
										12/31/08 (ULNB installation), 01/30/09 (1-hour average)								
PSEG FOSSIL																		
Kearny	New Jersey	Units 7, 8	Retire units	01/01/07														
Hudson	New Jersey	Unit 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/10	Install SCR (or approved tech) and continually operate	0.1	12/31/10	Install Baghouse (or approved technology)	0.015	12/31/10					
						Annual Cap (tons)	Year		Annual Cap (tons)	Year								
						5,547	2007		3,486	2007								
						5,270	2008		3,486	2008								
						5,270	2009		3,486	2009								
						5,270	2010		3,486	2010								
Mercer	New Jersey	Units 1, 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/10	Install SCR (or approved tech) and continually operate	0.1	01/01/07	Install Baghouse (or approved technology)	0.015	12/31/10		8,568 SO ₂ Allowances not already allocated to or generated by the units listed here. Kearny			

Notes:
 1) This summary table describes incremental changes in New Source Review settlement actions as they are represented in EPA Base Case 3.0 to IPM Base Case 2009 ARRA. The settlement actions are simplified for representation in the model. This table is not intended to be a comprehensive description of all elements of the actual settlement agreements.