3. Power System Operation Assumptions

This section describes the assumptions pertaining to the North American electric power system as represented in EPA Base Case v.5.13.

3.1 Model Regions

EPA Base Case v.5.13 models the US power sector in the contiguous 48 states and the District of Columbia and the Canadian power sector in the 10 provinces (with Newfoundland and Labrador represented as two regions on the electricity network even though politically they constitute a single province[6]) as an integrated network.

There are 64 IPM model regions covering the US 48 states and District of Columbia. The IPM model regions are approximately consistent with the configuration of the NERC assessment regions in the NERC Long-Term Reliability Assessments. These IPM model regions reflect the administrative structure of regional transmission organizations (RTOs) and independent system operators (ISOs). Further disaggregation of the NERC assessment regions and RTOs allows a more accurate characterization of the operation of the US power markets by providing the ability to represent transmission bottlenecks across RTOs and ISOs, as well as key transmission limits within them.

The IPM regions also provide disaggregation of the regions of the National Energy Modeling System (NEMS) to provide for a more accurate correspondence with the demand projections of the Annual Energy Outlook (AEO). Notable disaggregations are further described below:

NERC assessment regions MISO and PJM cover the areas of the corresponding RTOs and are designed to better represent transmission limits and dispatch in each area. In IPM, the MISO area is disaggregated into 9 IPM regions and the PJM assessment area is disaggregated into 9 IPM regions, where the IPM regions are selected to represent planning areas within each RTO and/or areas with internal transmission limits.

New York is now disaggregated into 7 IPM regions, to better represent flows around New York City and Long Island, and to better represent flows across New York state from Canada and other US regions.

The NERC assessment region SERC is divided into North, South, West and Southeast areas; IPM further disaggregates the North and West areas to better represent transmission between areas, including disaggregating SERC-West into four IPM regions to reflect transmission constraints in Southern Louisiana.

IPM retains the NERC assessment areas within the overall WECC regions, and further disaggregates these areas using sub-regions from the WECC Power Supply Assessment.

The 11 Canadian model regions are defined strictly along provincial political boundaries.

Figure 3-1 contains a map showing all the EPA Base Case 5.13 model regions. Using these shares of each NEMS region net energy for load that falls in each IPM region, calculate the total net energy for load for each IPM region from the NEMS regional load in AEO 2013.

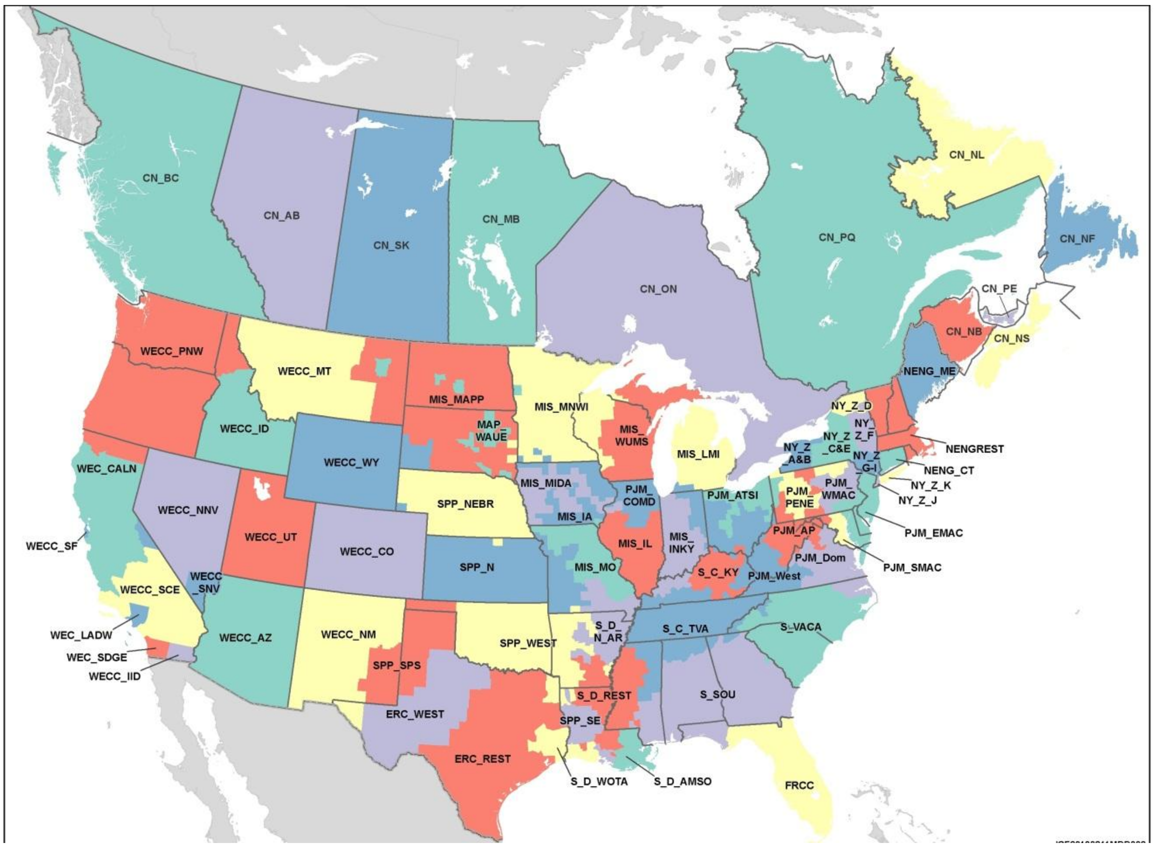
Table 3-1 defines the abbreviated region names appearing on the map and gives a crosswalk between the IPM model regions, the NERC assessment regions, and regions used in the Energy Information Administration's (EIA's) National Energy Model System (NEMS) which is the basis for EIA's Annual Energy Outlook (AEO) reports.

[6] This results in a total of 11 Canadian model regions being represented in EPA Base Case v.5.13.

3.2 Electric Load Modeling

Net energy for load and net internal demand are inputs to IPM that together are used to represent the grid-demand for electricity. Net energy for load is the projected annual electric grid-demand, prior to accounting for intra-regional transmission and distribution losses. Net internal demand (peak demand) is the maximum hourly demand within a given year after removing interruptible demand. Table 3-2 shows the electricity demand assumptions (expressed as net energy for load) used in EPA Base Case v.5.13. It is based on the net energy for load in AEO 2013.[7]

Figure 3-1 EPA Base Case v.5.13 Model Regions



For purposes of documentation, Table 3-2 presents the national net energy for load. However, EPA Base Case v.5.13 models regional breakdowns of net energy for load in each of the 64 IPM US regions in the following steps:

- The net energy for load in each of the 22 NEMS electricity regions is taken from the NEMS reference case.
- NERC balancing areas are assigned to both IPM regions and NEMS regions to determine the share of the NEMS net energy for load in each NEMS regions that falls into each IPM region. These shares are calculated in the following steps.
  - Map the NERC Balancing Authorities/ Planning Areas in the US to the 64 IPM regions.

[7] The electricity demand in EPA Base Case v.5.13 for the U.S. lower 48 states and the District of Columbia is obtained for each IPM model region by disaggregating the "Total Net Energy for Load" projected for the corresponding NEMS Electric Market Module region as reported in the Electricity and Renewable Fuel Tables 73-120" at http://www.eia.gov/forecasts/aeo/tables_ref.cfm.

- Map the Balancing Authorities/ Planning Areas in the US to the 22 NEMS regions.
- Using the 2007 data from FERC Form 714 on net energy for load in each of the balancing areas, calculate the proportional share of each of the net energy for load in 22 NEMS regions that falls in each of the 64 IPM Regions.

- Using these shares of each NEMS region net energy for load that falls in each IPM region, calculate the total net energy for load for each IPM region from the NEMS regional load in AEO 2013.

Table 3-1 Mapping of NERC Regions and NEMS Regions with EPA Base Case v.5.13 Model Regions

NERC Assessment Region	AEO 2013 NEMS Region	Model Region	Model Region Description
ERCOT[a]	ERCT (1)	ERC_FRNT	ERCOT_Tenaska Frontier Generating Station
		ERC_GWAY	ERCOT_Tenaska Gateway Generating Station
		ERC_REST	ERCOT_Rest
		ERC_WEST	ERCOT_West
FRCC	FRCC (2)	FRCC	FRCC
MAPP	MROW (4)	MAP_WAUE	MAPP_WAUE
		MIS_MAPP	MISO_MT, SD, ND
MISO	MROE (3), RFCW (11)	MIS_WUMS	MISO_Wisconsin- Upper Michigan (WUMS)
	MROW (4)	MIS_IA	MISO_Iowa
		MIS_MIDA	MISO_Iowa-MidAmerican
		MIS_MNWI	MISO_Minnesota and Western Wisconsin
	RFCM (10)	MIS_LMI	MISO_Lower Michigan
	RFCW (11), SRCE (15)	MIS_INKY	MISO_Indiana (including parts of Kentucky)
	SRGW (13)	MIS_IL	MISO_Illinois
		MIS_MO	MISO_Missouri
ISO-NE	NEWE (5)	NENG_CT	ISONE_Connecticut
		NENG_ME	ISONE_Maine
		NENGREST	ISONE_MA, VT, NH, RI (Rest of ISO New England)
NYISO	NYCW (6)	NY_Z_J	NY_Zone J (NYC)
	NYLI (7)	NY_Z_K	NY_Zone K (LI)
	NYUP (8)	NY_Z_A&B	NY_Zones A&B
		NY_Z_C&E	NY_Zone C&E
		NY_Z_D	NY_Zones D
		NY_Z_F	NY_Zone F (Capital)
	NYUP (8), NYCW (6)	NY_Z_G-I	NY_Zone G-I (Downstate NY)
PJM	RFCE (9)	PJM_EMAC	PJM_EMAAC
		PJM_PENE	PJM_PENELEC
		PJM_SMAC	PJM_SWMAAC
		PJM_WMAC	PJM_Western MAAC
	RFCW (11)	PJM_AP	PJM_AP
		PJM_ATSI	PJM_ATSI
		PJM_COMD	PJM_ComEd
		PJM_West	PJM West
	SRVC (16)	PJM_Dom	PJM_Dominion
SERC-E	SRVC (16)	S_VACA	SERC_VACAR
SERC-N	SRCE (15)	S_C_KY	SERC_Central_Kentucky

NERC Assessment Region	AEO 2013 NEMS Region	Model Region	Model Region Description
		S_C_TVA	SERC_Central_TVA
SERC-SE	SRSE (14)	S_SOU	SERC_Southeastern
SERC-W	SRDA (12)	S_D_AMSO	SERC_Delta_Amite South (including DSG)
		S_D_WOTA	SERC_Delta_WOTAB (including Western)
		S_D_REST	SERC_Delta_Rest of Delta (Central Arkansas)
	SRDA (12), SRCE (15)	S_D_N_AR	SERC_Delta_Northern Arkansas (including AECI)
SPP[b]	MROW (4)	SPP_NEBR	SPP Nebraska
	SPNO (17), SRGW (13)	SPP_N	SPP North- (Kansas, Missouri)
	SPSO (18)	SPP_KIAM	SPP_Kiamichi Energy Facility
		SPP_SE	SPP Southeast (Louisiana)
		SPP_SPS	SPP SPS (Texas Panhandle)
	SPSO (18), SRDA (12)	SPP_WEST	SPP West (Oklahoma, Arkansas, Louisiana)
Basin (BASN)	NWPP (21)	WECC_ID	WECC_Idaho
		WECC_NNV	WECC_Northern Nevada
		WECC_UT	WECC_Utah
Northern California (CALN)	CAMX (20)	WEC_CALN	WECC_Northern California (including SMUD)
		WECC_SF	WECC_San Francisco
Southern California (CALS)	AZNM (19)	WECC_IID	WECC_Imperial Irrigation District (IID)
	CAMX (20)	WEC_LADW	WECC_LADWP
		WEC_SDGE	WECC_San Diego Gas and Electric
		WECC_SCE	WECC_Southern California Edison
Northwest (NORW)	NWPP (21)	WECC_MT	WECC_Montana
		WECC_PNW	WECC_Pacific Northwest
Rockies (Rock)	NWPP (21), RMPA (22)	WECC_WY	WECC_Wyoming
	RMPA (22)	WECC_CO	WECC_Colorado
Desert Southwest (DSW)	AZNM (19)	WECC_AZ	WECC_Arizona
		WECC_NM	WECC_New Mexico
		WECC_SNV	WECC_Southern Nevada
Canada		CN_AB	Alberta
		CN_BC	British Columbia
		CN_MB	Manitoba
		CN_NB	New Brunswick
		CN_NF	Newfoundland
		CN_NL	Labrador
		CN_NS	Nova Scotia
		CN_ON	Ontario
		CN_PE	Prince Edward Island
		CN_PQ	Quebec
		CN_SK	Saskatchewan

[a] ERCOT_Tenaska Frontier Generating Station (ERC_FRNT) and ERCOT_Tenaska Gateway Generating Station (ERC_GWAY) regions in ERCOT are switching regions without any internal demand created to capture the ability to sell power to multiple power markets.

[b] SPP_Kiamichi Energy Facility [SPP_KIAM] region in SPP is a switching region without any internal demand created to capture the ability to sell power to multiple power markets.

Table 3-2 Electric Load Assumptions in EPA Base Case v.5.13

Year	Net Energy for Load (Billions of KWh)
2016	4,049
2018	4,135
2020	4,215
2025	4,390
2030	4,535
2040	4,887
2050	5,271

Notes:
This data is an aggregation of the model-region-specific net energy loads used in the EPA Base Case v.5.13.

3.2.1 Demand Elasticity

EPA Base Case v.5.13 has the capability to consider endogenously the relationship of the price of power to electricity demand. However, this capability is typically only exercised for sensitivity analyses where different price elasticities of demand are specified for purposes of comparative analysis. The default base case assumption is that the electricity demand shown in Table 3-2, which was originally derived from EIA modeling that did consider price elasticity of demand, must be met as IPM solves for least-cost electricity supply. This approach maintains a consistent expectation of future load between the EPA Base Case and the corresponding EIA Annual Energy Outlook reference case (e.g., between EPA Base Case v5.13 and the AEO2013 reference case).

3.2.2 Net Internal Demand (Peak Demand)

EPA Base Case v5.13 has separate regional winter and summer peak demand values, as derived from each region's seasonal load duration curve (found in Attachment 2-1). Peak projections were estimated based on AEO 2013 load factors and the estimated energy demand projections shown in Table 3-2. Table 3-3 illustrates the national sum of each region's winter and summer peak demand. Because each region's seasonal peak demand need not occur at the same time, the national peak demand is defined as non-coincidental (i.e., national peak demand is a summation of each region's peak demand at whatever point in time that region's peak occurs across the given time period).

Table 3-3 National Non-Coincidental Net Internal Demand

	Peak Demand (GW)	
Year	Winter	Summer
2016	657	746
2018	670	761
2020	686	780
2025	725	826
2030	763	873
2040	845	972
2050	916	1,053

Notes:
This data is an aggregation of the model-region-specific peak demand loads used in the EPA Base Case v.5.13.

3.2.3 Regional Load Shapes

As of 2013, EPA has adopted year 2011 as the meteorological year in its air quality modeling. In order for EPA Base Case v.5.13 to be consistent, the year 2011 was selected as the "normal weather year"[8] for all IPM regions. The proximity of the 2011 cumulative annual heating degree days (HDDs) and cooling degree days (CDDs) to the long-term average cumulative annual HHDs and CDDs over the period 1981 to 2010 was estimated and found to be reasonably close. The 2011 chronological hourly load data were assembled by aggregating individual utility load curves taken from Federal Energy Regulatory Commission Form 714 data and individual ISOs and RTOs.

3.3 Transmission

The United States and Canada can be broken down into several power markets that are interconnected by a transmission grid. As discussed earlier, EPA Base Case 5.13 characterizes the U.S. lower 48 states, the District of Columbia, and Canada into 75 different model regions by means of 61 power market regions and 3 power switching regions[9] in the U.S. and 11 power market regions in Canada. EPA Base Case 5.13 includes explicit assumptions regarding the transmission grid connecting these modeled power markets. This section details the assumptions about the transfer capabilities, wheeling costs and inter-regional transmission used in EPA Base Case 5.13.

3.3.1 Inter-regional Transmission Capability

Table 3-4[10] shows the firm and non-firm Total Transfer Capabilities (TTCs) between model regions. TTC is a metric that represents the capability of the power system to import or export power reliably from one region to another. The purpose of TTC analysis is to identify the sub-markets created by key commercially significant constraints. Firm TTCs, also called Capacity TTCs, specify the maximum power that can be transferred reliably, even after the contingency loss of a single transmission system element such as a transmission line or a transformer (a condition referred to as N-1, or "N minus one"). Firm TTCs provide a high level of reliability and are therefore used for capacity transfers. Non-firm TTCs, also called Energy TTCs, represent the maximum power that can be transferred reliably when all facilities are under normal operation (a condition referred to as N-0, or "N minus zero"). They specify the sum of the maximum firm transfer capability between sub-regions and incremental curtailable non-firm transfer capability. Non-firm TTCs are used for energy transfers since they provide a lower level of reliability than Firm TTCs, and transactions using Non-firm TTCs can be curtailed under emergency or contingency conditions.

Table 3-4 Annual Transmission Capabilities of U.S. Model Regions in EPA Base Case v.5.13

From	To	2016		2018		Transmission Tariff (2011 mills/kWh)
		Capacity TTC (MW)	Energy TTC (MW)	Incremental Capacity TTC (MW)	Incremental Energy TTC (MW)	
ERC_FRNT	ERC_REST	860	860			0
	SPP_WEST	860	860			6

[8] The term "normal weather year" refers to a representative year whose weather is closest to the long-term (e.g., 35 year) average weather. The selection of a "normal weather year" can be made, for example, by comparing the cumulative annual heating degree days (HDDs) and cooling degree days (CDDs) in a candidate year to the long-term average. For any individual day, heating degree days indicate how far the average temperature fell below 65 degrees F; cooling degree days indicate how far the temperature averaged above 65 degrees F. Cumulative annual heating and cooling degree days are the sum of all the HDDs and CDDs, respectively, in a given year.

[9] Power switching regions are regions with no market load that represent individual generating facilities specifically configured so they can sell directly into either ERCOT or SPP: these plants are implemented in IPM as regions with transmission links only to ERCOT and to SPP.

[10] In the column headers in Table 3-4 the term "Energy TTC (MW)" is equivalent to non-firm TTCs and the term "Capacity TTC (MW)" is equivalent to firm TTCs.

From	To	2016 Capacity TTC (MW)	2016 Energy TTC (MW)	2018 Incremental Capacity TTC (MW)	2018 Incremental Energy TTC (MW)	Transmission Tariff (2011 mills/kWh)
ERC_GWAY	ERC_REST	845	845			0
	SPP_WEST	845	845			6
ERC_REST	ERC_WEST	5,529	5,529			0
	SPP_WEST	600	600			6
ERC_WEST	ERC_REST	10,555	10,555			0
	SPP_WEST	220	220			6
FRCC	S_SOU	3,600	3,600			8
MAP_WAUE	CN_SK	0	100			8
	MIS_IA	0	100			6
	MIS_MAPP	1,000	1,500			0
	MIS_MIDA	600	1,000			6
	MIS_MNWI	2,000	3,000			6
	SPP_NEBR	700	1,000			6
MIS_IA	MAP_WAUE	0	100			6
	MIS_IL	0	100			0
	MIS_MIDA	900	2,000			0
	MIS_MNWI	1,195	2,000			0
	MIS_MO	223	711			0
	PJM_COMD	0	600			3
	S_D_N_AR	0	100			1
MIS_IL	MIS_IA	0	100			0
	MIS_INKY	240	1,195			0
	MIS_MIDA	0	100			0
	MIS_MO	3,400	4,500			0
	PJM_COMD	2,500	3,000			3
	PJM_West	0	1,300			3
	S_C_TVA	1,200	1,500			6
MIS_INKY	MIS_IL	240	1,195			0
	MIS_LMI	0	100			0
	PJM_COMD	2,044	3,355			3
	PJM_West	5,441	6,509			3
	S_C_KY	2,257	3,787			6
	S_C_TVA	300	500			6
MIS_LMI	CN_ON	400	1,200			8
	MIS_INKY	0	100			0
	MIS_WUMS	0	100			0
	PJM_ATSI	1,262	2,036			3
	PJM_West	1,400	2,800			3
MIS_MAPP	CN_MB	300	500			8
	MAP_WAUE	1,000	1,500			0
	MIS_MNWI	2,150	5,000			6
MIS_MIDA	MAP_WAUE	600	1,000			6
	MIS_IA	900	2,000			0
	MIS_IL	0	100			0
	MIS_MNWI	0	0			0
	MIS_MO	0	500			0
	PJM_COMD	2,000	3,000			3
	S_D_N_AR	0	30			1
	SPP_N	0	50			6
	SPP_NEBR	1,000	2,000			6
MIS_MNWI	CN_MB	200	1,700			8

From	To	2016 Capacity TTC (MW)	2016 Energy TTC (MW)	2018 Incremental Capacity TTC (MW)	2018 Incremental Energy TTC (MW)	Transmission Tariff (2011 mills/kWh)
	CN_ON	0	162			8
	MAP_WAUE	2,000	3,000			6
	MIS_IA	1,195	2,000			0
	MIS_MAPP	2,150	5,000			6
	MIS_MIDA	0	0			0
	MIS_WUMS	1,480	2,400			0
MIS_MO	MIS_IA	223	711			0
	MIS_IL	3,400	4,500			0
	MIS_MIDA	0	500			0
	S_D_N_AR	2,100	2,804			1
	SPP_N	300	1,000			6
MIS_WUMS	MIS_LMI	0	100			0
	MIS_MNWI	1,480	2,400			0
	PJM_COMD	0	1000			3
NENG_CT	NENGREST	2,600	2,600	800	800	0
	NY_Z_G-I	900	900			3
	NY_Z_K	760	760			3
NENG_ME	CN_NB	800	800			8
	NENGREST	1,600	1,600			0
NENGREST	CN_PQ	1,650	1,650			8
	NENG_CT	2,600	2,600	800	800	0
	NENG_ME	1,600	1,600			0
	NY_Z_D	0	0			3
	NY_Z_F	800	800			3
NY_Z_A&B	CN_ON	1,200	1,200			8
	NY_Z_C&E	1,550	1,550			0
	PJM_PENE	500	1,000			6
NY_Z_C&E	NY_Z_A&B	1,300	1,300			0
	NY_Z_D	1,600	1,600			0
	NY_Z_F	3,250	3,250			0
	NY_Z_G-I	1,700	1,700			0
	PJM_PENE	755	1,500			6
NY_Z_D	CN_PQ	1,200	1,200			8
	NENGREST	150	150			3
	NY_Z_C&E	2,650	2,650			0
NY_Z_F	NENGREST	800	800			3
	NY_Z_C&E	1,999	1,999			0
	NY_Z_G-I	3,450	3,450			0
NY_Z_G-I	NENG_CT	1,130	1,130			3
	PJM_EMAC	1,000	1,000			0
	NY_Z_C&E	1,600	1,600			0
	NY_Z_F	1,999	1,999			0
	NY_Z_J	4,350	4,350			0
	NY_Z_K	1,290	1,290			0
NY_Z_J	NY_Z_G-I	3,500	3,500			0
	NY_Z_K	175	175			0
	PJM_EMAC	1,300	1,900			6
NY_Z_K	NENG_CT	760	760			3
	NY_Z_G-I	530	530			0
	NY_Z_J	283	283			0
	PJM_EMAC	660	660			6

From	To	2016 Capacity TTC (MW)	2016 Energy TTC (MW)	2018 Incremental Capacity TTC (MW)	2018 Incremental Energy TTC (MW)	Transmission Tariff (2011 mills/kWh)
PJM_AP	PJM_ATSI	1,212	2,731			0
	PJM_Dom	5,400	8,000			0
	PJM_PENE	2,400	3,200			0
	PJM_SMAC	1,100	2,200			0
	PJM_West	4,800	6,300			0
PJM_ATSI	MIS_LMI	1,262	2,036			3
	PJM_AP	1,212	2,731			0
	PJM_PENE	0	1,500			0
	PJM_West	7,400	9,700			0
PJM_COMD	MIS_IA	0	600			3
	MIS_IL	2,500	3,000			3
	MIS_INKY	3,840	5,098			3
	MIS_MIDA	2,000	3,000			3
	MIS_WUMS	0	1,000			3
	PJM_West	980	4,000			0
PJM_Dom	PJM_AP	5,400	8,000			0
	PJM_SMAC	1,195	2,812			0
	PJM_West	1,530	3,800			0
	S_VACA	1,000	2,598			6
PJM_EMAC	NY_Z_J	1,300	1,900			6
	NY_Z_K	660	660			6
	NY_Z_G-I	500	500			0
	PJM_SMAC	300	1,095			0
	PJM_WMAC	6,900	6,900			0
PJM_PENE	NY_Z_A&B	500	1,000			6
	NY_Z_C&E	755	1,500			6
	PJM_AP	2,400	3,200			0
	PJM_ATSI	0	1,500			0
	PJM_WMAC	3,565	3,565			0
PJM_SMAC	PJM_AP	1,100	2,200			0
	PJM_Dom	1,195	2,812			0
	PJM_EMAC	300	1,095			0
	PJM_WMAC	800	2,000			0
PJM_West	MIS_IL	0	1,300			3
	MIS_INKY	5,125	6,415			3
	MIS_LMI	1,400	2,800			3
	PJM_AP	4,800	6,300			0
	PJM_ATSI	7,400	9,700			0
	PJM_COMD	980	4,000			0
	PJM_Dom	1,530	3,800			0
	S_C_KY	1,255	2,074			6
	S_C_TVA	2,119	3,118			6
	S_VACA	700	1,000			6
PJM_WMAC	PJM_EMAC	6,900	6,900			0
	PJM_PENE	3,565	3,565			0
	PJM_SMAC	800	2,000			0
S_C_KY	MIS_INKY	2,257	3,787			6
	PJM_West	1,255	2,074			6
S_C_TVA	MIS_IL	1,200	1,500			6
	MIS_INKY	300	500			6
	PJM_West	2,119	3,118			6

From	To	2016 Capacity TTC (MW)	2016 Energy TTC (MW)	2018 Incremental Capacity TTC (MW)	2018 Incremental Energy TTC (MW)	Transmission Tariff (2011 mills/kWh)
	S_D_N_AR	1,732	3,019			8
	S_D_REST	1,195	2,494			8
	S_SOU	3,196	5,098			8
	S_VACA	216	276			8
S_D_AMSO	S_D_REST	2,450	2,450			0
	S_SOU	420	700			8
	SPP_SE	300	500			6
S_D_N_AR	MIS_IA	0	100			1
	MIS_MIDA	0	30			1
	MIS_MO	2,100	2,804			1
	S_C_TVA	1,732	3,019			8
	SPP_N	1,792	2,955			6
	SPP_WEST	2,000	3,000			6
S_D_REST	S_C_TVA	1,195	2,494			8
	S_D_AMSO	2,450	2450			0
	S_D_WOTA	290	1,050			0
	S_SOU	1,700	2,000			8
	SPP_SE	1,639	3,136			6
	SPP_WEST	100	900			6
S_D_WOTA	S_D_REST	1,250	1,250			0
	SPP_SE	1,491	2,835			6
S_SOU	FRCC	3,600	3,600			8
	S_C_TVA	4,411	5,893			8
	S_D_AMSO	420	700			8
	S_D_REST	1,700	2,000			8
	S_VACA	1,400	3,000			8
S_VACA	PJM_Dom	1,000	2,598			6
	PJM_West	700	1,000			6
	S_C_TVA	216	276			8
	S_SOU	1,400	3,000			8
SPP_KIAM	ERC_REST	1,178	1,178			6
	SPP_WEST	1,178	1,178			0
SPP_N	MIS_MIDA	0	50			6
	MIS_MO	300	1,000			6
	S_D_N_AR	1,792	2,955			6
	SPP_NEBR	1,217	1,666	500	500	0
	SPP_SPS	0	900			0
	SPP_WEST	2,253	3,600	500	500	0
SPP_NEBR	MAP_WAUE	700	1,000			6
	MIS_MIDA	1,000	2,000			6
	SPP_N	1,217	1,666	500	500	0
SPP_SE	S_D_AMSO	300	500			6
	S_D_REST	1,639	3,136			6
	S_D_WOTA	1,491	2,835			6
	SPP_WEST	0	852			0
SPP_SPS	SPP_N	0	900			0
	SPP_WEST	1,239	2,205	750	750	0
	WECC_NM	610	610			6
SPP_WEST	ERC_REST	600	600			6
	ERC_WEST	220	220			6
	S_D_N_AR	2,000	3,000			6

From	To	2016 Capacity TTC (MW)	2016 Energy TTC (MW)	2018 Incremental Capacity TTC (MW)	2018 Incremental Energy TTC (MW)	Transmission Tariff (2011 mills/kWh)
	S_D_REST	100	900			6
	SPP_N	2,500	2,700	500	500	0
	SPP_SE	0	688			0
	SPP_SPS	1,239	2,205	750	750	0
WEC_CALN	WECC_NNV	100	100			8
	WECC_PNW	3,675	3,675			8
	WECC_SCE	1,275	1,275			0
	WECC_SF	1,272	1,272			0
WEC_LADW	WECC_AZ	468	468			8
	WECC_PNW	2,858	2,858			8
	WECC_SCE	3,750	3,750			8
	WECC_SNV	3,883	3,883			8
	WECC_UT	1,400	1,400			8
WEC_SDGE	WECC_AZ	1,168	1,168			8
	WECC_IID	150	150			8
	WECC_SCE	2,440	2,440			0
WECC_AZ	WEC_LADW	362	362			8
	WEC_SDGE	1,163	1,163			8
	WECC_IID	195	195			8
	WECC_NM	5,522	5,522			0
	WECC_SCE	1,600	1,600			8
	WECC_SNV	4,727	4,727			0
	WECC_UT	250	250			8
WECC_CO	WECC_NM	614	614			8
	WECC_UT	650	650			8
	WECC_WY	1,400	1,400			0
WECC_ID	WECC_MT	200	200			8
	WECC_NNV	350	350			0
	WECC_PNW	1,800	1,800			8
	WECC_UT	680	680			0
	WECC_WY	0	0			8
WECC_IID	WEC_SDGE	150	150			8
	WECC_AZ	163	163			8
	WECC_SCE	600	600			8
WECC_MT	WECC_ID	325	325			8
	WECC_PNW	2,000	2,000			0
	WECC_WY	400	400			8
WECC_NM	SPP_SPS	610	610			6
	WECC_AZ	5,582	5,582			0
	WECC_CO	664	664			8
	WECC_UT	530	530			8
WECC_NNV	WEC_CALN	100	100			8
	WECC_ID	185	185			0
	WECC_PNW	300	300			8
	WECC_UT	235	235			0
WECC_PNW	CN_BC	1,000	1,000			8
	WEC_CALN	4,200	4,200			8
	WEC_LADW	2,600	2,600			8
	WECC_ID	500	500			8
	WECC_MT	1,000	1,000			0
	WECC_NNV	300	300			8

From	To	2016 Capacity TTC (MW)	2016 Energy TTC (MW)	2018 Incremental Capacity TTC (MW)	2018 Incremental Energy TTC (MW)	Transmission Tariff (2011 mills/kWh)
WECC_SCE	WEC_CALN	3,000	3,000			0
	WEC_LADW	3,750	3,750			8
	WEC_SDGE	2,200	2,200			0
	WECC_AZ	1,082	1,082			8
	WECC_IID	50	50			8
	WECC_SNV	2,814	2,814			8
WECC_SF	WEC_CALN	1,100	1,100			0
WECC_SNV	WEC_LADW	2,300	2,300			8
	WECC_AZ	4,785	4,785			0
	WECC_SCE	1,700	1,700			8
	WECC_UT	250	250			8
WECC_UT	WEC_LADW	1,920	19,20			8
	WECC_AZ	250	250			8
	WECC_CO	650	650			8
	WECC_ID	775	775			0
	WECC_NM	600	600			8
	WECC_NNV	360	360			0
	WECC_SNV	140	140			8
	WECC_WY	400	400			8
WECC_WY	WECC_CO	1,400	1,400			0
	WECC_ID	2,200	2,200			8
	WECC_MT	200	200			8
	WECC_UT	400	400			8

The amount of energy and capacity transferred on a given transmission link is modeled on a seasonal (summer and winter) basis for all run years in the EPA Base Case v.5.13. All of the modeled transmission links have the same Total Transfer Capabilities for both the winter and summer seasons, which means that the maximum firm and non-firm TTCs for each link is the same for both winter and summer. The maximum values for firm and non-firm TTCs were obtained from public sources such as market reports and regional transmission plans, wherever available. Where public sources were not available, the maximum values for firm and non-firm TTCs are based on ICF's expert view. ICF analyzes the operation of the grid under normal and contingency conditions, using industry-standard methods, and calculates the transfer capabilities between regions. ICF uses standard power flow data developed by the market operators, transmission providers, or utilities, as appropriate.

It should be noted that each transmission link between model regions shown in Table 3-4represents a one-directional flow of power on that link. This implies that the maximum amount of flow of power possible from region A to region B may be more or less than the maximum amount of flow of power possible from region B to region A, due to the physical nature of electron flow across the grid.

3.3.2 Joint Transmission Capacity and Energy Limits

Table 3-5 shows the annual joint limits to the transmission capabilities between model regions, which are identical for the firm (capacity) and non-firm (energy) transfers. The joint limits were obtained from public sources where available, or based on ICF's expert view. A joint limit represents the maximum simultaneous firm or non-firm power transfer capability of a group of interfaces. It restricts the amount of firm or non-firm transfers between one model region (or group of model regions) and a different group of model regions). For example, the New England market is connected to the New York market by four transmission links. As shown in Table 3-4, the transfer capabilities from New England to New York for the individual links are:

- NENG_CT to NY_Z_G-I: 900 MW
- NENGREST to NY_Z_F: 800 MW
- NENG_CT to NY_Z_K: 760 MW
- NENGREST to NY_Z_D: 0 MW

Without any simultaneous transfer limits, the total transfer capability from New England to New York would be 2,460 MW. However, current system conditions and reliability requirements limit the total simultaneous transfers from New England to New York to 1,730 MW. ICF uses joint limits to ensure that this and similar reliability limits are not violated. Therefore each individual link can be utilized to its limit as long as the total flow on all links does not exceed the joint limit.

Table 3-5 Annual Joint Capacity and Energy Limits to Transmission Capabilities Between Model Regions in EPA Base Case v.5.13

<table>
<tr><th>Region Connection</th><th>Transmission Path</th><th>Capacity TTC (MW)</th><th>Energy TTC (MW)</th></tr>
<tr><td>NYISO to NYISO</td><td>NY_Z_G-I to NY_Z_K
NY_Z_J to NY_Z_K</td><td colspan="2">1,465</td></tr>
<tr><td>NYISO to NYISO</td><td>NY_Z_K to NY_Z_G-I
NY_Z_K to NY_Z_J</td><td colspan="2">285</td></tr>
<tr><td>NYISO to ISO-NE</td><td>NY_Z_G-I to NENG_CT
NY_Z_F to NENGREST
NY_Z_K to NENG_CT
NY_Z_D to NENGREST</td><td colspan="2">1,730</td></tr>
<tr><td>NYISO to ISO-NE</td><td>NY_Z_G-I to NENG_CT
NY_Z_F to NENGREST
NY_Z_K to NENG_CT
NY_Z_D to NENGREST</td><td colspan="2">2,205</td></tr>
<tr><td>ISO-NE to NYISO</td><td>NENG_CT to NY_Z_G-I
NENGREST to NY_Z_F
NENG_CT to NY_Z_K
NENGREST to NY_Z_D</td><td colspan="2">1,730</td></tr>
<tr><td>PJM to PJM</td><td>PJM_West to PJM_ATSI
PJM_PENE to PJM_ATSI
PJM_AP to PJM_ATSI</td><td>5,417</td><td>12,000</td></tr>
<tr><td>PJM to PJM</td><td>PJM_ATSI to PJM_West
PJM_ATSI to PJM_PENE
PJM_ATSI to PJM_AP</td><td>5,417</td><td>12,000</td></tr>
<tr><td>PJM to SERC-E</td><td>PJM_West to S_VACA
PJM_Dom to S_VACA</td><td>1,300</td><td>2,598</td></tr>
<tr><td>SERC-E to PJM</td><td>S_VACA to PJM_West
S_VACA to PJM_Dom</td><td>1,300</td><td>2,598</td></tr>
<tr><td>MAPP to MISO</td><td>MIS_MAPP to MIS_MNWI
MAP_WAUE to MIS_MNWI</td><td>3,000</td><td>5,000</td></tr>
<tr><td>MISO to MAPP</td><td>MIS_MNWI to MIS_MAPP
MIS_MNWI to MAP_WAUE</td><td>3,000</td><td>5,000</td></tr>
<tr><td>SERC-N to PJM</td><td>S_C_TVA to PJM_West
S_C_KY to PJM_West</td><td>3,000</td><td>4,500</td></tr>
<tr><td>PJM to SERC-N</td><td>PJM_West to S_C_TVA
PJM_West to S_C_KY</td><td>3,000</td><td>4,500</td></tr>
<tr><td>SERC-N to MISO</td><td>S_C_TVA to MIS_INKY
S_C_KY to MIS_INKY</td><td>2,257</td><td>4,000</td></tr>
</table>

Region Connection	Transmission Path	Capacity TTC (MW)	Energy TTC (MW)
MISO to SERC-N	MIS_INKY to S_C_TVA MIS_INKY to S_C_KY	2,257	4,000
MISO to PJM	MIS_INKY to PJM_COMD MIS_INKY to PJM_West	4,586	6,509
PJM to MISO	PJM_COMD to MIS_INKY PJM_West to MIS_INKY	5,998	8,242

3.3.3 Transmission Link Wheeling Charge

Transmission wheeling charge is the cost of transferring electric power from one region to another using the transmission link. The EPA Base Case 5.13 has no charges within individual IPM regions and no charges between IPM regions that fall within the same RTO. Charges between other regions vary to reflect the cost of wheeling. The wheeling charges in 2011 mills/kWh are shown in Table 3-4 in the column labeled “Transmission Tariff”.

3.3.4 Transmission Losses

The EPA Base Case 5.13 assumes a 2.8 percent inter-regional transmission loss of energy transferred.This is based on the average loss factor for the transmission grid calculated from the U.S Energy Information Administration (EIA) State Electricity Profiles 2010 report.[11] The results were validated using average loss factors derived from standard power flow data developed by the market operators, transmission providers, and utilities.

3.4 International Imports

The U.S. electric power system is connected with the transmission grids in Canada and Mexico and the three countries actively trade in electricity. The Canadian power market is endogenously modeled in EPA Base Case v.5.13 but Mexico is not. International electric trading between the U.S. and Mexico is represented by an assumption of net imports based on information from AEO 2013. Table 3-6 summarizes the assumptions on net imports into the US from Mexico.

Table 3-6 International Electricity Imports in EPA Base Case v.5.13

	2016	2018	2020	2025	2030	2040	2050
Net Imports from Mexico (billions kWh)	0.67	0.55	0.31	-0.29	-0.53	-0.53	-0.53

Notes:
Imports & exports transactions from Canada are endogenously modeled in IPM.
Source: AEO 2013

3.5 Capacity, Generation, and Dispatch

While the capacity of existing units is an exogenous input into IPM, the dispatch of those units is an endogenous decision that the model makes. The capacity of existing generating units included in EPA Base Case v.5.13 can be found in the National Electrical Energy Data System (NEEDS v.5.13), a database which provides IPM with information on all currently operating and planned-committed electric generating units. NEEDS v.5.13 is discussed in full in Chapter 4.

A unit’s generation over a period of time is defined by its dispatch pattern over that duration of time. IPM determines the optimal economic dispatch profile given the operating and physical constraints imposed

[11] State Electricity Profiles 2010, Table 3-10, U.S. Energy Information Administration, January 2012. (http://www.eia.gov/electricity/state/pdf/sep2010.pdf).

on the unit. In EPA Base Case v.5.13 unit specific operational and physical constraints are generally represented through availability and turndown constraints. However, for some unit types, capacity factors are used to capture the resource or other physical constraints on generation. The two cases are discussed in more detail in the following sections.

3.5.1 Availability

Power plant "availability" is the percentage of time that a generating unit is available to provide electricity to the grid. Availability takes into account both scheduled maintenance and forced outages; it is formally defined as the ratio of a unit's available hours adjusted for derating of capacity (due to partial outages) to the total number of hours in a year when the unit was in an active state. For most types of units in IPM, availability parameters are used to specify an upper bound on generation to meet demand. Table 3-7 summarizes the availability assumptions used in EPA Base Case v.5.13. They are based on data from NERC Generating Availability Data System (GADS) 2007-2011 and AEO 2012. Table 3-18 shows the availability assumptions for all generating units in EPA Base Case v.5.13.

Table 3-7 Availability Assumptions in the EPA Base Case v.5.13

Unit Type	Annual Availability (%)
Biomass	82 - 86
Coal Steam	77 - 90
Combined Cycle	84 - 90
Combustion Turbine	85 - 93
Fossil Waste	90
Fuel Cell	87
Geothermal	97 - 98
Hydro	81 - 91
IGCC	79 - 88
Landfill Gas	90
Municipal Solid Waste	90
Non-Fossil Waste	90
Nuclear	58 – 100
O/G Steam	70 – 92
Pumped Storage	83 – 90
Solar PV	90
Solar Thermal	90
Tires	90
Wind	95

Notes:
Values shown are a range of all of the values modeled within the EPA Base Case v.5.13. The range depends on the source of information: GADS data vary by size, AEO 2012 data may vary by projected year.

In the EPA Base Case v.5.13, separate seasonal (summer and winter) availabilities are defined. For the fossil and nuclear unit types shown in Table 3-7, summer and winter availabilities differ only in that no planned maintenance is assumed to be conducted during the on-peak summer (June, July and August) months. Characterizing the availability of hydro, solar and wind technologies is more complicated due to the seasonal and locational variations of the resources. The procedures used to represent seasonal variations in hydro are presented in section 3.5.2 and of wind and solar in section 4.4.5.

3.5.2 Capacity Factor

Generation from certain types of units is constrained by resource limitations. These technologies include hydro, wind and solar. For such technologies, IPM uses capacity factors or generation profiles, not availabilities, to define the upper bound on the generation obtainable from the unit. The capacity factor is the percentage of the maximum possible power generated by the unit. For example, a photovoltaic solar unit would have a capacity factor of 27% if the usable sunlight were only available that percent of the time. For such units, explicit capacity factors or generation profiles mimic the resource availability. The seasonal capacity factor assumptions for hydro facilities contained in Table 3-8 were derived from EIA Form-923 data 2007-2011. A discussion of capacity factors and generation profiles for wind and solar technologies is contained in section 4.4.5 and Table 4-32 and Table 4-33.

Table 3-8 Seasonal Hydro Capacity Factors (%) in the EPA Base Case v.5.13

Model Region	Winter Capacity Factor	Summer Capacity Factor	Annual Capacity Factor
ERC_REST	12.9%	25.0%	18.0%
FRCC	44.0%	31.8%	38.9%
MIS_MAPP	81.0%	87.4%	83.7%
MAP_WAUE	29.2%	40.2%	33.8%
MIS_IL	55.0%	64.3%	58.9%
MIS_INKY	76.2%	95.9%	84.4%
MIS_IA	38.5%	48.6%	42.7%
MIS_MIDA	41.6%	49.6%	44.9%
MIS_LMI	68.8%	44.4%	58.6%
MIS_MO	42.7%	58.7%	49.4%
MIS_WUMS	66.2%	61.5%	64.2%
MIS_MNWI	33.0%	36.3%	34.4%
NENG_CT	47.3%	40.2%	44.4%
NENGREST	45.8%	34.5%	41.1%
NENG_ME	65.5%	58.1%	62.4%
NY_Z_C&E	56.9%	55.0%	56.1%
NY_Z_F	67.0%	58.9%	63.6%
NY_Z_G-I	35.8%	34.6%	35.3%
NY_Z_A&B	70.4%	65.0%	68.1%
NY_Z_D	88.3%	83.3%	86.2%
PJM_WMAC	41.5%	20.3%	32.6%
PJM_EMAC	48.3%	24.6%	38.4%
PJM_West	33.8%	28.0%	31.4%
PJM_AP	64.6%	45.5%	56.6%
PJM_COMD	36.5%	48.0%	41.3%
PJM_ATSI	23.5%	32.8%	27.4%
PJM_Dom	21.1%	12.9%	17.7%
PJM_PENE	63.0%	34.1%	50.9%
S_VACA	21.1%	14.2%	18.2%
S_C_KY	29.2%	30.2%	29.6%
S_C_TVA	38.8%	28.3%	34.4%
S_SOU	22.8%	14.5%	19.3%
S_D_WOTA	20.1%	23.0%	21.3%
S_D_N_AR	23.9%	26.7%	25.1%
S_D_REST	49.2%	56.6%	52.3%
SPP_NEBR	32.1%	43.7%	36.9%
SPP_N	15.7%	22.8%	18.7%
SPP_WEST	32.1%	39.9%	35.4%
WECC_ID	32.3%	52.3%	40.7%
WECC_NNV	49.6%	62.6%	55.1%
WECC_UT	30.1%	42.5%	35.3%
WEC_CALN	26.9%	45.1%	34.5%
WECC_IID	45.7%	78.5%	59.5%

Model Region	Winter Capacity Factor	Summer Capacity Factor	Annual Capacity Factor
WEC_LADW	17.1%	27.9%	21.6%
WEC_SDGE	30.8%	53.7%	40.4%
WECC_SCE	28.3%	52.9%	38.6%
WECC_MT	34.4%	52.2%	41.9%
WECC_PNW	41.7%	46.5%	43.7%
WECC_CO	28.8%	36.8%	32.2%
WECC_WY	22.8%	54.1%	36.0%
WECC_AZ	28.9%	33.3%	30.8%
WECC_NM	30.1%	43.0%	35.5%
WECC_SNV	20.4%	25.6%	22.6%

Notes:
Annual capacity factor is provided for information purposes only. It is not directly used in modeling.

Capacity factors are also used to define the upper bound on generation obtainable from nuclear units. This rests on the assumption that nuclear units will dispatch to their availability, and, consequently, capacity factors and availabilities are equivalent. The capacity factors (and, consequently, the availabilities) of existing nuclear units in EPA Base Case v.5.13 vary from region to region and over time. Further discussion of the nuclear capacity factor assumptions in EPA Base Case v.5.13 is contained in Section 4.5.

In EPA Base Case v5.13 capacity factors for oil/gas (O/G) steam units are treated separately and assigned minimum capacity factors under certain conditions. These capacity factors are a result of stakeholder comments that many of the O/G steam units in the national fleet may not operate under the economic conditions reflected in EPA power sector modeling. These comments note that these units often operate due to local transmission constraints, unit-specific grid reliability requirements, or other drivers that are not captured in EPA's modeling. EPA examined its modeling treatment of these units and has introduced minimum capacity factor constraints in EPA Base Case v5.13 to reflect better the real-world behavior of these units where drivers of that behavior are not fully represented in the model itself. This approach is designed to balance the continued operation of these units in the near term while also allowing for economic forces to influence decision-making over the modeling time horizon; as a result, the minimum capacity factor limitations are phased out over time and are completely removed if the capacity in question reaches 60 years of age Review of the historical operation of these units indicate that units with high capacity factors continue at similar levels over time; in order to reflect persistent operation of these units, minimum capacity factors for higher capacity factor units are phased out more slowly than lower capacity factor units. The steps followed in assigning these capacity constraints are as follows:

1) For each O/G steam unit, calculate an seasonal capacity factor over a six year baseline (2007-2012).
2) Identify the minimum capacity factor over this baseline period for each unit.
3) Remove the minimum capacity factor limitation when the unit reaches 60 year old.
4) For units less than 60 years old, remove the constraints based on the assigned minimum capacity factor and the model year, on the following schedule:
   - For model year 2016, keep minimum capacity factor unless unit > 60 years old.
   - For model year 2018, remove minimum constraint from units with capacity factor < 2.5%
   - For model year 2020, remove minimum constraint from units with capacity factor < 5%
   - For model year 2025, remove minimum constraint from units with capacity factor < 15%
   - For model year 2030, remove minimum constraint from units with capacity factor < 25%
   - For model year 2040, remove minimum constraint from units with capacity factor < 45%

3.5.3 Turndown

Turndown assumptions in EPA Base Case v.5.13 are used to prevent coal and oil/gas steam units from operating strictly as peaking units, which would be inconsistent with their operating capabilities. Specifically, the turndown constraints in EPA Base Case v.5.13 require coal steam units to dispatch no less than 50% of the unit capacity in the five base- and mid-load segments of the load duration curve in order to dispatch 100% of the unit in the peak load segment of the LDC. Oil/gas steam units are required to dispatch no less than 25% of the unit capacity in the five base- and mid-load segments of the LDC in order to dispatch 100% of the unit capacity in the peak load segment of the LDC. These turndown constraints were developed by ICF through detailed assessments of the historical experience and operating characteristics of the existing fleet of coal steam and oil/gas steam units' capacities.

3.6 Reserve Margins

A reserve margin is a measure of the system's generating capability above the amount required to meet the net internal demand (peak load) requirement. It is defined as the difference between total dependable capacity and annual system peak load divided by annual system peak load. It is expressed in percent. The reserve margin capacity contribution for renewable units is described in Section 4.4.5; the reserve margin capacity contribution for other units is the dependable capacity in the NEEDS for existing units or the capacity build by IPM for new units. In practice, each NERC region has a reserve margin requirement, or comparable reliability standard, which is designed to encourage electric suppliers in the region to build beyond their peak requirements to ensure the reliability of the electric generation system within the region.

In IPM reserve margins are used to depict the reliability standards that are in effect in each NERC region. Individual reserve margins for each NERC region are derived either directly or indirectly from NERC's electric reliability reports. They are based on reliability standards such as loss of load expectation (LOLE), which is defined as the expected number of days in a specified period in which the daily peak load will exceed the available capacity. EPA Base Case v.5.13 reserve margin assumptions are shown in Table 3-9.

Table 3-9 Planning Reserve Margins in EPA Base Case v.5.13

Model Region	Reserve Margin - Summer	Reserve Margin - Winter
CN_AB	12.2%	11.7%
CN_BC	12.5%	16.2%
CN_MB	12.0%	12.0%
CN_NB	20.0%	20.0%
CN_PE	20.0%	20.0%
CN_NS	20.0%	20.0%
CN_NF	20.0%	20.0%
CN_NL	20.0%	20.0%
CN_ON	19.2%	20.0%
CN_PQ	11.4%	12.2%
CN_SK	11.0%	11.0%
ERC_FRNT	13.8%	13.8%
ERC_GWAY	13.8%	13.8%
ERC_REST	13.8%	13.8%
ERC_WEST	13.8%	13.8%
FRCC	19.3%	19.3%
MAP_WAUE	15.0%	15.0%
MIS_IA	16.3%	16.3%
MIS_IL	16.3%	16.3%
MIS_INKY	16.3%	16.3%
MIS_LMI	16.3%	16.3%
MIS_MAPP	15.0%	15.0%

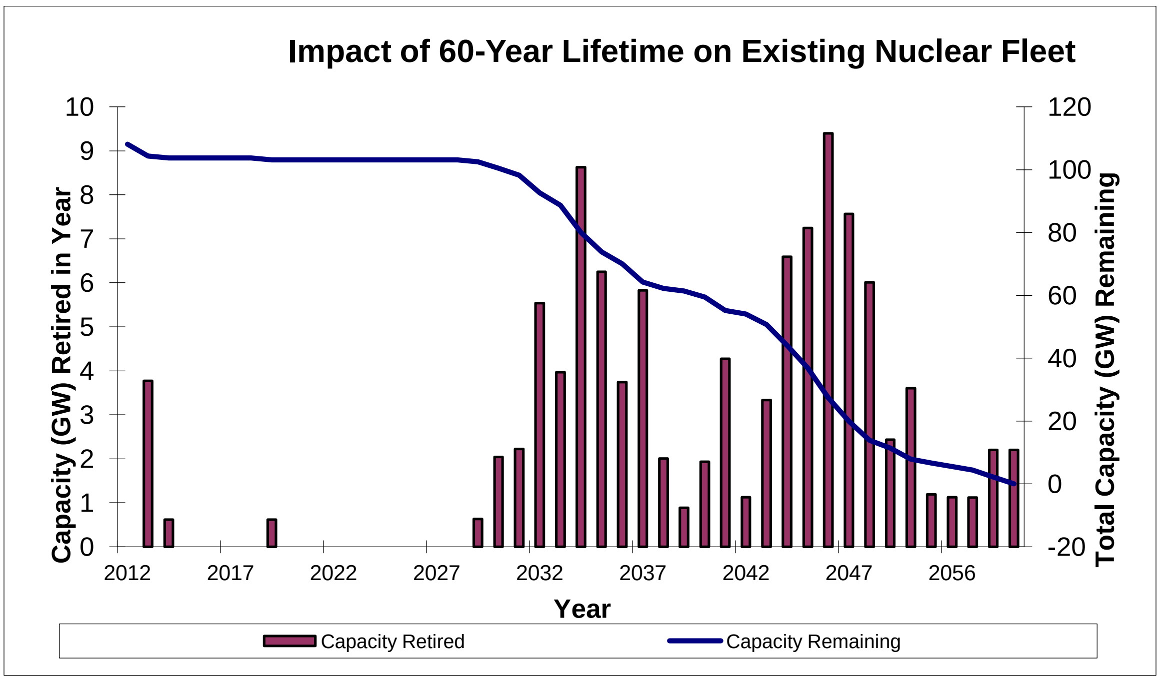
Model Region	Reserve Margin - Summer	Reserve Margin - Winter
MIS_MIDA	16.3%	16.3%
MIS_MNWI	16.3%	16.3%
MIS_MO	16.3%	16.3%
MIS_WUMS	16.3%	16.3%
NENG_CT	15.0%	15.0%
NENG_ME	15.0%	15.0%
NENGREST	15.0%	15.0%
NY_Z_A&B	16.0%	16.0%
NY_Z_C&E	16.0%	16.0%
NY_Z_D	16.0%	16.0%
NY_Z_F	16.0%	16.0%
NY_Z_G-I	16.0%	16.0%
NY_Z_J	16.0%	16.0%
NY_Z_K	16.0%	16.0%
PJM_AP	15.4%	15.4%
PJM_ATSI	15.4%	15.4%
PJM_COMD	15.4%	15.4%
PJM_Dom	15.4%	15.4%
PJM_EMAC	15.4%	15.4%
PJM_PENE	15.4%	15.4%
PJM_SMAC	15.4%	15.4%
PJM_West	15.4%	15.4%
PJM_WMAC	15.4%	15.4%
S_C_KY	15.0%	15.0%
S_C_TVA	15.0%	15.0%
S_D_AMSO	15.0%	15.0%
S_D_N_AR	15.0%	15.0%
S_D_REST	15.0%	15.0%
S_D_WOTA	15.0%	15.0%
S_SOU	15.0%	15.0%
S_VACA	15.0%	15.0%
SPP_KIAM	13.6%	13.6%
SPP_N	13.6%	13.6%
SPP_NEBR	13.6%	13.6%
SPP_SE	13.6%	13.6%
SPP_SPS	13.6%	13.6%
SPP_WEST	13.6%	13.6%
WEC_CALN	14.7%	11.9%
WEC_LADW	15.1%	11.0%
WEC_SDGE	15.1%	11.0%
WECC_AZ	13.5%	14.0%
WECC_CO	14.7%	15.7%
WECC_ID	12.6%	13.5%
WECC_IID	15.1%	11.0%
WECC_MT	17.9%	19.9%
WECC_NM	13.5%	14.0%
WECC_NNV	12.6%	13.5%
WECC_PNW	17.9%	19.9%
WECC_SCE	15.1%	11.0%
WECC_SF	14.7%	11.9%
WECC_SNV	13.5%	14.0%
WECC_UT	12.6%	13.5%
WECC_WY	14.7%	15.7%

3.7 Power Plant Lifetimes

EPA Base Case v5.13 does not include any pre-specified assumptions about power plant lifetimes except for nuclear units. All conventional fossil units (i.e., coal, oil/gas steam, combustion turbines, and combined cycle) and nuclear units can be retired during a model run if their retention is deemed uneconomic. Other types of units are not provided an economic retirement option.

Nuclear Retirement at Age 60: EPA Base Case v.5.13 assumes that commercial nuclear reactors will be retired upon license expiration, which includes a 20 year operating extension that is assumed to be granted for each reactor by the Nuclear Regulatory Commission (NRC). EPA Base Case v.5.13 continues the assumption of a 60 year life from the previous base case platforms. EPA Base Case v.5.13 modeling uses a maximum 60 year lifetime for nuclear reactors based on the current NRC licensing extension program, which states; "Based on the Atomic Energy Act, the Nuclear Regulatory Commission (NRC) issues licenses for commercial power reactors to operate for up to 40 years and allows these licenses to be renewed for up to another 20 years. Economic and antitrust considerations, not limitations of nuclear technology, determined the original 40-year term for reactor licenses. "[12] Today's nuclear fleet totals more than 100 GW. Assuming a 60-year lifetime[13] reduces the current fleet to under 5 GW in 2050. This is illustrated in Figure 3-2. For a complete listing of the existing nuclear units including their online year and other characteristics, see Table 4-34.

Figure 3-2 Scheduled Retirements of Existing Nuclear Capacity Under 60-Year Life Assumption



3.8 Heat Rates

[12] For more info regarding the NRC's licensing extension program, see NRC website: http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/fs-reactor-license-renewal.html.

For an up to date list regarding license renewal status, see "Status of License Renewal Applications and Industry Activities"; NRC website: http://www.nrc.gov/reactors/operating/licensing/renewal/applications.html."

[13] Real-world retirement decisions affecting some nuclear units such as Oyster Creek and San Onofre have occurred prior to those units reaching 60 years in service.

Heat rates, expressed in BTUs per kWh, are a metric of the efficiency of a generating unit. As in previous versions of NEEDS, it is assumed in NEEDS v.5.13 that heat rates of existing units will remain constant over time. This assumption reflects two offsetting factors: (1) plant efficiencies tend to degrade over time and (2) increased maintenance and component replacement work to maintain or improve plant efficiency.

The heat rates in EPA Base Case v.5.13 are based on values from AEO 2013. These values were screened and adjusted using a procedure developed by EPA to ensure that the heat rates used in EPA Base Case v.5.13 are within the engineering capabilities of the generating unit types. Based on engineering analysis, the upper and lower heat rate limits shown in Table 3-10 were applied to coal steam, oil/gas steam, combined cycle, combustion turbine, and internal combustion engines. If the reported heat rate for such a unit was below the applicable lower limit or above the upper limit, the limit was substituted for the reported value.

Table 3-10 Lower and Upper Limits Applied to Heat Rate Data in NEEDS v.5.13

	Heat Rate (Btu/kWh)	
Plant Type	**Lower Limit**	**Upper Limit**
Coal Steam	8,300	14,500
Oil/Gas Steam	8,300	14,500
Combined Cycle - Natural Gas	5,500	15,000
Combined Cycle - Oil	6,000	15,000
Combustion Turbine - Natural Gas - ≥ 80 MW	8,700	18,700
Combustion Turbine - Natural Gas < 80 MW	8,700	36,800
Combustion Turbine - Oil and Oil/Gas - ≥ 80 MW	6,000	25,000
Combustion Turbine - Oil and Oil/Gas < 80 MW	6,000	36,800
IC Engine - Natural Gas	8,700	18,000
IC Engine - Oil and Oil/Gas - 5 MW and above	8,700	20,500
IC Engine - Oil and Oil/Gas < 5 MW	8,700	42,000

3.9 Existing Environmental Regulations

This section describes the existing federal, regional, and state SO_2, NO_x, mercury, HCl and CO_2 emissions regulations that are represented in the EPA Base Case v.5.13. The first four subsections discuss national and regional regulations. The next two subsections describe state level environmental regulations and a variety of legal settlements. The last subsection presents emission assumptions for potential units.

3.9.1 SO_2 Regulations

Unit-level Regulatory SO_2 Emission Rates and Coal Assignments: Before discussing the national and regional regulations affecting SO_2, it is important to note that unit-level SO_2 regulations arising out of State Implementation Plan (SIP) requirements, which are not only state-specific but also county-specific, are captured at model set-up in the coal choices given to coal fired existing units in EPA Base Case v.5.13. The SIP requirements define “regulatory SO_2 emission rates.” Since SO_2 emissions are dependent on the sulfur content of the fuel used, the regulatory SO_2 emission rates are used in IPM to define fuel capabilities.

For instance, a unit with a regulatory SO_2 emission rate of 3.0 lbs/MMBtu would be provided only with those combinations of fuel choices and SO_2 emission control options that would allow the unit to achieve an out-of-stack rate of 3.0 lbs/MMBtu or less. If the unit finds it economical, it may elect to burn a fuel that would achieve a lower SO_2 rate than its specified regulatory emission limit. In EPA Base Case v.5.13 there are six different sulfur grades of bituminous coal, four different grades of subbituminous coal, five different grades of lignite, and one sulfur grade of residual fuel oil. There are two different SO_2 scrubber options and one DSI option for coal units. Further discussion of fuel types and sulfur content is contained in Chapter 9. Further discussion of SO_2 control technologies is contained in Chapter 5.

National and Regional SO_2 Regulations: The national program affecting SO_2 emissions in EPA Base Case v.5.13 is the Acid Rain Program established under Title IV of the Clean Air Act Amendments (CAAA) of 1990, which set a goal of reducing annual SO_2 emissions by 10 million tons below 1980 levels. The program, which became fully operational in year 2000, affects all SO_2 emitting electric generating units greater than 25 MWs. The program provides trading and banking of allowances over time across all affected electric generation sources.

The annual SO_2 caps over the modeling time horizon in EPA Base Case v.5.13 reflect the provisions in Title IV. Since EPA Base Case v.5.13 uses year 2016 as the first analysis year, a projection of allowance banking behavior through the end of 2015 and specification of the available 2016 allowances are needed to initialize the modeling. EPA developed the projection of the banked allowances (30.6 million) going into 2016. Calculating the available 2016 allowances involved deducting allowance surrenders due to NSR settlements and state regulations from the 2016 SO_2 cap of 8.95 million tons. The surrenders totaled 142 thousand tons in allowances, leaving 8.808 million of 2016 allowances remaining. Table 7-4 shows the initial bank and 2016 allowance specification along with the SO_2 caps for the entire modeling time horizon. Specifics of the allowance surrender requirements under state regulations and NSR settlements can be found in Table 3-13 and Table 3-14.

EPA Base Case v.5.13 also includes a representation of the Western Regional Air Partnership (WRAP) Program, a regional initiative involving New Mexico, Utah, and Wyoming directed toward addressing visibility issues in the Grand Canyon and affecting SO_2 emissions starting in 2018. The WRAP specifications for SO_2 are presented in Table 7-4.

3.9.2 NO_x Regulations

Much like SO_2 regulations, existing NO_x regulations are represented in EPA Base Case v.5.13 through a combination of system level NO_x programs and generation unit-level NO_x limits. The NO_x SIP Call trading program is no longer represented since it was replaced by the requirements of the Clean Air Interstate Rule (CAIR), described in section 3.9.4 below. Rhode Island is the only state from the NOx SIP Call that is not covered in CAIR. Its NO_x emission obligations under the NO_x SIP Call are still included in EPA Base Case v.5.13.

By assigning unit-specific NO_x rates based on 2011 data, EPA Base Case v.5.13 is implicitly representing Title IV unit-specific rate limits and Clean Air Act Reasonably Available Control Technology (RACT) requirements for controlling NO_x emissions from electric generating units in ozone non-attainment areas or in the Ozone Transport Region (OTR).[14] Unlike SO_2 emission rates, NO_x emission rates are assumed not to vary with fuel, but are dependent on the combustion properties of the generating unit. Under the EPA Base Case v.5.13 the NO_x emission rate of a unit can only change if the unit is retrofitted with NO_x pollution control equipment or if it is assumed to install state-of-the-art NO_x combustion controls.

<u>NO_x Emission Rates</u>

Future emission projections for NO_x are a product of a unit's utilization (heat input) and emission rate (lbs/mmbtu). A unit's NO_x emission rate can vary significantly depending on the NO_X reduction requirements to which it is subject. For example, a unit may have a post-combustion control installed (e.g., SCR or SNCR), but only operate it during the particular time of the year in which it is subject to NO_x reduction requirements (i.e., the unit only operates its post-combustion control during the ozone season). Therefore, its ozone-season NO_x emission rate would be lower than its non-ozone-season NO_x emission rate. Because the same individual unit can have such large variation in its emission rate, the model needs a suite of emission rate "modes" from which it can select the value most appropriate to the conditions in any given model scenario. The different emission rates reflect the different operational conditions a unit may experience regarding upgrades to its combustion controls and operation of its

[14] The OTR consists of the following states: Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Maryland, District of Columbia, and northern Virginia.

existing post-combustion controls. Four modes of operation are developed for each unit, with each mode carrying a potentially different NO_x emission rate for that unit under those operational conditions.

The emission rates assigned to each mode are derived from historic data (where available) and presented in the NEEDS file. When the model is run, IPM selects one of these four modes through a decision process depicted in

Figure 3-4 below. The four modes address whether or not units upgrade combustion controls and/or operate *existing* post-combustion controls; the modes themselves do not address what happens to the unit's NOx rate if it is projected to add a *new* post-combustion NOx control. In such cases, after the model selects the appropriate mode, the emission rate originally assigned to that mode is further adjusted downward to reflect the retrofit of a SCR or SNCR. In this case, an emission rate is assumed that reflects a percentage removal from the mode's emission rate or an emission rate floor (whichever is greater). The full process for determining the NOx rate of units in EPA Base Case v.5.13 model projections is summarized in Figure 3-3 below.

Figure 3-3 Modeling Process for Obtaining Projected NO_x Emission Rates

NO_x Emission Rates in NEEDS, v.5.13 Database

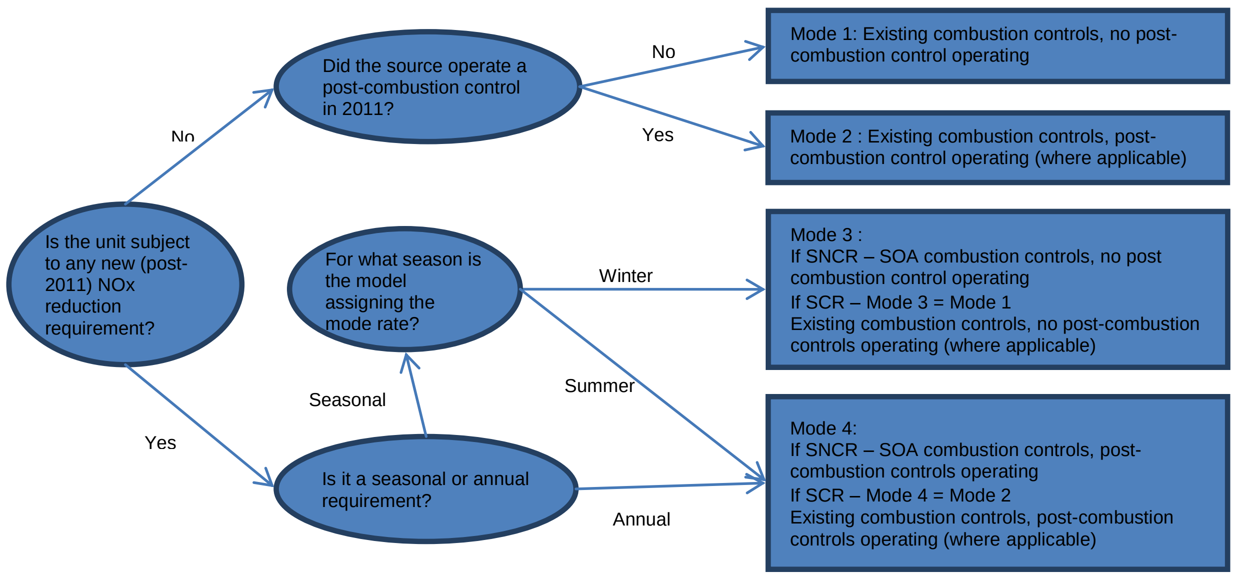
The NO_x rates in the current base case were derived, wherever possible, directly from actual monitored NO_x emission rate data reported to EPA under the Acid Rain and NO_x Budget Program in 2011. The emission rates themselves reflect the impact of applicable NO_x regulations. For coal-fired units, NO_x rates were used in combination with detailed engineering assessments of NO_x combustion control performance to prepare a set of four possible starting NO_x rates to assign to a unit, depending on the specific NO_X reduction requirements affecting that unit in a model run.

The reason for having a framework of four potential NO_x rate "modes" applicable to each unit in NEEDS is to enable the model to select from a range of NO_x rates possible at a unit, given its configuration of NO_x combustion controls and its assumed operation of existing post-combustion controls. There are up to four basic operating states for a given unit that significantly impact its NO_x rate, and thus there are four NO_X rate "modes".

Mode 1: No post-combustion control operating; existing combustion controls
Mode 2: Post-combustion control operating, existing combustion controls
Mode 3: No post-combustion control operating; state-of-the-art (SOA) combustion controls (where applicable)
Mode 4: Post-combustion control operating; state-of-the-art (SOA) combustion controls (where applicable)

Emission rates derived for each unit operating under each of these four modes are presented in the NEEDS file. Note, not every unit has a different emission rate for each mode, because certain units cannot in practice change their NO_x rates to conform to all potential operational states described above. For instance, a unit without a post-combustion control will not have different emission rates between modes 1 and 2, or between modes 3 and 4, as there is no post-combustion control that would potentially turn on or off at these units. For such units, the mode 2 rate will simply equal the mode 1 rate, and the mode 4 rate will equal the mode 3 rate.

Figure 3-4 How One of the Four NO_x Modes Is Ultimately Selected for a Unit



<u>State-of-the-art combustion controls (SOA combustion controls)</u>

The definition of “state-of-the-art” varies depending on the unit type and configuration. Table 3-11 indicates the incremental combustion controls that are required to achieve a “state-of-the-art” combustion control configuration for each unit. For instance if a wall-fired boiler (highlighted below) currently has LNB, the “state-of-the-art” rate calculated for such a unit would assume a NO_x emission rate reflective of overfire air being added at the unit. The cost assumptions behind such an upgrade are described in chapter 5. As described in the attachment of this chapter, the “state-of-the-art” combustion controls reflected in the modes are only assigned to a unit if it is subject to a *new* (post-2011) NO_x reduction requirement (i.e., a NO_x reduction requirement that did not apply to the unit during its 2011 operation that forms the historic basis for deriving NO_x rates for units in Base Case v.5.13). Existing reduction requirements as of 2011 (e.g., NO_x SIP Call) under which units have already made combustion control decisions would not trigger the assignment of the “state-of-the-art” modes that reflect additional combustion controls.

Table 3-11 State-of-the-Art Combustion Control Configurations by Boiler Type

Boiler Type	Existing NO_x Combustion Control	Incremental Combustion Control Necessary to Achieve “State-of-the-Art”
Cell	LNB NGR	OFA LNB AND OFA
Cyclone	--	OFA
Stoker/SPR	--	OFA
Tangential	-- LA LNB LNB + OFA LNC1[a] LNC2 OFA ROFA	LNC3 LNC3 CONVERSION FROM LNC1 TO LNC3 CONVERSION FROM LNC1 TO LNC3 CONVERSION FROM LNC1 TO LNC3 CONVERSION FROM LNC2 TO LNC3 LNC1 LNB
Vertical	--	NO_x Combustion Control - Vertically Fired Units
Wall	-- LA	LNB AND OFA LNB AND OFA

Boiler Type	Existing NO_x Combustion Control	Incremental Combustion Control Necessary to Achieve "State-of-the-Art"
	LNB	OFA
	LNF	OFA
	OFA	LNB

[a] LNC1 = low NO_x coal-and air nozzles with close-coupled overfire air, LNC2 = Low NO_x Coal-and-Air Nozzles with Separated Overfire Air, LNC3 = Low NO_x Coal-and-Air Nozzles with Close-Coupled and Separated Overfire Air

The emission rates for each generating unit under each mode are included in the NEEDS v5.13 database, described in Chapter 4. Attachment 3-1 and accompanying Tables 3-1.1and 3-1.2 give further information on the procedures employed to derive the four NO_x modes.

Additional NO_x rate assumptions include default NO_x rates of 0.23 lbs/MMBtu for existing biomass units and 0.044 lbs/MMBtu for existing landfill gas units.

Because of the complexity of the fleet and the completeness/incompleteness of historic data, there are instances where the derivation of a unit's modeled NO_x emission rate is more detailed than the description provided above. For a more complete step-by-step description of the decision rules used to develop the NO_x rates, please see attachment 3-1.

3.9.3 Multi-Pollutant Environmental Regulations

CAIR

The Clean Air Interstate Rule (CAIR) uses a cap and trade system to reduce the target pollutants—SO_2 and NO_x—for 27 eastern states and DC.[15] CAIR uses Title IV SO_2 allowances as currency for the SO_2 trading program. The initial bank and allowance totals for CAIR are the same as for the Acid Rain Program above. For the Annual NO_x trading program, the total Annual NO_x allowances issued for 2016 was 1.2 million and the initial bank for 2016 was projected to be 1.5 million allowances. For the Ozone Season NO_x trading program, the total seasonal NO_x allowances was 0.48 million and the initial bank going into 2016 was projected to be 0.74 million. Table 7-4shows the initial bank and 2016 allowance specification along with the caps for the entire modeling time horizon.

In 2008, the U.S. Court of Appeals for the District of Columbia Circuit remanded CAIR to EPA to correct legal flaws in the proposed regulations as cited in the Court's July 2008 ruling. The Court allowed EPA to proceed with implementation of the CAIR trading programs while EPA works on a replacement rule addressing the Court's findings. CAIR's provisions were still in effect when EPA Base Case v.5.13 was released and were included in the modeling. For more information on CAIR, go to http://www.epa.gov/cair/.

MATS

Finalized in 2011, the Mercury and Air Toxics Rule (MATS) establishes National Emissions Standards for Hazardous Air Pollutants (NESHAPS) for the "electric utility steam generating unit" source category, which includes those units that combust coal or oil for the purpose of generating electricity for sale and distribution through the electric grid to the public. EPA v.5.13 applies the input-based (lbs/MMBtu) MATS control requirements for mercury and hydrogen chloride to covered units. Treatment of the filterable PM standard in the model is detailed in section 5.6.1. EPA Base Case v.5.13 does not model the alternative SO_2 standard offered under MATS for units to demonstrate compliance with the rule's HCl control requirements. Coal steam units with access to lignite in the modeling are required to meet the "existing

[15] The states included in the Clean Air Interstate Rule are Alabama, Arkansas, Connecticut, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia and Wisconsin.

coal-fired unit low Btu virgin coal" standard. For more information on MATS, go to http://www.epa.gov/mats/.

Regional Haze

The Clean Air Act establishes a national goal for returning visibility to natural conditions through the "prevention of any future, and the remedying of any existing impairment of visibility in Class I areas [156 national parks and wilderness areas], where impairment results from manmade air pollution." On July 1, 1999, EPA established a comprehensive visibility protection program with the issuance of the regional haze rule (64 FR 35714). This rule implements the requirements of section 169B of the CAAA and requires states to submit State Implementation Plans (SIPs) establishing goals and long-term strategies for reducing emissions of air pollutants (including SO_2 and NO_x) that cause or contribute to visibility impairment. The requirement to submit a regional haze SIP applies to all 50 states, the District of Columbia, and the Virgin Islands. Among the components of a long-term strategy is the requirement for states to establish emission limits for visibility-impairing pollutants emitted by certain source types (including EGUs) that were placed in operation between 1962 and 1977. These emission limits are to reflect Best Available Retrofit Technology (BART). States may perform individual point source BART determinations, or meet the requirements of the rule with an approved BART alternative. An alternative regional SO_2 cap for EGUs under Section 309 of the regional haze rule is available to certain western states whose emission sources affect Class 1 areas on the Colorado Plateau.

Since 2010, EPA has approved or, in a very few cases, put in place regional haze Federal Implementation Plans for several states. The BART limits approved in these plans (as of August 29, 2013) that will be in place for EGUs are represented in the EPA Base Case v.5.13 as follows.

- Source-specific NO_x or SO_2 BART emission limits, minimum SO_2 removal efficiency requirements for FGDs, limits on sulfur content in fuel oil, constraints on fuel type (e.g., natural gas only or prohibition of certain fuels such as petroleum coke), or commitments to retire units are applied to the relevant EGUs.
- EGUs in states that rely on CAIR trading programs to satisfy BART must meet the requirements of CAIR.
- EGUs in states that rely on state power plant rules to satisfy BART must meet the emission limits imposed by those state rules.
- For the three western states (New Mexico, Wyoming, and Utah) with approved Section 309 SIPs for SO_2 BART, emission constraints were not applied as current and projected emissions are well under the regional SO_2 cap.

Table 3-19 lists the NO_x and SO_2 limits applied to specific EGUs and other implementations applied in IPM. For more information on Regional Haze Rule, go to: http://www.epa.gov/visibility/program.html

3.9.4 CO_2 Regulations

The Regional Greenhouse Gas Initiative (RGGI) is a CO_2 cap and trade program affecting fossil fired electric power plants 25 MW or larger in Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. Table 7-4 shows the specifications for RGGI that are implemented in EPA Base Case v.5.13.

As part of California's Assembly Bill 32 (AB32), the Global Warming Solutions Act, a multi-sector GHG cap-and-trade program was established that targets 1990 emission levels by 2020. The cap begins in 2013 for electric utilities and large industrial facilities, with distributors of transportation, natural gas and other fuels joining the capped sectors in 2015. In addition to in-state sources, the cap-and-trade program also covers the emissions associated with qualifying, out-of-state EGUs that sell power into California. Due to the inherent complexity in modeling a multi-sector cap-and-trade program where the participation of out-of-state EGUs is determined based on endogenous behavior (i.e. IPM determines whether qualifying out-of-state EGUs are projected to sell power into California), EPA has developed a simplified methodology to model California's cap-and-trade program:

- Adopt the AB32 cap-and-trade allowance price from EIA's AEO2013 Reference Case, which fully represents the non-power sectors. All qualifying fossil-fired EGUs in California are subject to this price signal.
- Estimate a marginal CO_2 emission rate for each IPM region that exports power to California. This rate is assumed to be the CO_2 rate of the model plant with the highest variable cost in EPA Base Case v.5.13.
- For each IPM region that exports power to California, convert the $/ton CO_2 allowance price projection into a mills/kWh transmission wheeling charge using the marginal emission rate from the previous step. The additional wheeling charge for qualifying out-of-state EGUs is equal to the allowance price imposed on affected in-state EGUs. Applying the charge to the transmission link ensures that power imported into California from out-of-state EGUs must account for the cost of CO_2 emissions represented by its generation, such that the model may clear the California market in a manner consistent with AB32 policy treatment of CO_2 emissions.

3.9.5 State-Specific Environmental Regulations

EPA Base Case v.5.13 represents enacted laws and regulations in 26 states affecting emissions from the electricity sector. Table 3-13 summarizes the provisions of state laws and regulations that are represented in EPA Base Case v.5.13.

3.9.6 New Source Review (NSR) Settlements

New Source Review (NSR) settlements refer to legal agreements with companies resulting from the permitting process under the CAAA which requires industry to undergo an EPA pre-construction review of proposed environmental controls either on new facilities or as modifications to existing facilities where there would result a "significant increase" in a regulated pollutant. EPA Base Case v.5.13 includes NSR settlements with 31 electric power companies. A summary of the units affected and how the settlements were modeled can be found in Table 3-14.

Eight state settlements and nine citizen settlements are also represented in EPA Base Case v.5.13. These are summarized in Table 3-15 and Table 3-16 respectively.

3.9.7 Emission Assumptions for Potential (New) Units

Emissions from existing and planned/committed units vary from installation to installation based on the performance of the generating unit and the emissions regulations that are in place. In contrast, there are no location-specific variations in the emission and removal rate capabilities of potential new units. In IPM, potential new units are modeled as additional capacity and generation that may come online in each model region. Across all model regions the emission and removal rate capabilities of potential new units are the same, and they reflect applicable federal emission limitations on new sources. The specific assumptions regarding the emission and removal rates of potential new units in EPA Base Case v.5.13 are presented in Table 3-12. (Note: Nuclear, wind, solar, and fuel cell technologies are not included in Table 3-12 because they do not emit any of the listed pollutants.) For additional details on the modeling of potential new units, see Chapter 4.

3.9.8 Energy Efficiency and Renewable Portfolio Standards

Renewable Portfolio Standards (RPS) generally refers to various state-level policies that require the addition of renewable generation to meet a specified share of state-wide generation. In EPA Base Case v.5.13 the state RPS requirements are represented at a regional level utilizing the aggregate regional representation of RPS requirements that is implemented in AEO 2013 as shown in Table 3-17.[16] This table shows the RPS requirements that apply to the NEMS (National Energy Modeling System) regions used in AEO. In addition, state level solar carve-out requirements have been implemented at a NEMS region level in EPA Base Case v.5.13.

3.10 Capacity Deployment Constraints

EPA Base Case v.5.13 includes capacity deployment constraints for the more capital intensive generation technologies and retrofits (new nuclear, advanced coal with carbon capture, and carbon capture retrofits). The deployment constraints are intended to capture factors that are likely to place an upper bound on the amount of these technologies that can be built in the real world in any given model run year over the modeling time horizon. Such limiting factors include:

- production capacity limitations (including the number of engineering and construction (E/C) firms capable of executing large power projects in the U.S., the number of large projects each such firm can handle, and the number of multi-billion dollar projects a firm can take on in parallel),
- general limitations in the domestic infrastructure for heavy manufacturing,
- financial limitations (number of projects that can obtain financing simultaneously at an acceptable level of risk),
- workforce limitations (limitations in the skilled engineering and construction labor force, replacement challenges caused by an aging workforce, on the one hand, and inadequate training infrastructure for new entrants, on the other).

The capacity deployment constraints are based on assessments by EPA power sector engineering staff of historical trends and projections of capability going forward. Conceptually, the procedure used to develop these constraints consisted of the following steps:

1. Start by estimating the maximum number of E/C firms that will be available over the time horizon.
2. Estimate the maximum number of a particular type of generating unit (e.g., 600 MW advanced coal plant with carbon capture) that a single E/C firm can complete in the first 5-year period (2015-2020).
3. Multiply the number of E/C firms estimated in Step 1 by the number of units per firm found in Step 2 to obtain the maximum number of these generating units that can be completed in the first period.
4. Determine if there will be competition from other competing technologies for the same productive capacity and labor force used for the technology analyzed in steps 2 and 3. If not, go to Step 7. If so, go to Step 5.
5. Establish an equivalency table showing how much capacity could be built if the effort required to build 1 MW of the type of technology analyzed in steps 2 and 3 were instead used to build another type of generating technology (e.g., 1600 MW nuclear plant).
6. Based on these calculations build a production possibility frontier showing the maximum mix of the two generating technologies that can be added in the first 5-year period.
7. Over the subsequent five year periods assume that the E/C firms have increased capabilities relative to the previous five year period. Represent the increased capability by a capability multiplier. For example, it might be assumed that each succeeding 5-year period the E/C firms can design and build 1.4 as much as in the immediately preceding 5-year period. Multiply the capacity deployment limit(s) from the preceding period by the capability multiplier to derive the capacity deployment limit for the subsequent period.

[16] Energy Information Administration, U.S. Department of Energy, *Assumptions to Annual Energy Outlook 2013: Renewable Fuels Module* (DOE/EIA-0554(2010)), April 15, 2013, Table 13.2 "Aggregate Regional Renewable Portfolio Standard Requirements," http://www.eia.gov/forecasts/aeo/assumptions/pdf/renewable.pdf.

8. If necessary, prevent sudden spikes in capacity in later periods when there has been little or no build up in preceding periods by tying the amount of capacity that can be built in a given period to the amount of capacity built in preceding periods.

Attachment 3-2 shows the joint capacity deployment constraint on advanced coal with carbon capture and storage (CCS) and new nuclear. Attachment 3-3 shows the capacity deployment constraint on new nuclear in itself. The bar graph in Attachment 3-3 illustrates how building capacity in earlier years increases the maximum capacity that can be built over the entire modeling time horizon.

Table 3-12 Emission and Removal Rate Assumptions for Potential (New) Units in EPA Base Case v.5.13

	Controls, Removal, and Emissions Rates	Supercritical Pulverized Coal	Integrated Gasification Combined Cycle	Integrated Gasification Combined Cycle with Carbon Sequestration	Advanced Combined Cycle	Advanced Combined Cycle with Carbon Sequestration	Advanced Combustion Turbine	Biomass-Bubbling Fluidized Bed (BFB)	Geothermal	Landfill Gas
SO_2	**Removal / Emissions Rate**	96% with a floor of 0.06 lbs/MMBtu	99%	99%	None	None	None	0.08 lbs/MMBtu	None	None
NO_x	**Emission Rate**	0.07 lbs/MMBtu	0.013 lbs/MMBtu	0.013 lbs/MMBtu	0.011 lbs/MMBtu	0.011 lbs/MMBtu	0.011 lbs/MMBtu	0.02 lbs/MMBtu	None	0.09 lbs/MMBtu
Hg	**Removal / Emissions Rate**	90%	90%	90%	Natural Gas: 0.000138 lbs/MMBtu Oil: 0.483 lbs/MMBtu	Natural Gas: 0.000138 lbs/MMBtu Oil: 0.483 lbs/MMBtu	Natural Gas: 0.000138 lbs/MMBtu Oil: 0.483 lbs/MMBtu	0.57 lbs/MMBtu	3.70	None
CO_2	**Removal / Emissions Rate**	202.8 - 215.8 lbs/MMBtu	202.8 - 215.8 lbs/MMBtu	90%	Natural Gas: 117.08 lbs/MMBtu Oil: 161.39 lbs/MMBtu	90%	Natural Gas: 117.08 lbs/MMBtu Oil: 161.39 lbs/MMBtu	None	None	None
HCL	**Removal / Emissions Rate**	99% 0.0001 lbs/MMBtu	99% 0.0001 lbs/MMBtu	99% 0.0001 lbs/MMBtu						

Attachment 3-1 NO_x Rate Development in EPA Base Case v.5.13

The following questions (Q) and answers (A) are intended to provide further background on the four NO_x rates found in the NEEDS v5.13 database.

Q1: Why are four NO_x rates included in NEEDS?
A1: The four NO_x rates in NEEDS represent a menu of all the NO_x rates applicable to a specific generating unit with only its current configuration of NO_x combustion and post-combustion controls under all the conceivable operating conditions involving NO_x controls that might be modeled in the future. By defining this menu up front for every generating unit, the program that sets up an IPM run can follow a set of decision rules to select the rate(s) appropriate for the unit in the particular scenario being modeled consistent with the unit's existing set of combustion and post-combustion NO_x controls.

Q2: What operational states do the four NO_x rates represent?
A2: Before answering this question, let's name the four NO_x rates that are in NEEDS and the general control states they reflect

Mode 1= Existing combustion controls, no post-combustion control operation
Mode 2= Existing combustion controls, post-combustion control operation (where applicable)
Mode 3= SOA combustion controls (where applicable), no post-combustion control operation
Mode 4 = SOA combustion controls, post-combustion control operation (where applicable)

Please see Figure 3-4 in Section 3.9.2 for an explanation of how the model selects the appropriate NOx mode for each unit in the projection scenario.

Q3: How are emission rates calculated for each unit for each of the four NO_x modes?
A3: We start with the emission data reported to EPA for a specific year under Title IV of the Clean Air Act Amendments of 1990 (Acid Rain Program) and NO_x Budget Program. Using this data, NO_x rates are derived for the summer and winter seasons.

Calculations can get complex, so we'll illustrate it here for coal units only and with the assumption that the data were absolutely complete and consistent with what engineering theory tells us its values should be. Otherwise, we apply additional screens. Explaining the additional steps involved in those anamolous case-by-case evaluations is beyond the scope of this illustration. However, the process below describes how the values would generally be derived:

The procedure employs the following hierarchy of NO_x rate data sources:

1. 2011 ETS
2. Comments on NO_x rate
3. 2009 ETS
4. 2010 EIA Form 860
5. Defaults

The existing coal steam boilers in US are categorized into three groups depending on the configuration of NO_x combustion and post-combustion controls.

Group 1 - Coal boilers without post-combustion NO_x controls
Mode 1 = 2011 ETS Annual Average NO_x Rate
Mode 2 = Mode 1

Mode 3
Mode 3 calculation follows Steps 1-7:

Step 1: Pre-screen units that already have state of art (SOA) combustion controls from units that have non- SOA combustion controls from units that have no combustion controls

Step 2: For units listed as not having combustion controls
Make sure their NO_x rates do not indicate that they really do have SOA control
If Mode 1 > Cut-off (in Table 3-1.1), then Mode 1 = Base NO_x rate. Go to Step 6
If Mode 1 ≤ Cut-off (in Table 3-1.1), then the unit has SOA control and
Mode 3 = Mode 1
Step 3: For units listed as having SOA combustion controls.
Mode 3 = Mode 1
Step 4: For units listed as not having SOA combustion controls
Make sure their NO_x rates do not indicate that they really do have SOA control

If Mode 1 ≤ Cut-off (in Table 3-1.1), then the unit has SOA control and
Mode 3 = Mode 1
If Mode 1 > Cut-off (in Table 3-1.1), then go to Step 5
Step 5: Determine the unit's Base NO_x rate, i.e., the unit's uncontrolled emission rate without combustion controls, using the appropriate equation (not in boldface italics) in Table 3-1.2 to back calculate their Base NO_x rate. Use the default Base NO_x rate values if back calculations can't be performed. Once the Base NO_x rate is obtained, go to Step 6.

Step 6: Use the appropriate equations (in boldface italics) in Table 3-1.2 to calculate the NO_x rate with SOA combustion controls.

Step 7: Compare the value calculated in Step 6 to the applicable NO_x floor rate in Table 3-1.1.

If the value from Step 6 is ≥ floor, use the Step 6 value as Mode 3. Otherwise, use the floor as the Mode 3 NO_x rate.

Mode 4
Mode 4 =Mode 3

Group 2 - Coal boilers with SCR
Pre-screen coal boilers with 2011 ETS NO_x rates into the following four operating regimes. A coal boiler is assumed to be operating its SCR when the seasonal NO_x rate is less than 0.2 lbs/MMBtu

<u>Group 2.1 SCR is not operating in both summer and winter seasons</u>
Follow the NO_x rate rules summarized for Group 1 boilers. No state of the art combustion controls are implemented.
Mode 1 = 2011 ETS Annual Average NO_x Rate Mode 2 = maximum {(1-0.9) * Mode 1, 0.07} Mode 3 = Mode 1
Mode 4 = Mode 2

<u>Group 2.2 SCR is operating in summer only</u>
Mode 1 = 2011 ETS Winter NO_x Rate
Mode 2 = 2011 ETS Summer NO_x Rate
Mode 3 = Mode 1
Mode 4 = Mode 2

<u>Group 2.3 SCR is operating in winter only</u>
Mode 1 = 2011 ETS Summer NO_x Rate
Mode 2 = 2011 ETS Winter NO_x Rate
Mode 3 = Mode 1
Mode 4 = Mode 2

Group 2.4 SCR is operating year-round
Mode 1 = if (2009 ETS Winter NO_x Rate > 0.2, 2009 ETS Winter NO_x Rate, 2011 ETS Annual Average NO_x Rate)[17]
Mode 2 = 2011 ETS Annual Average NO_x Rate
Mode 3 = Mode 1
Mode 4 = Mode 2

Group 3 - Coal boilers with SNCR
Step 1: Pre-screen coal boilers with 2011 ETS NO_x rates to verify if they have not operated their SNCR in both summer and winter seasons. A coal boiler is assumed to be not operating its SNCR when the NO_x rate is greater than 0.3 lbs/MMBtu in both summer and winter seasons.

Group 3.1 SNCR is not operating in both summer and winter seasons
Follow the NO_x rate rules summarized for Group 1 boilers

Step 2: Pre-screen coal boilers with 2011 ETS NO_x rates into the following three operating regimes. First estimate the implied removal for a coal boiler using the following equation:

Implied Removal (%) = ((Winter NO_x Rate – Summer NO_x Rate)/ Winter NO_x Rate) * 100

Second, assign the coal boiler to a specific operating regime based on the following logic.
If Implied Removal > 20% then SNCR is operating in summer season only,
Else if Implied Removal < -20% then SNCR is operating in winter season only,
Else SNCR is operating year-round

Second, assign the coal boiler to a specific operating regime based on the following logic.

Group 3.2 SNCR is operating in summer only
Mode 1 = 2011 ETS Winter NO_x Rate
Mode 2= 2011 ETS Summer NO_x Rate
Mode 3 = same as Group 1 Mode 3
Mode 4 = maximum {(1-0.25) * Mode 3, 0.1} for non FBC units
Mode 4 = maximum {(1-0.50) * Mode 3, 0.08} for FBC units

Note: The (1-.25) and (1-0.5) terms in the equations above represents the NO_x removal efficiencies of SNCR for non FBC and FBC boilers.

Group 3.3 SNCR is operating in winter only
Mode 1= 2011 ETS Summer NO_x Rate
Mode 2 = 2011 ETS Winter NO_x Rate
Mode 3 = same as Group 3.2 Mode 3
Mode 4 = same as Group 3.2 Mode 4

Group 3.4 SNCR is operating year-round
Mode 1= if (2009 ETS Winter NO_x Rate > 0.3, 2009 ETS Winter NO_x Rate, 2011 ETS Annual Average NO_x Rate)
Mode 2 = 2011 ETS Annual Average NO_x Rate
Mode 3 = same as Group 3.2 Mode 3
Mode 4 = Mode 3

Other things worth noting are:

[17] This equation implies that if a unit with a SCR operates year round in ETS 2011 and in winter in ETS 2009, then Mode 1 NO_x rate will reflect SCR operation.

(a) In general, winter NO_x rates reported in EPA's Emission Tracking System were used as proxies for assigning emission rates to Mode 1.
(b) If a unit does not report having combustion controls, but has an emission rate below a specific cut-off rate (shown in Table 3-1.1), it is considered to have combustion controls.
(c) For units with combustion controls that were not state-of-the-art, the derivation of an emission rate reflecting an upgrade to state-of-the-art combustion controls necessitated calculating (as an interim step) the unit's emission rate if it were to "uninstall" its existing combustion controls. That interim "no combustion controls" emission rate becomes the departure point for calculating the unit's emission rate assuming a state-of-the-art combustion control configuration.
(d) The NO_x rates achievable by state-of-the-art combustion controls vary by coal rank (bituminous and subbituminous) and boiler type. The equations used to derive these rates are shown in Table 3-1.2

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Table 3-1.1 Cutoff and Floor NO_x Rates (lb/MMBtu) in EPA Base Case v.5.13

Boiler Type	Cutoff Rate (lbs/MMBtu)			Floor Rate (lbs/MMBtu)		
	Bituminous	Subbituminous	Lignite	Bituminous	Subbituminous	Lignite
Wall-Fired Dry-Bottom	0.43	0.33	0.29	0.32	0.18	0.18
Tangentially-Fired	0.34	0.24	0.22	0.24	0.12	0.17
Cell-Burners	0.43	0.43	0.43	0.32	0.32	0.32
Cyclones	0.62	0.67	0.67	0.47	0.49	0.49
Vertically-Fired	0.57	0.44	0.44	0.49	0.25	0.25

Table 3-1.2 NO_x Removal Efficiencies for Different Combustion Control Configurations in EPA Base Case v.5.13

(State of the art configurations are shown in bold italic.)

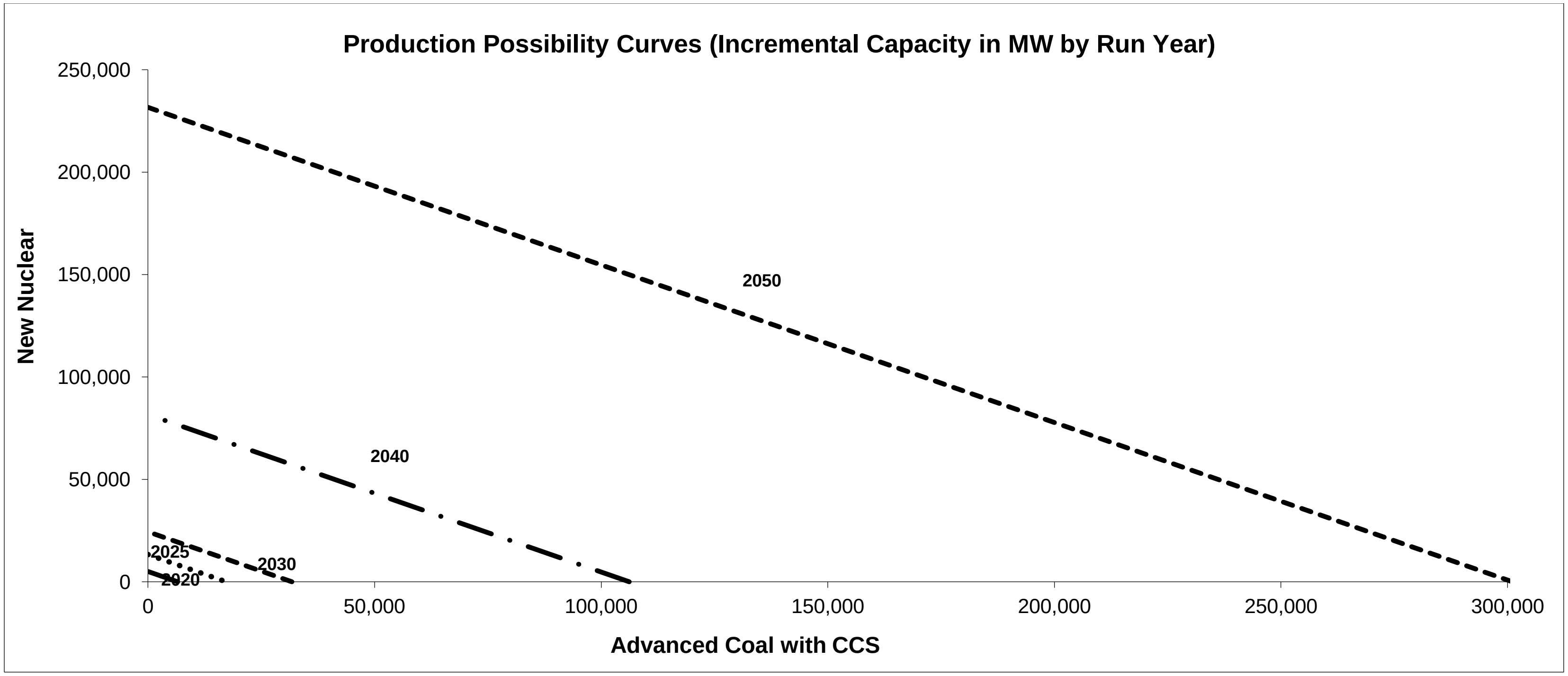
Boiler Type	Coal Type	Combustion Control Technology	Fraction of Removal	Default Removal
Dry Bottom Wall-Fired	Bituminous	LNB	0.163 + 0.272* Base NO_x	0.568
		LNB + OFA	0.313 + 0.272* Base NO_x	0.718
Dry Bottom Wall-Fired	Subbituminous/Lignite	LNB	0.135 + 0.541* Base NO_x	0.574
		LNB + OFA	0.285 + 0.541* Base NO_x	0.724
Tangentially-Fired	Bituminous	LNC1	0.162 + 0.336* Base NO_x	0.42
		LNC2	0.212 + 0.336* Base NO_x	0.47
		LNC3	0.362 + 0.336* Base NO_x	0.62
Tangentially-Fired	Subbituminous/Lignite	LNC1	0.20 + 0.717* Base NO_x	0.563
		LNC2	0.25 + 0.717* Base NO_x	0.613
		LNC3	0.35 + 0.717* Base NO_x	0.713

Notes:
LNB = Low NO_x Burner
OFA = Overfire Air
LNC = Low NO_x Control

Attachment 3-2 Capacity Deployment Limits for Advanced Coal with CCS and New Nuclear in EPA Base Case v.5.13

Run Year	Advanced Coal with CCS (MW)	New Nuclear (MW)
2016	-	-
2018	-	-
2020	6,500	5,000
2025	17,254	13,272
2030	31,750	24,423
2040	106,211	81,701
2050	301,097	231,613

Notes:
The 2020 through 2050 limits for Advanced Coal with CCS and New Nuclear technologies are a joint constraint, with the maximum amount of possible development for each technology shown by run year. If the maximum amount of one technology is developed in a given run year, zero MW of the other may be developed. See the production possibility chart below.



Attachment 3-3 Nuclear Capacity Deployment Constraint in EPA Base Case v.5.13

Run Year	Base New Nuclear Capacity	Base New Nuclear Capacity Deployment Equation	*Possible* Additional New Nuclear Capacity Deployment Equation[1]	Maximum Annual Incremental New Nuclear Capacity Deployment Allowed Equation
2020	5,000	5,000	0	5,000
2025	4,400	0.88 * 2020_Base_Capacity	+ 0.88 * *2020_Incremental_Capacity*	= 0.88 * (*2020_Base_Capacity* + *2020_Incremental_Capacity*)
2030	3,872	0.88 * *2025_Base_Capacity*	+ 0.88 * *2025_Incremental_Capacity*	= 0.88 * (*2025_Base_Capacity* + *2020_Incremental_Capacity*)
2040	19,208	4.96 * *2030_Base_Capacity*	+ 4.96 * *2030_Incremental_Capacity*	= 4.96 * (*2030_Base_Capacity* + *2030_Incremental_Capacity*)
2050	37,648	1.96 * *2040_Base_Capacity*	+ 1.96 * *2040_Incremental_Capacity*	= 1.96 * (*2040_Base_Capacity* + *2040_Incremental_Capacity*)

Run Year	Maximum Possible New Nuclear Capacity Deployment Allowed									
	Deployment Starts 2020		Deployment Starts 2025		Deployment Starts 2030		Deployment Starts 2040		Deployment Starts 2050	
	Incremental	Cumulative	Incremental	Cumulative	Incremental	Cumulative	Incremental	Cumulative	Incremental	Cumulative
2020	5,000	5,000	0	0	0	0	0	0	0	0
2025	8,272	13,272	4,400	4,400	0	0	0	0	0	0
2030	11,151	24,423	7,744	12,144	3,872	3,872	0	0	0	0
2040	57,278	81,701	43,010	55,154	26,797	30,669	19,208	19,208	0	0
2050	149,912	231,613	121,948	177,102	90,170	120,839	75,295	94,503	37,648	37,648

<u>Notes:</u>

No nuclear deployment is allowed before 2020

[1]Addtional new nuclear capacity deployment is *only* possible if nuclear capacity has been built in the previous run year.

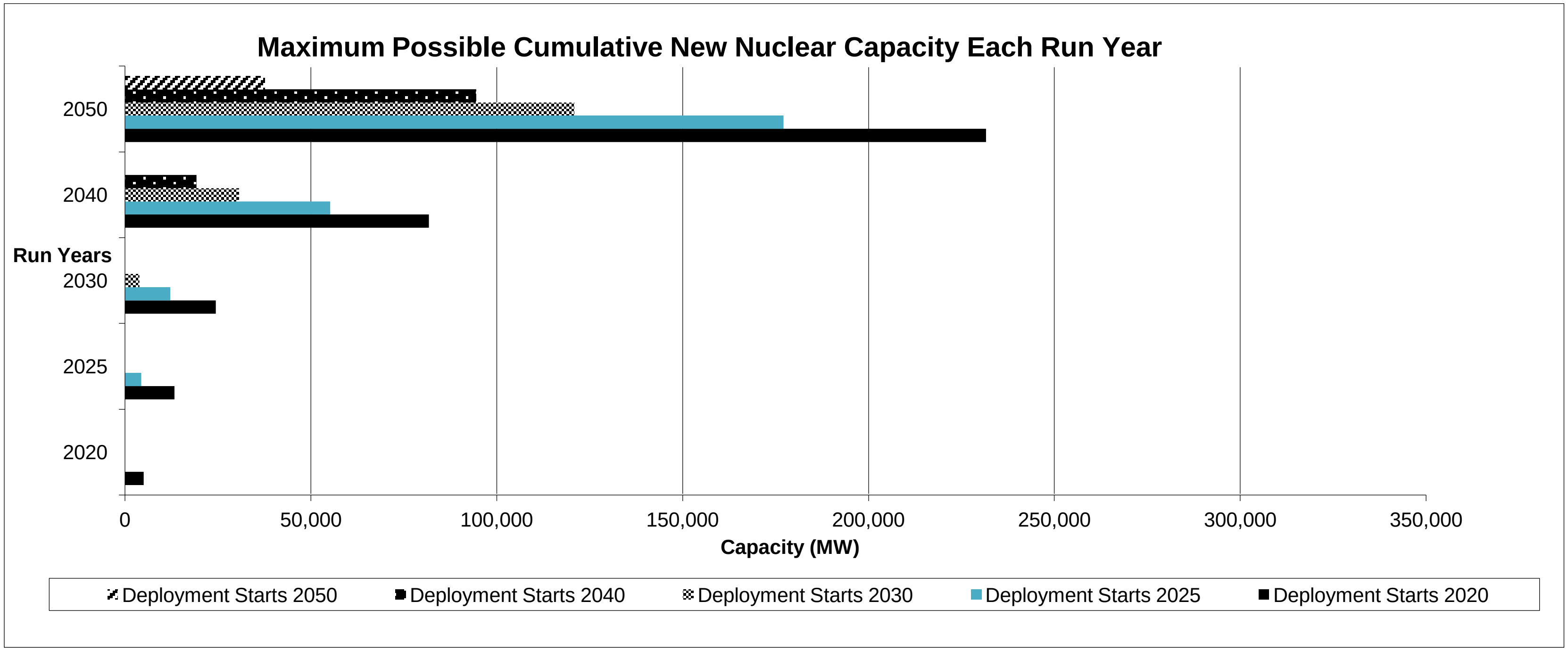

Maximum Possible Cumulative New Nuclear Capacity Each Run Year
Run Years
2050
2040
2030
2025
2020
0
50,000
100,000
150,000
200,000
250,000
300,000
350,000
Capacity (MW)
Deployment Starts 2050
Deployment Starts 2040
Deployment Starts 2030
Deployment Starts 2025
Deployment Starts 2020

Table 3-13 State Power Sector Regulations included in EPA Base Case v.5.13

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
Alabama	Alabama Administrative Code Chapter 335-3-8	NO_x	0.02 lbs/MMBtu for combined cycle EGUs which commenced operation after April 1, 2003; For combined-cycle electric generating units fired by natural gas: 4.0 ppmvd at 15% O2 (0.0178 lbs/MMBtu), by fuel oil- 15.0 ppmvd at 15% O2 (0.0667 lbs/MMBtu)	2003	
Arizona	Title 18, Chapter 2, Article 7	Hg	90% removal of Hg content of fuel or 0.0087 lbs/GWh annual reduction for all non-cogen coal units > 25 MW	2017	
California	CA Reclaim Market	NO_x	9.68 MTons annual cap for list of entities in Appendix A of "Annual RECLAIM Audit Market Report for the Compliance Year 2005" (304 entities)	1994	Since the Reclaim Trading Credits are applicable to entities besides power plants, we approximate by hardwiring the NO_x and SO_2 allowance prices for the calendar year 2006.
		SO_2	4.292 MTons annual cap for list of entities in Appendix A of "Annual RECLAIM Audit Market Report for the Compliance Year 2005" (304 entities)		
	CA AB 32	CO_2	Power sector and Non-power Sector Cap in Million metric tons: 382.40 in 2016, 358.30 in 2018 and 334.20 2020 onwards.	2012	Refer to Section 3.9.4 for details
Colorado	40 C.F.R. Part 60	Hg	2012 & 2013: 80% reduction of Hg content of fuel or 0.0174 lbs/GWh annual reduction for Pawnee Station 1 and Rawhide Station 101. 2014 through 2016: 80% reduction of Hg content of fuel or 0.0174 lbs/GWh annual reduction for all coal units > 25 MW 2017 onwards: 90% reduction of Hg content of fuel or 0.0087 lb/GWh annual reduction for all coal units > 25 MW	2012	
	Clean Air, Clean Jobs Act	NO_x, SO_2, Hg	Retire Arapahoe 3 by 2014; Cherokee 1 & 2 by 2012, Cherokee 3 by 2017; Cameo 1 & 2; Valmont 5 by 2018; W N Clark 55 & 59 by 2015 Convert following units to natural gas: Arapahoe 4 by 2015; Cherokee 4 by 2018 Install SCRs in Hayden 1 & 2 by 2016; SCR + FGD in Pawnee 1 [already installed]	2010	
Connecticut	Executive Order 19 and Regulations of Connecticut State Agencies (RCSA) 22a-174-22	NO_x	0.15 lbs/MMBtu annual rate limit for all fossil units > 15 MW	2003	
	Executive Order 19, RCSA 22a-198 & Connecticut General Statues (CGS) 22a-198	SO_2	0.33 lbs/MMBtu annual rate limit for all fossil units > 25 MW (Title IV Sources) 0.55 lbs/MMBtu annual rate limit for all non-fossil units > 15 MW and fossil units < 25MW and > 15MW (Non-Title IV Sources)		
	Public Act No. 03-72 & RCSA 22a-198	Hg	90% removal of Hg content of fuel or 0.0087 lbs/GWh annual reduction for all coal-fired units	2008	
Delaware	Regulation 1148: Control of Stationary Combustion Turbine EGU Emissions	NO_x	0.19 lbs/MMBtu ozone season PPMDV for stationary, liquid fuel fired CT EGUs >1 MW 0.39 lbs/MMBtu ozone season PPMDV for stationary, gas fuel fired CT EGUs >1 MW	2009	
	Regulation No. 1146: Electric Generating Unit (EGU) Multi-Pollutant Regulation	NO_x	0.125 lbs/MMBtu rate limit of NO_x annually for all coal and residual-oil fired units > 25 MW	2009	The following units have specific NO_x, SO_2, and Hg annual caps in MTons: Edge Moor 3: 0.773 NO_x, 1.391
		SO_2	0.26 lbs/MMBtu annual rate limit for coal and residual-oil fired units > 25 MW		

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
		Hg	2012: 80% removal of Hg content of fuel or 0.0174 lbs/GWh annual reduction for all coal units > 25 MW 2013 onwards: 90% removal of Hg content of fuel or 0.0087 lbs/GWh annual reduction for all coal units > 25 MW	2012	SO_2, & 2012: 0.0000083 Hg, 2013 onwards: 0.0000033 Hg Edge Moor 4: 1.339 NO_x, 2.41 SO_2, & 2012: 0.0000144 Hg, 2013 onwards: 0.0000057 Hg Edge More 5: 1.348 NO_x & 2.427 SO_2 Indian River 3: 0.977 NO_x, 1.759 SO_2, & 2012: 0.0000105 Hg, 2013 onwards: 0.0000042 Hg Indian River 4: 2.032 NO_x, 3.657 SO_2, & 2012: 0.0000219 Hg, 2013 onwards: 0.0000087 Hg McKee Run 3 0.244 NO_x & 0.439 SO_2
	Regulation 1108: Distillate Fuel Oil rule	SO_2	Any relevant units are to use 0.3% sulfur distillate fuel oil		Fuel rule modeled through unit emission rates
Georgia	Multi-pollutant Control for Electric Utility Steam Generating Units	SCR, FGD, and Sorbent Injection Baghouse controls to be installed	The following plants must install controls: Bowen, Branch, Hammond, McDonough, Scherer, Wansley, and Yates	Implementation from 2008 through 2015, depending on plant and control type	
Illinois	Title 35, Section 217.706	NO_x	0.25 lbs/MMBtu summer season rate limit for all fossil units > 25 MW	2003	
	Title 35, Part 225, Subpart B 225.230	Hg	90% removal of Hg content of fuel; or a standard of .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 and ozone season rate limit 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 0.08 lbs/GWh annual reduction for all coal units > 25 MW	2015	
	Title 35 Part 225 Subpart B 225.233 (MPS Ameren specific)	NOx	0.11 lbs/MMBtu annual rate limit and ozone season rate limit Ameren coal steam units > 25 MW	2012	
		SO_2	2015 & 2016 onwards: 0.25 lbs/MMBtu annual rate limit for all Ameren coal steam units > 25 MW 2017 onwards: 0.23 lbs/MMBtu annual rate limit for all Ameren coal steam units > 25 MW	2015	
	Title 35 Part 225; Subpart F: Combined Pollutant Standards (REPEALED)	NO_x	0.11 lbs/MMBtu ozone season and annual rate limit for all specified Midwest Gen coal steam units	2012	REPEALED
		SO_2	0.44 lbs/MMBtu annual rate limit in 2013, decreasing annually to 0.11 lbs/MMBtu in 2019 for all specified Midwest Gen coal steam units	2013	
		Hg	90% removal of Hg content of fuel or 0.08 lbs/GWh annual reduction for all specified Midwest Gen coal steam units	2015	

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
Louisiana	Title 33 Part II - Chapter 22, Control of Nitrogen Oxides	NO_x	For units >/= 80 MMBtu/hr, rate limit in lbs/MMBtu: Coal fired : 0.21 Oil-fired: 0.18 All others (gas or liquid): 0.1 Stationary Sources >/= 10 MMBtu/hr, rate limit in lbs/MMBtu: Oil-fired: 0.3 Gas-fired: 0.2		Applicable for all units in Baton Rouge Nonattainment Area & Region of Influence. Willow Glenn, located in Iberville, obtained a permit that allows its gas-fired units to maintain a cap. These units are separately modeled.
	Title 33, Part III - Chapter 15, Emission Standards for Sulfur Dioxide	SO_2	1.2 lbs/MMBtu ozone season ppmvd for all single point sources that emit or have the potential to emit 5 tons or more of SO_2	2005	
Maine	Chapter 145 NO_x Control Program	NO_x	0.22 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW built before 1995 with a heat input capacity < 750 MMBtu/hr. 0.15 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW built before 1995 with a heat input capacity > 750 MMBtu/hr. 0.20 lbs/MMBtu annual rate limit for all fossil fuel fired indirect heat exchangers, primary boilers, and resource recovery units with heat input capacity > 250 MMBtu/hr	2005	
	38 MRSA Section 603-A Low Sulfur in Fuel Rule	SO_2	All fossil units require the use of 0.5% sulfur residual oil [0.52 lbs/MMBtu]	2018	Fuel rule modeled through unit emission rates
	Statue 585-B Title 38, Chapter 4: Protection and Improvement of Air	Hg	25 lbs annual cap for any facility including EGUs	2010	
Maryland	Maryland Healthy Air Act	NO_x	7.3 MTons summer cap and 16.7 MTons annual cap for 15 specific existing coal steam units	2009	
		SO_2	2009 through 2012: 48.6 MTons annual cap for 15 specific existing coal steam units 2013 onwards: 37.2 MTons annual cap for 15 specific existing coal steam units		
		Hg	2010 through 2012: 80% removal of Hg content of fuel for 15 specific existing coal steam units 2013 onwards: 90% removal of Hg content of fuel for 15 specific existing coal steam units		
Massachusetts	310 CMR 7.29	NO_x	1.5 lbs/MWh annual GPS for Brayton Point, Mystic Generating Station, Mount Tom, Canal, and Salem Harbor	2006	
		SO_2	3.0 lbs/MWh annual GPS for Brayton Point, Mystic Generating Station, Mount Tom, Canal, and Salem Harbor		
		Hg	2012: 85% removal of Hg content of fuel or 0.00000625 lbs/MWh annual GPS for Brayton Point, Mystic Generating Station, Mount Tom, Canal, and Salem Harbor 2013 onwards: 95% removal of Hg content of fuel or 0.0000025 lbs/MWh annual GPS for Brayton Point, Mystic Generating Station, Mount Tom, Canal, and Salem Harbor		Brayton units 1 through 3 have an annual Hg cap of 0.0000733 MTons Mt. Tom 1 has an annual Hg cap of 0.00000205 MTons Salem Harbor units 1 through 3 have an annual Hg cap of 0.0000106 MTons
	310 CMR 7.04	SO_2	Sulfur in Fuel Oil Rule requires the use of 0.5% sulfur residual oil [0.52 lbs/MMBtu] by July 1, 2014 for units greater than 250 MMBtu energy input; by July 1, 2018 for all residual oil units except for those located in the Berkshire APCD.	2014	Fuel rule modeled through unit emission rates

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
Michigan	Part 18 Rules – R 336.1801 (2) (a)	NO_x	For all fossil units > 25 MW, and annual PTE of NO_x >25 tons,.25 lbs/MMBtu ozone season rate, OR 65% NO_x reductions from 1990 levels	2004	
	Part 18 Rules – R 336.1801 (2) (a)	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 with >500,000 lbs Steam per Hour Plant Capacity: 1.67		
	Part 15. Emission Limitations and Prohibitions - Mercury	Hg	90% removal of Hg content of fuel annually for all coal units > 25 MW	2015	
Minnesota	Minnesota Hg Emission Reduction Act	Hg	90% removal of Hg content of fuel annually for all coal facilities > 500 MW combined; Dry scrubbed units must implement by December 31, 2010; Wet scrubbed units must implement by December 31, 2014.	2006	
Missouri	10 CSR 10-6.350	NO_x	0.25 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW in the following counties: Bollinger, Butler, Cape Girardeau, Carter, Clark, Crawford, Dent, Dunklin, Gasconade, Iron, Lewis, Lincoln, Madison, Marion, Mississippi, Montgomery, New Madrid, Oregon, Pemiscot, Perry, Phelps, Pike, Ralls, Reynolds, Ripley, St. Charles, St. Francois, Ste. Genevieve, Scott, Shannon, Stoddard, Warren, Washington and Wayne 0.18 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW the following counties: City of St. Louis, Franklin, Jefferson, and St. Louis 0.35 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW in the following counties: Buchanan, Jackson, Jasper, Randolph, and any other county not listed	2004	
Montana	Montana Mercury Rule Adopted 10/16/06	Hg	0.90 lbs/TBtu annual rate limit for all non-lignite coal units 1.50 lbs/TBtu annual rate limit for all lignite coal units	2010	
New Hampshire	RSA 125-O: 11-18	Hg	80% reduction of aggregated Hg content of the coal burned at the facilities for Merrimack Units 1 & 2 and Schiller Units 4, 5, & 6	2012	
	ENV-A2900 Multiple pollutant annual budget trading and banking program	NO_x	2.90 MTons summer cap for all fossil steam units > 250 MMBtu/hr operated at any time in 1990 and all new units > 15 MW 3.64 MTons annual cap for Merrimack 1 & 2, Newington 1, and Schiller 4 through 6	2007	
		SO_2	7.29 MTons annual cap for Merrimack 1 & 2, Newington 1, and Schiller 4 through 6		
	Env -A 2300 - Mitigation of Regional Haze	SO_2	90% SO_2 control at Merrimack 1 & 2; 0.5 lb SO_2/MMBtu 30 day rolling average at Newington 1	2013	
		NO_x	0.30 lb NO_x/MMBtu 30-day rolling average at Merrimack 2; 0.35 lb NO_x/MMBtu when burning oil and 0.25 lb NO_x/MMBtu when burning oil and gas at Newington 1(permit condition).		
New Jersey	N.J.A.C. 7:27-27.5, 27.6, 27.7, and 27.8	Hg	90% removal of Hg content of fuel annually for all coal-fired units or <= 3.0 mg/MWh (net) 95% removal of Hg content of fuel annually for all MSW incinerator units or <= 28 ug/dscm	2007	
	N.J. A. C. Title 7, Chapter 27, Subchapter 19, Table 1	NO_x	Annual rate limits in lbs/MMBtu for the following technologies: 1.0 for tangential and wall-fired wet-bottom coal boilers serving an EGU 0.60 for cyclone-fired wet-bottom coal boilers serving an EGU	2007	

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
	N.J. A. C. Title 7, Chapter 27, Subchapter 19, Table 2	NO_x	Annual rate limits in lbs/MMBtu for the following technologies: 0.38 for tangential dry-bottom coal boilers serving an EGU 0.45 for wall-fired dry-bottom coal boilers serving an EGU 0.55 for cyclone-fired dry-bottom coal boilers serving an EGU	2007	
	N.J. A. C. Title 7, Chapter 27, Subchapter 19, Table 3	NO_x	Annual rate limits in lbs/MMBtu for the following technologies: 0.20 for tangential oil and/or gas boilers serving an EGU 0.28 for wall-fired oil and/or gas boilers serving an EGU 0.43 for cyclone-fired oil and/or gas boilers serving an EGU	2007	
	N.J. A. C. Title 7, Chapter 27, Subchapter 19, Table 6; non- High Electricity demand Day (HEDD) unit	NO_x	2.2 lbs/MWh annual GPS for gas-burning simple cycle combustion turbine units 3.0 lbs/MWh annual GPS for oil-burning simple cycle combustion turbine units 1.3 lbs/MWh annual GPS for gas-burning combined cycle CT or regenerative cycle CT units 2.0 lbs/MWh annual GPS for oil-burning combined cycle CT or regenerative cycle CT units	2007	
	N.J. A. C. Title 7, Chapter 27, Subchapter 19, Table 7; High Electricity demand Day (HEDD) unit	NO_x	1.0 lbs/MWh annual GPS for gas-burning simple cycle combustion turbine units 1.6 lbs/MWh annual GPS for oil-burning simple cycle combustion turbine units 0.75 lbs/MWh annual GPS for gas-burning combined cycle CT or regenerative cycle CT units 1.2 lbs/MWh annual GPS for oil-burning combined cycle CT or regenerative cycle CT units	2007	On and after May 1, 2015, the owner or operator of a stationary combustion turbine that is a HEDD unit or a stationary combustion turbine that is capable of generating 15 MW or more and that commenced operation on or after May 1, 2005 shall comply with limits outlines "in Table 7 during operation on high electricity demand days, regardless of the fuel combusted, unless combusting gaseous fuel is not possible due to gas curtailment."
New York	Part 237	NO_x	39.91 Mtons [Thousand tons] non-ozone season cap for fossil fuel units > 25 MW	2004	
	Part 238	SO_2	131.36 MTons [Thousand tons] annual cap for fossil fuel units > 25 MW	2005	
	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. 0.60 lbs/TBtu annual rate limit for all coal units > 25 MW developed after Nov.15 1990	2010	
	Subpart 227-2 Reasonably Available Control Technology (RACT) For Major Facilities of Oxides Of Nitrogen (NO_x)	NO_x	Annual rate in lbs/MMBtu for very large boilers >250 MMBtu/hr that commenced operation prior to July 1, 2014; Gas only, tangential & wall fired : 0.2 Gas/oil tangential & wall fired : 0.25; cyclone: 0.43 Coal Wet Bottom, tangential & wall fired : 0.1; cyclone: 0.6 Coal Dry Bottom, tangential: 0.42; wall fired : 0.45; stokers: 0.301 Annual rate in lbs/MMBTu for very large boilers >250 MMBtu/hr that commenced operation after July 1, 2014; Gas only, tangential & wall fired : 0.8 Gas/oil tangential & wall fired : 0.15; cyclone: 0.2 Coal Wet Bottom, tangential & wall fired : 0.12; cyclone: 0.2 Coal Dry Bottom, tangential & wall fired : 0.12; stokers: 0.08	2004	

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
			Annual rate in lbs/MMBTu for large boilers between 100 and 250 MMBtu/hr that commenced operation prior to July 1, 2014; Gas Only: 0.20 Gas/Oil: 0.30 Pulverized Coal: 0.50 Coal (Overfeed Stoker):0.301 Annual rate in lbs/MMBTu for large boilers between 100 and 250 MMBtu/hr that commenced operation after July 1, 2014; Gas Only: 0.06 Gas/Oil: 0.15 Pulverized Coal: 0.20 Coal (Overfeed Stoker/FBC): 0.8		
			Annual rate in lbs/MMBTu for mid-size boilers between 25 and 100 MMBtu/hr that commenced operation prior to July 1, 2014; Gas Only: 0.10 Distillate Oil/Gas: 0.12 Residual Oil/Gas: 0.30 Annual rate in lbs/MMBTu for mid-size boilers between 25 and 100 MMBtu/hr that commenced operation after July 1, 2014; Gas Only: 0.05 Distillate Oil/Gas: 0.08 Residual Oil/Gas: 0.20		
			For **simple cycle and regenerative combustion turbines:** (i) 50 parts per million on a dry volume basis (ppmvd), corrected to 15 percent oxygen, for sources designed to burn gaseous fuels (gaseous fuels include, but are not limited to, natural gas, landfill gas, and digester gas) only; and (ii) 100 ppmvd, corrected to 15 percent oxygen, for sources capable of firing distillate oil or more than one fuel.		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.
			For **combined cycle combustion turbines**: (i) prior to July 1, 2014, 42 ppmvd (0.1869 lbs/MMBtu), corrected to 15 percent oxygen, when firing gas; and (ii) prior to July 1, 2014, 65 ppmvd (0.2892 lbs/MMBtu), corrected to 15 percent oxygen, when firing oil.		
			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: (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.		
	Part 251	CO_2	1450 lbs/MWh rate limit for New Combustion Turbines =>25MW 925 lbs/MWh rate limit for New Fossil Fuel except CT =>25MW	2012	

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
North Carolina	NC Clean Smokestacks Act: Statute 143-215.107D	NO_x	25 MTons annual cap for Progress Energy coal plants > 25 MW and 31 MTons annual cap for Duke Energy coal plants > 25 MW	2007	
		SO_2	2012: 100 MTons annual cap for Progress Energy coal plants > 25 MW and 150 MTons annual cap for Duke Energy coal plants > 25 MW 2013 onwards: 50 MTons annual cap for Progress Energy coal plants > 25 MW and 80 MTons annual cap for Duke Energy coal plants > 25 MW	2009	
	SECTION .2500 – Mercury Rules for Electric Generators	Hg	Coal-fired electric steam >25 MW to comply with the mercury emission caps of 1.133 tons (36,256 ounces) per year between 2010 and 2017 inclusive and 0.447 tons (14,304 ounces) per year for 2018 and thereafter	2010	Vacated
	15A NCAC 02D .2511	Hg	Duke Energy and Progress Energy Hg control plans submitted on January 1, 2013 and are awaiting approval. All control technologies and limitations must be implemented by December 31, 2017.	2017	
Oregon	Oregon Administrative Rules, Chapter 345, Division 24	CO_2	675 lbs/MWh annual rate limit for new combustion turbines burning natural gas with a CF >75% and all new non-base load plants (with a CE <= 75%) emitting CO_2	1997	
	Oregon Utility Mercury Rule - Existing Units	Hg	90% removal of Hg content of fuel reduction or 0.6 lbs/TBtu limitation for all existing coal units >25 MW	2012	
	Oregon Utility Mercury Rule - Potential Units	Hg	25 lbs limit for all potential coal units > 25 MW	2009	
Texas	Senate Bill 7 Chapter 101	SO_2	273.95 MTons cap of SO_2 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	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 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		
			Houston/Galveston region annual Cap and Trade (MECT) for all fossil units: 17.57 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		
Utah	R307-424 Permits: Mercury Requirements for Electric Generating Units	Hg	90% removal of Hg content of fuel annually for all coal units > 25 MW	2013	
Washington	Washington State House Bill 3141	CO_2	$1.45/MTons cost (2004$) for all new fossil-fuel power plant	2004	

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
	Washington State House Bill 5769	CO_2	1100 lbs/MWh rate limit for new coal plants	2011	
Wisconsin	NR 428 Wisconsin Administration Code	NO_x	Annual rate limits in lbs/MMBtu for coal fired boilers > 1,000 MMBtu/hr : Wall fired, tangential fired, cyclone fired, and fluidized bed: 2013 onwards: 0.10 Arch fired: 2009 onwards: 0.18	2009	
			Annual rate limits in lbs/MMBtu for coal fired boilers between 500 and 1,000 MMBtu/hr: Wall-fired with a heat release rate=> 17,000 Btu per cubic feet per hour; 2013 onwards: 0.17 ; if heat input is lesser: Tangential fired: 2009 onwards: 0.15 Cyclone fired: 2013 onwards: 0.15 Fluidized bed: 2013 onwards: 0.10 Arch fired: 2009 onwards: 0.18		
			Annual rate limits in lbs/MMBtu for coal fired boilers between 250 and 500 MMBtu/hr: Same as for coal boiled between 500 and 1000 MMBtu/hr in addition to: Stoker Fired: .20		
			Annual rate limits in lbs/MMBtu for coal fired boilers between 50 and 250 MMBtu/hr: Same as for coal boiled between 500 and 1000 MMBtu/hr in addition to: Stoker Fired: .25		
			Annual rate limits for CTs in lbs/MMBtu: Natural gas CTs > 50 MW: 0.11 Distillate oil CTs > 50 MW: 0.28 Biologically derived fuel CTs > 50 MW: 0.15 Natural gas CTs between 25 and 49 MW: 0.19 Distillate oil CTs between 25 and 49 MW: 0.42 Biologically derived fuel CTs between 25 and 49 MW: 0.15		
			Annual rate limits for CCs in lbs/MMBtu: Natural gas CCs > 25 MW: 0.04 Distillate oil CCs > 25 MW: 0.19 Biologically derived fuel CCs > 25 MWs: 0.15 Natural gas CCs between 10 and 24 MW: 0.19		
	Chapter NR 44.12/446.13 Control of Mercury Emissions	Hg	Large (150MW capacity or greater) or small (between 25 and 150 MW) coal-fired EGU, 2015 onwards: 90% removal of Hg content of fuel or 0.0080 lbs/GWh reduction in coal fired EGUs > 150 MW	2015	
	Chapter NR 446.14 Multi-pollutant reduction alternative for coal-fired electrical generating units	Hg	All Coal>25MW; 70% reduction in fuel, or .0190 lbs per GW-hr from CY 2015 – CY 2017 (0.00005568 lbs/MMBtu) 80% reduction in fuel, or .0130 lbs per GW-hr from CY2018 – CY 2020 (0.0000381 lbs/MMBtu) 90% reduction in fuel, or .0080 lbs per GW-hr from January 1, 2021 onwards (0.00000234 lbs/MMBtu)	2015	Alternative already modeled in IPM
		SO_2	All Coal>25MW; .10 lbs per mmBTU by January 1, 2015		
		NO_x	All Coal>25MW; 07 lbs per mmBTU by January 1, 2015		

Table 3-14 New Source Review (NSR) Settlements in EPA Base Case v.5.13

			Settlement Actions															
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
Company and Plant	State	Unit	Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	Notes	Reference
Alabama Power																		
James H. Miller	Alabama	Unit 3			Install and operate FGD continuously	95%	12/31/11	Operate existing SCR continuously	0.1	05/01/08		0.03	12/31/06	Within 45 days of settlement entry, APC must retire 7,538 SO_2 emission allowances.	APC shall not sell, trade, or otherwise exchange any Plant Miller excess SO_2 emission allowances outside of the APC system	1/1/21	1) Settlement requires 95% removal efficiency for SO_2 or 90% in the event that the unit combust a coal with sulfur content greater than 1% by weight. 2) The settlements require APC to retire $4,900,000 of SO_2 emission allowances within 45 days of consent decree entry. 3) EPA assumed a retirement of 7, 538 SO_2 allowances based on a current allowance price of $650.	http://www2.epa.gov/enforcement/alabama-power-company-clean-air-act-settlement
	Alabama	Unit 4			Install and operate FGD continuously	95%	12/31/11	Operate existing SCR continuously	0.1	05/01/08		0.03	12/31/06			1/1/21		
Minnkota Power Cooperative																		
			Beginning 1/01/2006, Minnkota shall not emit more than 31,000 tons of SO_2/year, no more than 26,000 tons beginning 2011, no more than 11,500 tons beginning 1/01/2012. If Unit 3 is not operational by 12/31/2015, then beginning 1/01/2014, the plant wide emission shall not exceed 8,500.															-
Milton R. Young	North Dakota	Unit 1			Install and continuously operate FGD	95% if wet FGD, 90% if dry	12/31/11	Install and continuously operate Over-fire AIR, or equivalent technology with emission rate < .36	0.36	12/31/09		0.03 if wet FGD, .015 if dry FGD		Plant will surrender 4,346 allowances for each year 2012 – 2015, 8,693 allowances for years 2016 – 2018, 12,170 allowances for year 2019, and 14,886 allowances/year thereafter if Units 1 – 3 are operational by 12/31/2015. If only Units 1 and 2 are operational by12/31/2015, the plant shall retire 17,886 units in 2020 and thereafter.	Minnkota shall not sell or trade NO_x allowances allocated to Units 1, 2, or 3 that would otherwise be available for sale or trade as a result of the actions taken by the settling defendants to comply with the requirements		1) Settlement requires 95% removal efficiency for SO_2 at Unit 1 if a wet FGD is installed, or 90% if a dry FGD is installed. The FGD for Units 1 and 2 and the NO_x control for Unit 1 are modeled as emission constraints in EPA Base Case, the NO_x control for Unit 2 is hardwired into EPA Base Case. 2) Beginning 12/31/2010, Unit 2 will achieve a phase II average NO_x emission rate established through its NO_x BACT determination. Beginning 12/31/2011, Unit 1 will achieve a phase II NO_x emission rate established by its BACT determination.	http://www2.epa.gov/enforcement/minnkota-power-cooperative-and-square-butte-electric-cooperative-settlement
	North Dakota	Unit 2			Design, upgrade, and continuously operate FGD	90%	12/31/10	Install and continuously operate over-fire AIR, or equivalent technology with emission rate < .36	0.36	12/31/07		0.03	Before 2008					
SIGECO																		
FB Culley	Indiana	Unit 1	Repower to natural gas (or retire)	12/31/06										The provision did not specify an amount of SO_2 allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.				http://www2.epa.gov/enforcement/southern-indiana-gas-and-electric-company-sigeco-fb-culley-plant-clean-air-act-caa
	Indiana	Unit 2			Improve and continuously operate existing FGD (shared by Units 2 and 3)	95%	06/30/04											
	Indiana	Unit 3			Improve and continuously operate existing FGD (shared by Units 2 and 3)	95%	06/30/04	Operate Existing SCR Continuously	0.1	09/01/03	Install and continuously operate a Baghouse	0.015	06/30/07					
PSEG FOSSIL																		
Bergen	New Jersey	Unit 2	Repower to combined cycle	12/31/02										The provision did not specify an amount of SO_2 allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.				http://www2.epa.gov/enforcement/pseg-fossil-llc-settlement
Hudson	New Jersey	Unit 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/06	Install SCR (or approved tech) and continually operate	0.1	05/01/07	Install Baghouse (or approved technology)	0.015	12/31/06				The settlement requires coal with monthly average sulfur content no greater than 2% at units operating FGD -- this limit is modeled as a coal choice exception in EPA Base Case.	

Company and Plant	State	Unit	Settlement Actions														Notes	Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date		
Mercer	New Jersey	Unit 1			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		0.015	12/31/10				The settlement requires coal with monthly average sulfur content no greater than 2% at units operating FGD -- this limit is modeled as a coal choice exception in EPA Base Case.	
Mercer	New Jersey	Unit 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/12	Install SCR (or approved tech) and continually operate	0.1	01/01/07		0.015	12/31/10				The settlement requires coal with monthly average sulfur content no greater than 2% at units operating FGD -- this limit is modeled as a coal choice exception in EPA Base Case.	
TECO																		
Big Bend	Florida	Unit 1			Existing Scrubber (shared by Units 1 & 2)	95% (95% or .25)	09/1/00 (01/01/13)	Install SCR	0.1	05/01/09				The provision did not specify an amount of SO_2 allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.				http://www2.epa.gov/enforcement/tampa-electric-company-teco-clean-air-act-caa-settlement
Big Bend	Florida	Unit 2			Existing Scrubber (shared by Units 1 & 2)	95% (95% or .25)	09/1/00 (01/01/13)	Install SCR	0.1	05/01/09								
Big Bend	Florida	Unit 3			Existing Scrubber (shared by Units 3 & 4)	93% if Units 3 & 4 are operating	2000 (01/01/10)	Install SCR	0.1	05/01/09								
Big Bend	Florida	Unit 4			Existing Scrubber (shared by Units 3 & 4)	93% if Units 3 & 4 are operating	06/22/05	Install SCR	0.1	07/01/07								
Gannon	Florida	Six units	Retire all six coal units and repower at least 550 MW of coal capacity to natural gas	12/31/04														
WEPCO																		
			WEPCO shall comply with the following system wide average NO_x emission rates and total NO_x tonnage permissible: by 1/1/2005 an emission rate of 0.27 and 31,500 tons, by 1/1/2007 an emission rate of 0.19 and 23,400 tons, and by 1/1/2013 an emission rate of 0.17 and 17, 400 tons. For SO_2 emissions, WEPCO will comply with: by 1/1/2005 an emission rate of 0.76 and 86,900 tons, by 1/1/2007 an emission rate of 0.61 and 74,400 tons, by 1/1/2008 an emission rate of 0.45 and 55,400 tons, and by 1/1/2013 an emission rate of 0.32 and 33,300 tons.															http://www2.epa.gov/enforcement/wisconsin-electric-power-company-wepco-clean-air-act-civil-settlement
Presque Isle	Wisconsin	Units 1 – 4	Retire or install SO_2 and NO_x controls	12/31/12	Install and continuously operate FGD (or approved equiv. tech)	95% or 0.1	12/31/12	Install SCR (or approved tech) and continually operate	0.1	12/31/12				The provision did not specify an amount of SO_2 allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.				
Presque Isle	Wisconsin	Units 5, 6						Install and operate low NO_x burners		12/31/03								
Presque Isle	Wisconsin	Units 7, 8						Operate existing low NO_x burners		12/31/05	Install Baghouse							
Presque Isle	Wisconsin	Unit 9						Operate existing low NO_x burners		12/31/06	Install Baghouse							
Pleasant Prairie	Wisconsin	Unit 1			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/06	Install and continuously operate SCR (or approved tech)	0.1	12/31/06								

Company and Plant	State	Unit	Settlement Actions: Retire/Repower: Action	Retire/Repower: Effective Date	SO_2 control: Equipment	SO_2 control: Percent Removal or Rate	SO_2 control: Effective Date	NO_x Control: Equipment	NO_x Control: Rate	NO_x Control: Effective Date	PM or Mercury Control: Equipment	PM or Mercury Control: Rate	PM or Mercury Control: Effective Date	Allowance Retirement: Retirement	Allowance Restriction: Restriction	Effective Date	Notes	Reference
	Wisconsin	Unit 2			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/07	Install and continuously operate SCR (or approved tech)	0.1	12/31/03								
Oak Creek	Wisconsin	Units 5, 6			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/12	Install and continuously operate SCR (or approved tech)	0.1	12/31/12								
	Wisconsin	Unit 7			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/12	Install and continuously operate SCR (or approved tech)	0.1	12/31/12								
	Wisconsin	Unit 8			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/12	Install and continuously operate SCR (or approved tech)	0.1	12/31/12								
Port Washington	Wisconsin	Units 1 – 4	Retire	12/31/04 for Units 1 – 3. Unit 4 by entry of consent decree														
Valley	Wisconsin	Boilers 1 – 4						Operate existing low NO_x burner		30 days after entry of consent decree								
VEPCO																		
			The Total Permissible NO_x Emissions (in tons) from VEPCO system are: 104,000 in 2003, 95,000 in 2004, 90,000 in 2005, 83,000 in 2006, 81,000 in 2007, 63,000 in 2008 – 2010, 54,000 in 2011, 50,000 in 2012, and 30,250 each year thereafter. Beginning 1/1/2013 they will have a system wide emission rate no greater than 0.15 lbs/mmBTU.															
Mount Storm	West Virginia	Units 1 – 3			Construct or improve FGD	95% or 0.15	01/01/05	Install and continuously operate SCR	0.11	01/01/08				On or before March 31 of every year beginning in 2013 and continuing thereafter, VEPCO shall surrender 45,000 SO_2 allowances.				http://www2.epa.gov/enforcement/virginia-electric-and-power-company-vepco-clean-air-act-caa-settlement
Chesterfield	Virginia	Unit 4						Install and continuously operate SCR	0.1	01/01/13								
	Virginia	Unit 5			Construct or improve FGD	95% or 0.13	10/12/12	Install and continuously operate SCR	0.1	01/01/12								
	Virginia	Unit 6			Construct or improve FGD	95% or 0.13	01/01/10	Install and continuously operate SCR	0.1	01/01/11								
Chesapeake Energy	Virginia	Units 3, 4						Install and continuously operate SCR	0.1	01/01/13								
Clover	Virginia	Units 1, 2			Improve FGD	95% or 0.13	09/01/03											
Possum Point	Virginia	Units 3, 4	Retire and repower to natural gas	05/02/03														
Santee Cooper																		
			Santee Cooper shall comply with the following system wide averages for NO_x emission rates and combined tons for emission of: by 1/01/2005 facility shall comply with an emission rate of 0.3 and 30,000 tons, by 1/1/2007 an emission rate of 0.18 and 25,000 tons, by 1/1/2010 and emission rate of 0.15 and 20,000 tons. For SO_2 emission the company shall comply with system wide averages of: by 1/1/2005 an emission rate of 0.92 and 95,000 tons, by 1/1/2007 and emission rate of 0.75 and 85,000 tons, by 1/1/2009 an emission rate of 0.53 and 70 tons, and by 1/1/2011 and emission rate of 0.5 and 65 tons.															http://www2.epa.gov/enforcement/south-carolina-public-service-
Cross	South Carolina	Unit 1			Upgrade and continuously operate FGD	95%	06/30/06	Install and continuously operate SCR	0.1	05/31/04				The provision did not specify an amount of SO_2 allowances to be				

Company and Plant	State	Unit	Settlement Actions: Retire/Repower: Action	Retire/Repower: Effective Date	SO_2 control: Equipment	SO_2 control: Percent Removal or Rate	SO_2 control: Effective Date	NO_x Control: Equipment	NO_x Control: Rate	NO_x Control: Effective Date	PM or Mercury Control: Equipment	PM or Mercury Control: Rate	PM or Mercury Control: Effective Date	Allowance Retirement: Retirement	Allowance Restriction: Restriction	Effective Date	Notes	Reference
	South Carolina	Unit 2			Upgrade and continuously operate FGD	87%	06/30/06	Install and continuously operate SCR	0.11/0.1	05/31/04 and 05/31/07				surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.				authority-santee-cooper-settlement
Winyah	South Carolina	Unit 1			Install and continuously operate FGD	95%	12/31/08	Install and continuously operate SCR	0.11/0.1	11/30/04 and 11/30/04								
	South Carolina	Unit 2			Install and continuously operate FGD	95%	12/31/08	Install and continuously operate SCR	0.12	11/30/04								
	South Carolina	Unit 3			Upgrade and continuously operate existing FGD	90%	12/31/08	Install and continuously operate SCR	0.14/0.12	11/30/2005 and 11/30/08								
	South Carolina	Unit 4			Upgrade and continuously operate existing FGD	90%	12/31/07	Install and continuously operate SCR	0.13/0.12	11/30/05 and 11/30/08								
Grainger	South Carolina	Unit 1						Operate low NO_x burner or more stringent technology		06/25/04								
	South Carolina	Unit 2						Operate low NO_x burner or more stringent technology		05/01/04								
Jeffries	South Carolina	Units 3, 4						Operate low NO_x burner or more stringent technology		06/25/04								
OHIO EDISON																		
			Ohio Edison shall achieve reductions of 2,483 tons NO_x between 7/1/2005 and 12/31/2010 using any combination of: 1) low sulfur coal at Burger Units 4 and 5, 2) operating SCRs currently installed at Mansfield Units 1 – 3 during the months of October through April, and/or 3) emitting fewer tons than the Plant-Wide Annual Cap for NO_x required for the Sammis Plant. Ohio Edison must reduce 24,600 tons system-wide of SO_2 by 12/31/2010.															
			No later than 8/11/2005, Ohio Edison shall install and operate low NO_x burners on Sammis Units 1, 2,4,5,6, and 7 and overfired air on Sammis Units 1,2,3,6, and 7. No later than 12/1/2005, Ohio Edison shall install advanced combustion control optimization with software to minimize NO_x emissions from Sammis Units 1 – 5.															
W.H. Sammis Plant	Ohio	Unit 1			Install Induct Scrubber (or approved equiv. control tech)	50% removal or 1.1 lbs/mmBTU	12/31/08	Install SNCR (or approved alt. tech) & operate continuously	0.25	10/31/07				Beginning on 1/1/2006, Ohio Edison may use, sell or transfer any restricted SO_2 only to satisfy the Operational Needs at the Sammis, Burger and Mansfield Plant, or new units within the FirstEnergy System that comply with a 96% removal for SO_2. For calendar year 2006 through 2017, Ohio Edison may accumulate SO_2 allowances for use at the Sammis, Burger, and Mansfield plants, or FirstEnergy units equipped with SO_2 Emission Control Standards. Beginning in 2018, Ohio Edison shall surrender unused restricted SO_2			Plant-wide NOx Annual Caps: 11,371 tons 7/1/2005 – 12/31/2005; 21,251 tons 2006; 20,596 tons 2007; 18,903 tons 2008; 17,328 tons 2009 – 2010; 14,845 tons 2011; 11,863 2012 onward. Sammis Plant-Wide Annual SO_2 Caps: 58,000 tons SO_2 7/1/2005-12/31/2005; 116,000 tons 1/1/2006 – 12/31/2007; 114,000 tons 1/1/2008-12/31/2008; 101,500 tons 1/1/2009 – 12/31/2010; 29,900 tons 1/1/2011 onward. Sammis Units 1 – 5 are also subject to the following SO_2 Monthly Caps if Ohio Edison installs the improved SO_2 control technology (Unit 5's option A): 3,242 tons May, July, and August 2010; 3,137 tons June and September 2010. Ohio Edison has installed the required SO_2 technology (Unit 5's option B), so the Monthly Caps are: 2,533 tons May, July, and August 2010; 2,451 tons June and September 2010. Add'l Monthly Caps are: 2,533 tons May, July, and August 2011; 2,451 tons June and September 2011 thereafter.	http://www2.epa.gov/enforcement/ohio-edison-company-wh-sammis-power-station-clean-air-act-2005-settlement-and-2009
	Ohio	Unit 2			Install Induct Scrubber (or approved equiv. control tech)	50% removal or 1.1 lbs/mmBTU	12/31/08	Operate existing SNCR continuously	0.25	02/15/06								
	Ohio	Unit 3			Install Induct Scrubber (or approved equiv. control tech)	50% removal or 1.1 lbs/mmBTU	12/31/08	Operate low NO_x burners and overfire air by 12/1/05; install SNCR (or approved alt. tech) & operate continuously by 12/31/07	0.25	12/01/05 and 10/31/07								
	Ohio	Unit 4			Install Induct Scrubber (or approved equiv. control tech)	50% removal or 1.1 lbs/mmBTU	06/30/09	Install SNCR (or approved alt. tech) & operate continuously	0.25	10/31/07								

Company and Plant	State	Unit	Settlement Actions														Notes	Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date		
	Ohio	Unit 5			Install Flash Dryer Absorber or ECO_2 (or approved equiv. control tech) & operate continuously	50% removal or 1.1 lbs/mmBTU	06/29/09	Install SNCR (or approved alt. tech) & Operate Continuously	0.29	03/31/08				allowances.				
	Ohio	Unit 6			Install FGD[3] (or approved equiv. control tech) & operate continuously	95% removal or 0.13 lbs/mmBTU	06/30/11	Install SNCR (or approved alt. tech) & operate continuously	"Minimum Extent Practicable"	06/30/05	Operate Existing ESP Continuously	0.03	01/01/10				In addition to SNCR, settlement requires installation of first SCR (or approved alt tech) on either Unit 6 or 7 by 12/31/2010; second installation by 12/31/2011. Both SCRs must achieve 90% Design Removal Efficiency by 180 days after installation date. Each SCR must provide a 30-Day Rolling average. NO_x Emission Rate of 0.1 lbs/mmBTU starting 180 days after installation dates above.	
	Ohio	Unit 7			Install FGD (or approved equiv. control tech) & operate continuously	95% removal or 0.13 lbs/mmBTU	06/30/11	Operate existing SNCR Continuously	"Minimum Extent Practicable"	08/11/05	Operate Existing ESP Continuously	0.03	01/01/10					
Mansfield Plant	Pennsylvania	Unit 1			Upgrade existing FGD	95%	12/31/05										Additional Mansfield Plant-wide SO_2 reductions are as follows: 4,000 tons in 2006, 8,000 tons in 2007, and 12,000 tons/yr for every year after. Settlement allows relinquishment of SO_2 requirement upon shutdown of unit, after which the SO_2 reductions must be made by another plant(s).	
	Pennsylvania	Unit 2			Upgrade existing FGD	95%	12/31/06											
	Pennsylvania	Unit 3			Upgrade existing FGD	95%	10/31/07											
Eastlake	Ohio	Unit 5						Install low NO_x burners, over-fired air and SNCR & operate continuously	"Minimize Emissions to the Extent Practicable"	12/31/06							Settlement requires Eastlake Plant to achieve additional reductions of 11,000 tons of NO_x per year commencing in calendar year 2007, and no less than 10,000 tons must come from this unit. The extra 1,000 tons may come from this unit or another unit in the region. Upon shutdown of Eastlake, another plant must achieve these reductions.	
Burger	Ohio	Unit 4	Repower with at least 80% biomass fuel, up to 20% low sulfur coal OR Retire by 12/31/2010	12/31/11														
	Ohio	Unit 5		12/31/11														
MIRANT[1,6]																		
			System-wide NO_x Emission Annual Caps: 36,500 tons 2004; 33,840 tons 2005; 33,090 tons 2006; 28,920 tons 2007; 22,000 tons 2008; 19,650 tons 2009; 16,000 tons 2010 onward. System-wide NO_x Emission Ozone Season Caps: 14,700 tons 2004; 13,340 tons 2005; 12,590 tons 2006; 10,190 tons 2007; 6,150 tons 2008 – 2009; 5,200 tons 2010 thereafter. Beginning on 5/1/2008, and continuing for each and every Ozone Season thereafter, the Mirant System shall not exceed a System-wide Ozone Season Emission Rate of 0.150 lbs/mmBTU NO_x.															
Potomac River Plant	Virginia	Unit 1																
	Virginia	Unit 2																http://www2.epa.gov/enforcement/mirant-clean-air-settlement
	Virginia	Unit 3						Install low NO_x burners (or more effective tech) & operate continuously		05/01/04							Settlement requires installation of Separated Overfire Air tech (or more effective technology) by 5/1/2005. Plant-wide Ozone Season NO_x Caps: 1,750 tons 2004; 1,625 tons 2005; 1,600 tons 2006 – 2009; 1,475 tons 2010 thereafter. Plant-wide annual NO_x Caps are 3,700 tons in 2005 and each year thereafter.	
	Virginia	Unit 4						Install low NO_x burners (or more effective tech) & operate continuously		05/01/04								

Company and Plant	State	Unit	Settlement Actions: Retire/Repower: Action	Retire/Repower: Effective Date	SO_2 control: Equipment	SO_2 control: Percent Removal or Rate	SO_2 control: Effective Date	NO_x Control: Equipment	NO_x Control: Rate	NO_x Control: Effective Date	PM or Mercury Control: Equipment	PM or Mercury Control: Rate	PM or Mercury Control: Effective Date	Allowance Retirement: Retirement	Allowance Restriction: Restriction	Allowance Restriction: Effective Date	Notes	Reference
	Virginia	Unit 5						Install low NO_x burners (or more effective tech) & operate continuously		05/01/04								
Morgantown Plant	Maryland	Unit 1						Install SCR (or approved alt. tech) & operate continuously	0.1	05/01/07								
	Maryland	Unit 2						Install SCR (or approved alt. tech) & operate continuously	0.1	05/01/08								
Chalk Point	Maryland	Unit 1			Install and continuously operate FGD (or equiv. technology)	95%	06/01/10							For each year after Mirant commences FGD operation at Chalk Point, Mirant shall surrender the number of SO_2 Allowances equal to the amount by which the SO_2 Allowances allocated to the Units at the Chalk Point Plant are greater than the total amount of SO_2 emissions allowed under this Section XVIII.			Mirant must install and operate FGD by 6/1/2010 if authorized by court to reject ownership interest in Morgantown Plant, or by no later than 36 months after they lose ownership interest of the Morgantown Plant. [Installed]	
	Maryland	Unit 2			Install and continuously operate FGD (or equiv. technology)	95%	06/01/10											
ILLINOIS POWER																		
			System-wide NO_x Emission Annual Caps: 15,000 tons 2005; 14,000 tons 2006; 13,800 tons 2007 onward. System-wide SO_2 Emission Annual Caps: 66,300 tons 2005 – 2006; 65,000 tons 2007; 62,000 tons 2008 – 2010; 57,000 tons 2011; 49,500 tons 2012; 29,000 tons 2013 onward.															http://www2.epa.gov/enforcement/illinois-power-company-and-dynegy-midwest-generation-settlement
Baldwin	Illinois	Unit 1			Install wet or dry FGD (or approved equiv. alt. tech) & operate continuously	0.1	12/31/11	Operate OFA & existing SCR continuously	0.1	08/11/05	Install & continuously operate Baghouse	0.015	12/31/10	By year end 2008, Dynegy will surrender 12,000 SO_2 emission allowances, by year end 2009 it will surrender 18,000, by year end 2010 it will surrender 24,000, any by year end 2011 and each year thereafter it will surrender 30,000 allowances. If the surrendered allowances result in insufficient remaining allowances allocated to the units comprising the DMG system, DMG can request to surrender fewer SO_2 allowances.				
	Illinois	Unit 2			Install wet or dry FGD (or approved equiv. alt. tech) & operate continuously	0.1	12/31/11	Operate OFA & existing SCR continuously	0.1	08/11/05	Install & continuously operate Baghouse	0.015	12/31/10					
	Illinois	Unit 3			Install wet or dry FGD (or approved equiv. alt. tech) & operate continuously	0.1	12/31/11	Operate OFA and/or low NO_x burners	0.12 until 12/30/12; 0.1 from 12/31/12	08/11/05 and 12/31/12	Install & continuously operate Baghouse	0.015	12/31/10					
Havana	Illinois	Unit 6			Install wet or dry FGD (or approved equiv. alt. tech) & operate continuously	1.2 lbs/mmBTU until 12/30/2012; 0.1 lbs/mmBTU from 12/31/2012 onward	08/11/05 and 12/31/12	Operate OFA and/or low NO_x burners & operate existing SCR continuously	0.1	08/11/05	Install & continuously operate Baghouse, then install ESP or alt. PM equip	For Bag-house: .015 lbs/mmBTU; For ESP: .03 lbs/mmBTU	For Baghouse: 12/31/12; For ESP: 12/31/05					

			Settlement Actions															
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
Company and Plant	State	Unit	Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	Notes	Reference
Hennepin	Illinois	Unit 1				1.2	07/27/05	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/06				Settlement requires first installation of ESP at either Unit 1 or 2 on 12/31/2006; and on the other by 12/31/2010.	
	Illinois	Unit 2				1.2	07/27/05	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/06					
Vermilion	Illinois	Unit 1				1.2	01/31/07	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/10					
	Illinois	Unit 2				1.2	01/31/07	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/10					
Wood River	Illinois	Unit 4				1.2	07/27/05	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/05				Settlement requires first installation of ESP at either Unit 4 or 5 on 12/31/2005; and on the other by 12/31/2007.	
	Illinois	Unit 5				1.2	07/27/05	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/05					
Kentucky Utilities Company																		

			Settlement Actions															
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
Company and Plant	State	Unit	Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	Notes	Reference
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.	http://www2.epa.gov/enforcement/kentucky-utilities-company-clean-air-act-settlement
Salt River Project Agricultural Improvement and Power District (SRP)																		
Coronado Generating Station	Arizona	Unit 1 or Unit 2			Immediately begin continuous operation of existing FGDs on both units, install new FGD.	95% or 0.08	New FGD installed by 1/1/2012	Install and continuously operate low NO_x burner and SCR	0.32 prior to SCR installation, 0.080 after	LNB by 06/01/2009, SCR by 06/01/2014	Optimization and continuous operation of existing ESPs.	0.03	Optimization begins immediately, rate limit begins 01/01/12 (date of new FGD installation)	Beginning in 2012, all surplus SO_2 allowances for both Coronado and Springerville Unit 4 must be surrendered through 2020. The allowances limited by this condition may, however, be used for compliance at a prospective future plant using BACT and otherwise specified in par. 54 of the consent decree.	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 plant-wide NO_x cap is 7,300 tons after 6/1/2014.	http://www2.epa.gov/enforcement/salt-river-project-agriculture-improvement-and-power-district-settlement
	Arizona	Unit 1 or Unit 2			Install new FGD	95% or 0.08	01/01/13	Install and continuously operate low NO_x burner	0.32	06/01/11			Optimization begins immediately, rate limit begins 01/01/13 (date of new FGD installation)					
American Electric Power																		
Eastern System-Wide [Modified Limits for SO_2]						Annual Cap (tons)	Year											http://www.ct.gov/ag/lib/ag/press_releases/2013/20130225_aep_cdmod.pdf
						145,000	2016-2018											
						113,000	2019-2021											
						110,000	2022-2025											
						102,000	2026-2028											
						94,000	2029 and thereafter											
Eastern System-Wide						Annual Cap (tons)	Year		Annual Cap (tons)	Year				NO_x and SO_2 allowances that would have been made available by emission reductions pursuant to the Consent Decree must be surrendered.	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,			http://www2.epa.gov/enforcement/american-electric-power-service-corporation
						450,000	2010		96,000	2009								
						450,000	2011		92,500	2010								
						420,000	2012		92,500	2011								
						350,000	2013		85,000	2012								

Company and Plant	State	Unit	Settlement Actions: Retire/Repower: Action	Retire/Repower: Effective Date	SO_2 control: Equipment	SO_2 control: Percent Removal or Rate	SO_2 control: Effective Date	NO_x Control: Equipment	NO_x Control: Rate	NO_x Control: Effective Date	PM or Mercury Control: Equipment	PM or Mercury Control: Rate	PM or Mercury Control: Effective Date	Allowance Retirement: Retirement	Allowance Restriction: Restriction	Allowance Restriction: Effective Date	Notes	Reference
						340,000	2014		85,000	2013					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 supercompliant allowances.			
						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																
	West Virginia	Kammer 1 – 3																
Amos	West Virginia	Unit 1			Install and continuously operate FGD		12/31/09	Install and continuously operate SCR		01/01/08								-
	West Virginia	Unit 2			Install and continuously operate FGD		12/31/10	Install and continuously operate SCR		01/01/09								-
	West Virginia	Unit 3			Install and continuously operate FGD		12/31/09	Install and continuously operate SCR		01/01/08								-
Big Sandy	Kentucky	Unit 1			Burn only coal with no more than 1.75 lbs/mmBTU annual average		Date of entry	Continuously operate low NO_x burners		Date of entry								-
	Kentucky	Unit 2			Install and continuously operate FGD		12/31/15	Install and continuously operate SCR		01/01/09								-
Cardinal	Ohio	Unit 1			Install and continuously operate FGD		12/31/08	Install and continuously operate SCR		01/01/09	Continuously operate ESP	0.03	12/31/09					-
	Ohio	Unit 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					-
	Ohio	Unit 3			Install and continuously operate FGD		12/31/12	Install and continuously operate SCR		01/01/09								-
Clinch River	Virginia	Units 1 – 3				Plant-wide annual cap: 21,700 tons from 2010 to 2014, then 16,300 after 1/1/2015	2010 – 2014, 2015 and thereafter	Continuously operate low NO_x burners		Date of entry								-

			Settlement Actions															Notes	Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction				
Company and Plant	State	Unit	Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date			
Conesville	Ohio	Unit 1	Retire, retrofit, or re-power	Date of entry															-
	Ohio	Unit 2	Retire, retrofit, or re-power	Date of entry															-
	Ohio	Unit 3	Retire, retrofit, or re-power	12/31/12															-
	Ohio	Unit 4			Install and continuously operate FGD		12/31/10	Install and continuously operate SCR		12/31/10									-
	Ohio	Unit 5			Upgrade existing FGD	95%	12/31/09	Continuously operate low NO_x burners		Date of entry									-
	Ohio	Unit 6			Upgrade existing FGD	95%	12/31/09	Continuously operate low NO_x burners		Date of entry									-
Gavin	Ohio	Unit 1			Install and continuously operate FGD		Date of entry	Install and continuously operate SCR		01/01/09									-
	Ohio	Unit 2			Install and continuously operate FGD		Date of entry	Install and continuously operate SCR		01/01/09									-
Glen Lynn	Virginia	Units 1 – 3																	-
	Virginia	Units 5, 6			Burn only coal with no more than 1.75 lbs/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	01/01/10	Continuously operate over-fire air		Date of entry									-
Kanawha River	West Virginia	Units 1, 2			Burn only coal with no more than 1.75 lbs/mmBTU annual average		Date of entry	Continuously operate low NO_x burners		Date of entry									-
Mitchell	West Virginia	Unit 1			Install and continuously operate FGD		12/31/07	Install and continuously operate SCR		01/01/09									-
	West Virginia	Unit 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															-
	Ohio	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									-

Company and Plant	State	Unit	Settlement Actions: Retire/Repower: Action	Retire/Repower: Effective Date	SO_2 control: Equipment	SO_2 control: Percent Removal or Rate	SO_2 control: Effective Date	NO_x Control: Equipment	NO_x Control: Rate	NO_x Control: Effective Date	PM or Mercury Control: Equipment	PM or Mercury Control: Rate	PM or Mercury Control: Effective Date	Allowance Retirement: Retirement	Allowance Restriction: Restriction	Effective Date	Notes	Reference
Rockport			Rockport Units 1 & 2 shall not exceed an Annual Tonnage Limit of 28 MTons of SO_2 in 2016- 2017, 26 Mtons in 2018-2019, 22 MTons in 2020-2025, 18 MTons in 2026-2028 and 10 MTons in 2029 and each year thereafter.															
	Indiana	Unit 1			Install DSI __ Install and continuously operate FGD		4/16/2015 __ 12/31/2025	Install and continuously operate SCR		12/31/25								-
	Indiana	Unit 2			Install DSI __ Install and continuously operate FGD		4/16/2015 __ 12/31/2028	Install and continuously operate SCR		12/31/28								-
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 lbs/mmBTU annual average		Date of entry	Continuously operate low NO_x burners		Date of entry								-
	Indiana	Unit 4			Burn only coal with no more than 1.2% sulfur content annual average		Date of entry	Continuously operate over-fire air		Date of entry								-
East Kentucky Power Cooperative Inc.																		
Dale Plant	Kentucky	Unit 1						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		
	Kentucky	Unit 2						Install and continuously operate low NO_x burners by 10/31/2007	0.46	01/01/08								
System-wide	Kentucky		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.															http://www2.epa.gov/enforcement/east-kentucky-power-cooperative-settlement
						12-month rolling limit (tons)	Start of 12-month cycle		12-month rolling limit (tons)	Start of 12-month cycle								
					System-wide 12-month rolling tonnage limits apply	57,000	10/01/08	All units must operate low NO_x boilers	11,500	01/01/08	PM control devices must be operated continuously system-wide, ESPs must be optimized within 270 days of entry date, or EKPC may choose to submit a PM Pollution Control Upgrade Analysis.	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 may not be sold or traded. SO_2 and NO_x allowances allocated to EKPC must be used within the EKPC system. Allowances made available due to supercompliance may be sold or traded.			
						40,000	07/01/11		8,500	01/01/13								
						28,000	01/01/13		8,000	01/01/15								

			Settlement Actions															
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
Company and Plant	**State**	**Unit**	**Action**	**Effective Date**	**Equipment**	**Percent Removal or Rate**	**Effective Date**	**Equipment**	**Rate**	**Effective Date**	**Equipment**	**Rate**	**Effective Date**	**Retirement**	**Restriction**	**Effective Date**	**Notes**	**Reference**
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								
	Kentucky	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	60 days after entry								
Dale Plant	Kentucky	Unit 3	EKPC may choose to retire Dale 3 and 4 in lieu of installing controls in Cooper 2	12/31/2012														
	Kentucky	Unit 4																
Cooper	Kentucky	Unit 1																
	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		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							EKPC has installed a DFGD on this unit and Dale continues to operate.	
Nevada Power Company																		
			Beginning 1/1/2010, combined NO_x emissions from Units 5, 6, 7, and 8 must be no more than 360 tons per year.															
Clark Generating Station	Nevada	Unit 5	Units may only fire natural gas					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	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.			http://www2.epa.gov/enforcement/nevada-power-company-clean-air-act-caa-settlement
	Nevada	Unit 6							5ppm 1-hour average	12/31/09 (ULNB installation), 01/30/10 (1-hour average)								

Company and Plant	State	Unit	Settlement Actions														Notes	Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date		
	Nevada	Unit 7							5ppm 1-hour average	12/31/09 (ULNB installation), 01/30/10 (1-hour average)								
	Nevada	Unit 8							5ppm 1-hour average	12/31/08 (ULNB installation), 01/30/09 (1-hour average)								
Dayton Power & Light																		
			Non-EPA Settlement of 10/23/2008															
Stuart Generating Station	Ohio	Station-wide			Complete installation of FGDs on each unit.	96% or 0.10	07/31/09	Owners may not purchase any new catalyst with SO_2 to SO_3 conversion rate greater than 0.5%	0.17 station-wide	30 days after entry		0.030 lbs per unit	07/31/09		NO_x and SO_2 allowances may not be used to comply with the monthly rates specified in the Consent Decree.			
									0.17 station-wide	60 days after entry date								
						82% including data from periods of malfunctions	7/31/09 through 7/30/11	Install control technology on one unit	0.10 on any single unit	12/31/12		Install rigid-type electro-des in each unit's ESP	12/31/15					
						82% including data from periods of malfunctions	after 7/31/11		0.15 station-wide	07/01/12								
									0.10 station-wide	12/31/14								
PSEG FOSSIL, Amended Consent Decree of November 2006																		
Kearny	New Jersey	Unit 7	Retire unit	01/01/07										Allowances allocated to Kearny, Hudson, and Mercer may only be used for the operational needs of those units, and all surplus allowances must be surrendered. Within 90 days of amended Consent Decree, PSEG must surrender 1,230 NO_x Allowances and 8,568 SO_2 Allowances not already allocated to or generated by the units listed here. Kearny allowances must be surrendered with the shutdown of those units.				http://www2.epa.gov/enforcement/pseg-fossil-llc-settlement
	New Jersey	Unit 8	Retire unit	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					

			Settlement Actions															
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
Company and Plant	State	Unit	Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	Notes	Reference
						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	Unit 1			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					
Mercer	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	01/01/07	Install Baghouse (or approved technology)	0.015	12/31/10					
Westar Energy																		
Jeffrey Energy Center	Kansas	All units			Units 1, 2, and 3 have a total annual limit of 6,600 tons of SO_2 starting 2011 Units 1, 2, and 3 must all install FGDs by 2011 and operate them continuously. FGDs must maintain a 30-Day Rolling Average Unit Removal Efficiency for SO_2 of at least 97% or a 30-Day Rolling Average Unit Emission Rate for SO_2 of no greater than 0.070 lbs/mmBTU.			Units 1-3 must continuously operate Low NO_x Combustion Systems by 2012 and achieve and maintain a 30-Day Rolling Average Unit Emission Rate for NO_x of no greater than 0.180 lbs/mmBTU. One of the three units must install an SCR by 2015 and operate it continuously to maintain a 30-Day Rolling Average Unit Emission Rate for NO_x of no greater than 0.080 lbs/mmBTU. By 2013 Westar shall elect to either (a) install a second SCR on one of the other JEC Units by 2017 or (b) meet a 0.100 lbs/mmBTU Plant-Wide 12-Month Rolling Average Emission Rate for NO_x by 2015			Units 1, 2, and 3 must operate each ESP and FGD system continuously by 2011 and maintain a 0.030 lbs/mmBTU PM Emissions Rate. Units 1 and 2's ESPs must be rebuilt by 2014 in order to meet a 0.030 lbs/mmBTU PM Emissions Rate							http://www2.epa.gov/enforcement/westar-energy-inc-settlement
Duke Energy																		
Gallagher	Indiana	Units 1 & 3	Retire or repower as natural gas	1/1/2012														http://www2.epa.gov/enforcement/duke-energy-gallagher-plant-clean-air-act-settlement
Gallagher	Indiana	Units 2 & 4			Install Dry sorbent injection technology	80%	1/1/2012											
American Municipal Power																		
Gorsuch Station	Ohio	Units 2 & 3	Elected to Retire Dec 15, 2010 (must retire by Dec 31, 2012)															http://www2.epa.gov/enforcement/american-municipal-power-clean-air-act-settlement
Gorsuch Station	Ohio	Units 1 & 4																
Hoosier Energy Rural Electric Cooperative																		
Ratts	Indiana	Units 1 & 2						Install & continually operate SNCRS	0.25	12/31/2011	Continuously operate ESP			Annually surrender any NO_x and SO_2 allowances that Hoosier does not need in order to meet its regulatory obligations				http://www2.epa.gov/enforcement/hoo

			Settlement Actions															
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
Company and Plant	State	Unit	Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	Notes	Reference
Merom	Indiana	Unit 1			Continuously run current FGD for 90% removal and update FGD for 98% removal by 2012	98%	2012	Continuously operate existing SCRs	0.12		Continuously operate ESP and achieve PM rate no greater than 0.007 by 6/1/12							sier-energy-rural-electric-cooperative-inc-settlement
		Unit 2			Continuously run current FGD for 90% removal and update FGD for 98% removal by 2014	98%	2014				Continuously operate ESP and achieve PM rate no greater than 0.007 by 6/1/13							
Northern Indiana Public Service Co.																		
Bailly	Indiana	Units 7 & 8			Upgrade existing FGD	95% by 01/01/11 97% by 01/01/14 (95% if low sulfur coal only is burned)		OFA & SCR	0.15 lbs/mmBTU by 12/31/10 0.13 lbs/mmBTU by 12/31/13 0.12 lbs/mmBTU by 12/31/15			0.3 lbs/mmBTU (0.015 if a Baghouse is installed)	12/31/2010					http://www2.epa.gov/enforcement/northern-indiana-public-service-company-clean-air-act-settlement
Michigan City	Indiana	Unit 12			FGD	0.1 lbs/mmBTU	12/31/2018	OFA & SCR	0.14 lbs/mmBTU by 12/31/10 0.12 lbs/mmBTU by 12/31/11 0.10 lbs/mmBTU by 12/31/13			0.3 lbs/mmBTU (0.015 if a Baghouse is installed)	12/31/2018					
Schahfer	Indiana	Unit 14			FGD	0.08 lbs/mmBTU	12/31/2013	OFA & SCR	0.14 lbs/mmBTU by 12/31/10 0.12 lbs/mmBTU by 12/31/12 0.10 lbs/mmBTU by 12/31/14			0.3 lbs/mmBTU (0.015 if a baghouse is installed)	12/31/2013					
	Indiana	Unit 15			FGD	0.08 lbs/mmBTU	12/31/2015	LNB/OFA	0.16	3/31/2011		0.3 lbs/mmBTU (0.015 if a baghouse is installed)	12/31/2015					
								Either: SCR or SNCR	0.08	12/31/2015								
									0.15	12/31/2012								
	Indiana	Units 17 & 18			Upgrade existing FGD	97%	1/31/2011	LNB/OFA	0.2	3/31/2011		0.3 lbs/mmBTU (0.015 if a baghouse is installed)	12/31/2010					
Dean H Mitchell	Indiana	Units 4, 5, 6, & 11	Retire	12/31/2010														
Tennessee Valley Authority																		
Colbert	Alabama	Units 1-4			FGD		6/30/2016	SCR		6/30/2016				Shall surrender all calendar year NO_x and SO_2 Allowances allocated to TVA that are not needed for compliance with its own CAA reqts. Allocated allowances may be used for TVA's own compliance with CAA reqts.	Shall not use NO_x or SO_2 Allowances to comply with any requirement of the Consent Decree, Nothing prevents TVA from purchasing or otherwise obtaining NO_x and SO_2 allowances from other sources for its compliance with CAA reqts. TVA may sell, bank, use, trade, or transfer	2011		http://www2.epa.gov/enforcement/tennessee-valley-authority-clean-air-act-settlementl
		Unit 5			FGD		12/31/15	SCR		Effective Date								
Widows Creek	Alabama	Units 1 - 6	Retire 2 units 7/31/13 Retire 2 units 7/31/14 Retire 2 units 7/31/15															
		Unit 7						SCR		Effective Date								
		Unit 8						SCR		Effective Date								
Paradise	Kentucky	Units 1 & 2			Upgrade FGD	93%	12/31/12	SCR		Effective Date								
		Unit 3			Wet FGD		Effective Date	SCR		Effective Date								

Company and Plant	State	Unit	Settlement Actions															Notes	Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date		
Shawnee	Kentucky	Units 1 & 4			FGD	1.2	12/31/17	SCR		12/31/17					any NO_x and SO_2 Super-Compliance" Allowances resulting from meeting System-wide limits. Except that reductions used to support new CC/CT will not be Super Allowances in that year and thereafter.			
		Units 5 - 10				1.2	Effective Date											
Allen	Tennessee	Units 1 - 3			FGD		12/31/18					0.3	12/31/18					
Bull Run	Tennessee	Unit 1			Wet FGD		Effective Date					0.3	Effective Date					
Cumberland	Tennessee	Units 1 & 2			Wet FGD		Effective Date											
Gallatin	Tennessee	Units 1 - 4			FGD		12/31/17	SCR		12/31/17		0.3	12/31/17					
John Sevier	Tennessee	Units 1 & 2	Retire 2 Units 12/31/12 and 12/31/15															
		Units 3 & 4			FGD		12/31/15	SCR		12/31/15								
Johnsonville	Tennessee	Units 1 - 10	Retire 6 Units 12/31/15 Retire 4 Units 12/31/17															
Kingston	Tennessee	Units 1 - 9			FGD		Effective Date	SCR		Effective Date		0.3	Effective Date					
Wisconsin Public Service																		
Pulliam	Wisconsin	Units 5-6	Retire, refuel or repower as natural gas	6/1/2015		0.750 lbs/mmBTU	1/1/2013 until retirement											http://www2.epa.gov/enforcement/wisconsin-public-service-corporation-settlement
	Wisconsin	Units 7-8				0.750 lbs/mmBTU & plant-wide cap of 2100 tons starting 2016	1/1/2013		0.250 lbs/mmBTU & plant-wide cap of 1500 tons starting 2016	12/31/12							The modeled SO_2 rate in IPM is lower; only tonnage limitation imposed through a constraint.	
Weston	Wisconsin	Unit 1				0.750 lbs/mmBTU	1/1/2013 until retirement		0.250 lbs/mmBTU	12/31/2012 until retirement								
	Wisconsin	Units 2	Retire, refuel or repower as natural gas	6/1/2015		0.750 lbs/mmBTU	1/1/2013 until retirement		0.280 lbs/mmBTU	12/31/2012 until retirement								
	Wisconsin	Units 3			ReACT by 12/31/2016	0.750 lbs/mmBTU until 2016 0.080 lbs/mmBTU 2016 onwards	12/31/16	ReACT by 12/31/2016	0.130 lbs/mmBTU until 2016 0.100 lbs/mmBTU 2016 onwards	12/31/16								
	Wisconsin	Units 4			Continuously Operate the existing DFGD & burn only Powder River Basin Coal	0.080 lbs/mmBTU	2/31/2013	Continuously Operate the existing SCR	0.060 lbs/mmBTU	2/31/2013								
Louisiana Generating LLC																		
			Plant-Wide Annual Tonnage Limitations for SO_2 is 18,950 tons in					Plant-Wide Annual Tonnage Limitations										

Company and Plant	State	Unit	Settlement Actions: Retire/Repower: Action	Retire/Repower: Effective Date	SO_2 control: Equipment	SO_2 control: Percent Removal or Rate	SO_2 control: Effective Date	NO_x Control: Equipment	NO_x Control: Rate	NO_x Control: Effective Date	PM or Mercury Control: Equipment	PM or Mercury Control: Rate	PM or Mercury Control: Effective Date	Allowance Retirement: Retirement	Allowance Restriction: Restriction	Effective Date	Notes	Reference
					2016 and thereafter			for NO_x is 8,950 tons in 2015 and thereafter										
Big Cajun 2	Louisiana	Unit 1	Retirement, Refueling, Repowering, or Retrofit	04/01/25	install and Continuously Operate DSI — install and Continuously Operate Dry FGD	0.380 lbs/mmBTU [2015] — 0.070 lbs/mmBTU	4/15/2015 [DSI] — 4/1/2025 [DFGD]	install and Continuously Operate SNCR	0.150 lbs/mmBTU	05/01/14	Continuously Operate each ESP	0.030 lbs/mmBTU	04/15/15				May trade Super-Compliant Allowances, may buy external allowances to comply. "Commencing January 1, 2013, and continuing thereafter, Settling Defendant shall burn only coal with no greater sulfur content than 0.45 percent by weight on a dry basis at Big Cajun II Units 1 and 3. "	http://www2.epa.gov/enforcement/louisiana-generating-settlement
		Unit 2	Refuel/convert to NG fired	04/15/15				install and Continuously Operate SNCR	0.150 lbs/mmBTU	05/01/14								
		Unit 3						install and Continuously Operate SNCR	0.135 lbs/mmBTU	05/01/14	Continuously Operate each ESP	0.030 lbs/mmBTU	04/15/15					
Dairyland Power Cooperative																		
Dairyland Power Cooperative shall not exceed an Annual Plant-wide Tonnage Limitation of 6800 tons of NO_x in calendar years 2016, 3700 tons 2017-2019, and 3200 tons in 2020 and thereafter; and an Annual Plant-wide Tonnage Limitation of 6070 tons of SO_2 in 2016, 6060 tons 2017-2019 and 4580 tons in 2020 and thereafter.																		
Alma	Wisconsin	Unit 1	Cease Burning Coal	06/30/12														http://www2.epa.gov/enforcement/dairyland-power-cooperative-settlement
		Unit 2	Cease Burning Coal	06/30/12														
		Unit 3	Cease Burning Coal	06/30/12														
		Unit 4	**Option 2**: Retrofit and Regulate both units more stringently	12/31/14	Install and continuously operate DFGD or DSI at Alma 4	1.00 lbs/mmBTU at Alma 4 And a joint cap of 3,737 tons until 2019, and 2,242 tons thereafter. In the event that one retires, Tonnage Cap of 2,136 tons for the remaining unit until 2019 and 1,282 tons thereafter	12/31/2014	Continuously Operate the existing Low NO_x Combustion System (including OFA) and SNCR	0.350 lbs/mmBTU — Joint cap of 1308 tons for- until 2019, and 785 tons thereafter. In the event that one retires, Tonnage Cap of 746 tons for remaining unit until 2019 and 449 tons thereafter	8/1/2012 — 12/31/2014	Continuously Operate an ESP or FF on Alma Unit 4	0.030 lbs/mmBTU [with ESP] 0.015 lbs/mmBTU [with FF] at Alma 4. Joint cap of 112 tons until 2019, and 67 tons thereafter. In the event that one retires, Tonnage Cap of 64 tons for the remaining unit until 2019 and 39 tons thereafter	12/31/14				Dairyland was provided with two options for compliance. It chose Option 2 and it is the one modeled in IPM. Details on Option 1 can be found in the settlement document referenced in the adjoining column.	
		Unit 5																
J.P. Madgett	Wisconsin	Unit 1			Install and continuously operate DFGD	0.090 lbs/mmBTU	12/31/14	Continuously Operate existing Low NO_x Combustion System — Install an SCR	0.30 lbs/mmBTU — 0.080 lbs/mmBTU	8/1/2012 — 6/30/2016	Continuously Operate the existing Baghouse	0.0150 lbs/mmBTU	07/01/13					

Company and Plant	State	Unit	Settlement Actions															Notes	Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date		
Genoa	Wisconsin	Unit 1			Continuously Operate the FGD	0.090 lbs/mmBTU	12/31/12	Continuously Operate existing Low NO_x Combustion System including OFA — Install an SNCR	0.14 lbs/mmBTU — Annual Tonnage Cap of 1,140 tons	12/31/2014 — 6/1/2015	Continuously Operate the existing Baghouse	0.0150 lbs/mmBTU	07/01/13					
Dominion Energy, Inc.																		
			In calendar year 2014, and in each calendar year thereafter, Kincaid shall not exceed a Plant-Wide Annual Tonnage Limitation of 3,500 tons of NO_x & 4,400 tons of SO_2, and Brayton Point shall not exceed a Plant-Wide Annual Tonnage Limitation of 4,600 tons of NO_x & 4,100 tons of SO_2.															
Brayton Point	Massachusetts	Unit 1			Continuously Operate the existing dry FGD	0.150 lbs/mmBTU	06/01/13	Continuously Operate the SCR, OFA, and LNB	0.080 lbs/mmBTU	05/01/13	Install/Continuously Operate a Baghouse	0.015 lbs/mmBTU [PM by 2013] 0.01 lbs/mmBTU [PM post-2013]	06/01/13					http://www2.epa.gov/enforcement/dominion-energy-inc
		Unit 2						Continuously Operate the LNB and OFA	0.280 lbs/mmBTU	05/02/13								
		Unit 3			Continuously Operate dry FGD	0.080 lbs/mmBTU	07/01/13	Continuously Operate the SCR, OFA, and LNB	0.080 lbs/mmBTU	05/01/13	Install/Continuously Operate a Baghouse	0.015 lbs/mmBTU [PM by 2013] 0.01 lbs/mmBTU [PM post-2013]	07/01/13					
Kincaid Power Station	Illinois	Unit 1			Continuously Operate DSI	0.100 lbs/mmBTU	01/01/14	Continuously Operate each SCR and OFA	0.080 lbs/mmBTU	05/01/13	Continuously Operate the ESP	0.030 lbs/mmBTU [PM by 2013] 0.015 lbs/mmBTU [PM by post-2013]	06/01/13					
		Unit 2																
State Line Power Station	Indiana	Unit 3	Retire	06/01/12														
		Unit 4																
Wisconsin Power and Light																		
					Edgewater 3-5- shall not exceed an Annual Tonnage Limitation of 2,500 tons of NO_x in calendar years 2016-2018, and 1100 tons 2019 onwards & an Annual Tonnage Limitation of 12,500 tons of SO_2 in 2016, 6000 tons 2017-2018 and 1100 tons 2019 onwards. Columbia 1 & 2 shall not exceed an Annual Tonnage Limitation of 5,600 tons of NO_x in calendar years 2016-2018, and 4300 tons 2019 onwards & an Annual Tonnage Limitation of 3290 tons of SO_2 in 2016 and thereafter.													
Edgewater Generating Station	Wisconsin	Unit 3	Retire, Refuel, or Repower	12/31/15		Unit-Specific Annual Tonnage Cap of 700 Tons of SO_2	05/21/13		Unit-Specific Annual Tonnage Cap of 250 tons of NO_x	05/21/13								http://www2.epa.gov/enforcement/wisconsin-power-and-light-et-al-settlement
		Unit 4	Retire, Refuel, or Repower	12/31/18		0.700 lbs/mmBTU	05/21/13	Operate SNCR and LNB	0.150 lbs/mmBTU	01/01/14	Continuous Operation of the existing ESP	0.030 lbs/mmBTU	12/31/13					

Company and Plant	State	Unit	Settlement Actions														Notes	Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date		
		Unit 5			Install and continuously operate DFGD	0.075 lbs/mmBTU	12/31/16	Install and continuously operate SCR	0.070 lbs/mmBTU	05/01/13	Install and continuously operate Fabric Filter	0.015 lbs/mmBTU	12/31/16					
Columbia Generating Station	Wisconsin	Unit 1			Install and continuously operate DFGD	0.075 lbs/mmBTU	01/01/15	Operation of the Low NO_x Combustion System	0.150 lbs/mmBTU	07/21/13	Install and continuously operate Fabric Filter	0.015 lbs/mmBTU	12/31/14					
		Unit 2				0.075 lbs/mmBTU		Operation of the Low NO_x Combustion System — Install and continuously operate SCR	0.150 lbs/mmBTU — 0.070 lbs/mmBTU	7/21/2013 — 12/31/2018		0.015 lbs/mmBTU	12/31/14					
Nelson Dewey Generating Station	Wisconsin	Unit 1	Retire, Refuel, or Repower	12/31/15	commence burning 100% Powder River Basin or equivalent fuel containing ≤ 1.00 lbs/mmBTU of SO_2	0.800 lbs/mmBTU	05/22/13		0.300 lbs/mmBTU	04/22/13		0.100 lbs/ mmBTU	04/22/13				Cease Burning Petcoke and Commence Burning 100% PRB Coal or Equivalent at Nelson Dewey Units 1 and 2.	
		Unit 2	Retire, Refuel, or Repower	12/31/15														

Table 3-15 State Settlements in EPA Base Case v.5.13

Company and Plant	State	Unit	State Enforcement Actions: Retire/Repower: Action	Retire/Repower: Effective Date	SO_2 Control: Equipment	SO_2 Control: Percent Removal or Rate	SO_2 Control: Effective Date	NO_x Control: Equipment	NO_x Control: Rate	NO_x Control: Effective Date	PM Control: Equipment	PM Control: Rate	PM Control: Effective Date	Mercury Control: Equipment	Mercury Control: Rate	Mercury Control: Effective Date	Notes
AES																	
			If the MPC project is discontinued at Greenidge Unit 4 by 12/31/2009, Unit 4 will be subject to the following SO_2 emission caps: 2005 will be 12,125 tons, 2006 will be 11,800 tons, 2007 will be 11,475 tons, 2008 will be 11,150 tons, 2009 will be 10,825 tons. By 12/31/2009, AES shall control, repower, or cease operations at Westover Unit 7. Beginning in 2005, Unit 8 will be subject to the following SO_2 emission caps: 2005 is 9500 tons, 2006 is 9250, 2007 is 9000, 2008 is 8750, 2009 is 8500 tons.														http://www.ag.ny.gov/press-release/governor-and-attorney-general-announce-new-yorks-largest-coal-plants-slash-pollution
Greenidge	New York	Unit 4	Update: as of May 2009, CONSOL and AES describe the Greenidge Unit 4 MPC effort as a success.														http://investor.aes.com/phoenix.zhtml?c=202639&p=irol-newsArticle&ID=1274075&highlight=
Greenidge	New York	Unit 4			Install FGD	90%	09/01/07	Install SCR	0.15	09/01/07							1) Except when Greenidge Unit 4 is operating below minimum operating load, it will make good faith efforts to achieve a NO_x emission rate of 0.1 lbs/mmBtu. If this level cannot be achieved, the emission limit shall be the level achieved within one year of commencement of operation, no less stringent than 0.15 lbs/mmBtu. 2) Unit 4 will make good faith efforts to achieve a SO_2 removal efficiency of 95%. If this removal efficiency cannot be achieved, the emission limit shall be the level achieved by 9/1/2007, but no less stringent than 90% removal efficiency, resulting in a 0.38 lbs/mmBtu permitted limit.
Greenidge	New York	Unit 3	Install BACT, repower, or cease operations		Install BACT		12/31/09	Install BACT		12/31/09							
Westover			Update: as of May 2009, NO_x emissions appear to be above the specified 0.15 lbs/mmBtu														http://www.powermag.com/print/environmental/Apply-the-fundamentals-to-improve-emissions-performance_574.html
Westover	New York	Unit 8				90%	12/31/10	Install SCR	0.15	12/31/10							1) Except when Westover Unit 8 is operating below minimum operating load, it will make good faith efforts to achieve a NO_x emission rate of 0.1lbs/mmBtu. If this level cannot be achieved, the emission limit will be the level achieved within one year of operation that is no less stringent than 0.15 lbs/mmBtu. 2) Unit 8 will make good faith efforts to achieve a SO_2 removal efficiency of 95%. If this level cannot be achieved, a removal efficiency no less than 90% will be used, resulting in a 0.34 lbs/mmBtu permit.
Westover	New York	Unit 7	Install BACT, repower, or cease operations		Install BACT		12/31/09	Install BACT		12/31/09							
Hickling	New York	Unit 1	Install BACT, repower, or cease operations		Install BACT		05/01/07	Install BACT		05/01/07							
Hickling	New York	Unit 2	Install BACT, repower, or cease operations		Install BACT		05/01/07	Install BACT		05/01/07							
Jennison	New York	Unit 1	Install BACT, repower, or cease		Install BACT		05/01/07	Install BACT		05/01/07							

Company and Plant	State	Unit	State Enforcement Actions: Retire/Repower: Action	Effective Date	SO_2 Control: Equipment	Percent Removal or Rate	Effective Date	NO_x Control: Equipment	Rate	Effective Date	PM Control: Equipment	Rate	Effective Date	Mercury Control: Equipment	Rate	Effective Date	Notes
			operations														
	New York	Unit 2	Install BACT, repower, or cease operations		Install BACT		05/01/07	Install BACT		05/01/07							
Niagara Mohawk Power																	
			NRG shall comply with the below annual tonnage limitations for its Huntley and Dunkirk Stations: In 2005 59,537 tons of SO_2 and 10,777 tons of NO_x, in 2006 34,230 of SO_2 and 6,772 of NO_x, in 2007 30,859 of SO_2 and 6,211 of NO_x, in 2008 22,733 tons of SO_2 and 6,211 tons of NO_x, in 2009 19,444 of SO_2 and 5,388 of NO_x, in 2010 and 2011 19,444 of SO_2 and 4,861 of NO_x, in 2012 16,807 of SO_2 and 3,241 of NO_x, 2013 and 14,169 of SO_2 and 3,241 of NO_x thereafter.														http://www.ag.ny.gov/press-release/governor-and-attorney-general-announce-new-yorks-largest-coal-plants-slash-pollution
Huntley	New York	Units 63 – 66	Retire	Before 2008													
Public Service Co. of NM																	
San Juan	New Mexico	Unit 1			State-of-the-art technology	90%	10/31/08	State-of-the-art technology	0.3	10/31/08	Operate Baghouse and demister technology	0.015	12/31/09	Design activated carbon injection technology (or comparable tech)		12/31/09	All four units have installed Wet Scrubbers. Unit 1 and 4 NO_x controls [SNCR] are hardwired into EPA Base Case. http://nmsierraclub.org/sites/default/files/20055-10SanJuanfinaldecreeasentered%20%282%29.pdf
	New Mexico	Unit 2					03/31/09			03/31/09			12/31/09			12/31/09	
	New Mexico	Unit 3					04/30/08			04/30/08			04/30/08			04/30/08	
	New Mexico	Unit 4					10/31/07			10/31/07			10/31/07			10/31/07	
Public Service Co of Colorado																	
Comanche	Colorado	Unit 1			Install and operate FGD	0.1 lbs/mmBtu combined average	07/01/09	Install low-NO_x emission controls	0.15 lbs/mmBtu combined average	07/01/09				Install sorbent injection technology		07/01/09	Comanche units 1 and 2 taken together shall not exceed a 0.15 heat rate for NO_x, nor 0.10 for SO_2, no later than 180 days after initial start-up of control equipment, or by 7/01/2009, whichever is earlier. http://content.sierraclub.org/coal/sites/content.sierraclub.org.coal/files/elp/docs/co-comanche_agree-sign_2004-12-02.pdf
	Colorado	Unit 2			Install and operate FGD		07/01/09	Install low-NO_x emission controls		07/01/09				Install sorbent injection technology		07/01/09	
	Colorado	Unit 3			Install and operate FGD	0.1 lbs/mmBtu		Install and operate SCR	0.08		Install and operate a fabric filter dust collection system	0.013		Install sorbent injection technology		Within 180 days of start-up	
Rochester Gas & Electric																	
Russell Plant	New York	Units 1 – 4	Retire all units														http://www.ag.ny.gov/press-release/cuomo-announces-settlement-close-rochester-gas-electrics-coal-burning-russell-power
Mirant New York																	
Lovett Plant	New York	Unit 1	Retire	05/07/07													http://www.nytimes.com/2007/05/11/nyregion/11plant.html?_r=1&pagewanted=print
	New York	Unit 2	Retire	04/30/08													Retirements are pursuant to a 2003 consent decree, and the plant's failure to comply with the required reductions.
TVA																	
Allen	Tennessee	Units 1 - 3			Remove from Service, FGD, or Retire		12/31/2015	Install SCR		Effective Date							http://www2.epa.gov/sites/production/files/documents/tvacoal-fired-cd.pdf
Bull Run	Tennessee	Unit 1			Install Wet FGD		Effective Date	Install SCR		Effective Date							
Colbert	Alabama	Units 1 - 4			Remove from Service, FGD, Repower to Renewable Biomass, or Retire		6/30/2016	Remove from Service, SCR, Repower to Renewable Biomass, or Retire		6/30/2016							

Company and Plant	State	Unit	State Enforcement Actions														Notes
			Retire/Repower		SO_2 Control			NO_x Control			PM Control			Mercury Control			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	
		Unit 5			Remove from Service, FGD, or Retire		12/31/2015	Install SCR		Effective Date							
Cumberland	Tennessee	Units 1 & 2			Install Wet FGD		Effective Date	Install SCR		Effective Date							
Gallatin	Tennessee	Units 1 - 4			FGD, Repower to Renewable Biomass, or Retire		12/31/2017	Install SCR, Repower to Renewable Biomass, or Retire		12/31/2017							
John Sevier	Tennessee	Units 1 & 2	Retire	12/31/2012													
		Units 3 & 4	Remove from Service	12/31/2012	FGD, Repower to Renewable Biomass, or Retire		12/31/2015	Install SCR, Repower to Renewable Biomass, or Retire		12/31/2015							
Johnsonville	Tennessee	Units 1 - 10	Retire	6 Units by 12/31/15, 4 Units by 12/31/18													
Kingston	Tennessee	Units 1 - 9			Install Wet FGD		Effective Date	Install SCR		Effective Date							
Paradise	Kentucky	Units 1 & 2			Upgrade FGD	93% Removal	12/31/2012	Install SCR		Effective Date							
		Unit 3			Install Wet FGD		Effective Date	Install SCR		Effective Date							
Shawnee	Kentucky	Units 1 & 4			FGD, Repower to Renewable Biomass, or Retire		12/31/2017	Install SCR, Repower to Renewable Biomass, or Retire		12/31/2017							
Widows Creek	Alabama	Units 1 & 2	Retire	7/31/2013													
		Unit 3 & 4	Retire	7/31/2014													
		Units 5 & 6	Retire	7/31/2015													
		Units 7 & 8			Install Wet FGD		Effective Date	Install SCR		Effective Date							
RC Cape May Holdings, LLC																	
B L England	New Jersey	Unit 1	Retire/Repower	05/01/14													http://www.nj.gov/dep/docs/20120613104728.pdf
		Unit 2	Retire/Repower [Decision to be made by December 2013]	05/01/14													

Table 3-16 Citizen Settlements in EPA Base Case v.5.13

Company and Plant	State	Unit	Citizen Suits Provided by DOJ: Retire/Repower: Action	Retire/Repower: Effective Date	SO_2 control: Equipment	SO_2 control: Percent Removal or Rate	SO_2 control: Effective Date	NO_x Control: Equipment	NO_x Control: Rate	NO_x Control: Effective Date	PM Control: Equipment	PM Control: Rate	PM Control: Effective Date	Mercury Control: Equipment	Mercury Control: Rate	Mercury Control: Effective Date	Notes
SWEPCO (AEP)																	
Welsh	Texas	Units 1-3									Install and operate CEMs		12/31/2010				SWEPCO may attempt to demonstrate that PM CEMs are infeasible after two years of operation. http://www.ocefoundation.org/PDFs/ConsentDecree&CLtoDOJ.pdf
Allegheny Energy																	
Hatfield's Ferry	Pennsylvania	Unit 1			Install and operate wet FGD		6/30/2010				Install and operate sulfur trioxide injection systems, improve ESP performance	0.1 lbs/mmBtu in 2006, then 0.075 lbs per hour (filterable) and 0.1 lbs/mmBtu for particles less than ten microns in 2010	7/31/2006 and 6/30/2010				http://www.environmentalintegrity.org/law_library/PennFuture_EIP_Lawsuit.php
	Pennsylvania	Unit 2															
	Pennsylvania	Unit 3											11/31/2006 and 6/30/2010				
Wisconsin Public Service Corp																	
Pulliam	Wisconsin	Unit 3	Retire	12/31/2007													http://milwaukee.bizjournals.com/milwaukee/stories/2006/10/23/daily29.html
	Wisconsin	Unit 4															
University of Wisconsin																	
Charter Street Heating Plant	Wisconsin		Repower to burn 100% biomass	12/31/2012													Sierra Club suit was based on NSR. http://wisconsin.sierraclub.org/PDF/press/112607_PR_WIStateOwnedCoalSettlement.pdf
Tucson Electric Power																	
Springerville Plant	Arizona	Unit 1			Dry FGD, 85% reduction required	0.27 lbs/mmBtu	12/31/2006	SCR, LNB	0.22 lbs/mmBtu	12/31/2006	Baghouse	0.03 lbs/mmBtu	1/1/2006				Lawsuit filed by Grand Canyon Trust. Consent decree is not published. For the compliance details, see the EPA's own copy of the plant's permit revisions: http://xrl.us/springerville and http://xrl.us/springerville2
	Arizona	Unit 2															
	Arizona	Unit 3															
	Arizona	Unit 4				Four-unit cap of 10,662 tons per year once units 3 and 4 are operational			Four-unit cap of 8,940 tons per year once units 3 and 4 are operational								
Kansas City Board of Public Utilities																	
Quindaro	Kansas	Units 1	Cease burning coal/Convert to natural gas	04/16/15													http://www.bpu.com/AboutBPU/MediaNewsReleases/BPUUnifiedGovernmentSettleThreatenedLawsuit.aspx http://www.platts.com/RSSFeedDetailedNews/RSSFeed/ElectricPower/21193551 "end coal-fired operations at two coal units totaling 167 MW at its Quindaro station by April 2015 and to install a baghouse at its 232-MW Nearman-1 coal unit by September 2017." "BPU spokesman David Mehlhaff said the muni plans to convert the Quindaro-1 and -2 coal units to only natural gas firing, probably by April 2015; both units currently have dual-fuel capabilities."
	Kansas	Units 2															
Nearman	Kansas	Unit 1									Install and continuously operate a baghouse	0.01 lbs/mmBtu	09/01/17				

Company and Plant	State	Unit	Citizen Suits Provided by DOJ														Notes
			Retire/Repower		SO_2 control			NO_x Control			PM Control			Mercury Control			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	
MidAmerican Energy Company																	
Walter Scott, Jr Energy Center	Iowa	Units 1	Cease burning coal/Convert to natural gas	04/16/16													http://www.sec.gov/Archives/edgar/data/928576/000092857613000014/llcmec33113form10-q.htm "MidAmerican Energy has committed to cease burning solid fuel, such as coal, at its Walter Scott, Jr. Energy Center Units 1 and 2, George Neal Energy Center Units 1 and 2 and Riverside Energy Center by April 16, 2016...The George Neal Energy Center Unit 1 and Riverside Energy Center currently have the capability to burn natural gas in the production of electricity, although under current operating and economic conditions, production utilizing natural gas would be very limited"
	Iowa	Units 2															
George Neal Energy Center	Iowa	Units 1															
	Iowa	Units 2															
Riverside Energy Center	Iowa	Units 7															
	Iowa	Units 8															
	Iowa	Units 9															
Dominion Energy																	
Salem Harbor	Massachusetts	Unit 1-4	Retire	12/31/2011 for units 1&2 6/1/2014 for units 3&4													http://www.clf.org/wp-content/uploads/2012/02/Signed-Consent-Decree-12_11.pdf
Duke Energy																	
Wabash River	Indiana	Unit 2-5	Retire	2014													http://www.duke-energy.com/about-us/retired-coal-units-potential-retirements.asp
Wabash River	Indiana	Unit 6	Coal to Gas Conversion	6/12018													

Table 3-17 Renewable Portfolio Standards in EPA Base Case v.5.13

Regional Renewable Portfolio Standards- AEO 2013							
NEMS Region	**IPM Regions Covered**	**Units**	**2016**	**2018**	**2020**	**2025**	**2030-2050**
ERCOT (1)	ERC_REST, ERC_FRNT, ERC_GWAY, ERC_WEST	%	4.5%	4.5%	4.4%	4.4%	4.4%
MORE (3)	MIS_WUMS (42%)	%	10.1%	10.0%	10.0%	9.9%	10.0%
MROW (4)	MAP_WAUE, MIS_IA, MIS_MIDA, MIS_MNWI, MIS_MAPP, SPP_NEBR	%	8.9%	9.6%	10.3%	11.3%	11.4%
NEWE (5)	NENG_CT, NENGREST, NENG_ME	%	11.6%	13.0%	14.3%	14.5%	14.6%
NYCW (6), NYLI (7), NYUP (8)	NY_Z_J, NY_Z_K, NY_Z_C&E, NY_Z_F, NY_Z_G-I, NY_Z_A&B	%	25.0%	24.8%	24.6%	24.5%	24.6%
RFCE (9)	PJM_EMAC, PJM_PENE, PJM_SMAC, PJM_WMAC	%	9.7%	11.6%	13.6%	14.7%	14.8%
RFCM (10)	MIS_LMI	%	10.1%	10.1%	10.0%	9.9%	10.0%
RFCW (11)	MIS_INKY (90%), MIS_WUMS (58%), PJM_West, PJM_AP, PJM_ATSI, PJM_COMD	%	5.0%	6.0%	7.1%	9.2%	9.3%
SRDA (12)	S_D_AMSO, S_D_N_AR, S_D_REST, S_D_WOTA, SPP_WEST (10%)	%	0.7%	0.6%	0.6%	0.6%	0.6%
SRGW (13)	MIS_IL, MIS_MO, SPP_N (3%)	%	7.3%	10.2%	11.2%	15.7%	15.8%
SRCE (15)	S_C_KY, S_C_TVA, MIS_INKY (10%)	%	0.0%	0.0%	0.0%	0.1%	0.1%
SRVC (16)	PJM_Dom, S_VACA	%	3.3%	4.2%	5.0%	5.5%	5.5%
SPNO (17)	SPP_N (97%)	%	8.5%	9.7%	11.9%	13.1%	13.2%
SPSO (18)	SPP_SE, SPP_SPS, SPP_WEST (90%), SPP_KIAM	%	1.8%	1.9%	2.1%	2.2%	2.2%
AZNM (19)	WECC_AZ, WECC_IID, WECC_NM, WECC_SNV	%	7.4%	8.0%	9.4%	11.1%	11.1%
CAMX (20)	WEC_LADW, WEC_CALN, WEC_SDGE, WECC_SF, WECC_SCE	%	25.6%	29.3%	33.0%	32.9%	33.0%
NWPP (21)	WECC_ID, WECC_MT, WECC_NNV, WECC_PNW, WECC_UT, WECC_WY (58%)	%	7.2%	7.2%	10.1%	10.9%	11.0%
RMPA (22)	WECC_CO, WECC_WY (42%)	%	10.6%	13.1%	15.5%	15.3%	15.5%
Regional RPS Solar Carve-outs							
NEMS Region	**IPM Regions Covered**	**Units**	**2016**	**2018**	**2020**	**2025**	**2030-2050**
ERCOT (1)	ERC_REST, ERC_FRNT, ERC_GWAY, ERC_WEST	%	-	-	-	-	-
MORE (3)	MIS_WUMS (42%)	%	-	-	-	-	-
MROW (4)	MAP_WAUE, MIS_IA, MIS_MIDA, MIS_MNWI, MIS_MAPP, SPP_NEBR	%	0.01%	0.01%	0.58%	0.58%	0.59%
NEWE (5)	NENG_CT, NENGREST, NENG_ME	%	0.08%	0.08%	0.08%	0.08%	0.08%
NYCW (6), NYLI (7), NYUP (8)	NY_Z_J, NY_Z_K, NY_Z_C&E, NY_Z_F, NY_Z_G-I, NY_Z_A&B	%	0.00%	0.00%	0.00%	0.00%	0.00%

Regional Renewable Portfolio Standards- AEO 2013							
NEMS Region	**IPM Regions Covered**	**Units**	**2016**	**2018**	**2020**	**2025**	**2030-2050**
RFCE (9)	PJM_EMAC, PJM_PENE, PJM_SMAC, PJM_WMAC	%	0.30%	0.49%	0.67%	0.71%	0.71%
RFCM (10)	MIS_LMI	%	-	-	-	-	-
RFCW (11)	MIS_INKY (90%), MIS_WUMS (58%), PJM_West, PJM_AP, PJM_ATSI, PJM_COMD	%	0.18%	0.25%	0.32%	0.43%	0.45%
SRDA (12)	S_D_AMSO, S_D_N_AR, S_D_REST, S_D_WOTA, SPP_WEST (10%)	%	-	-	-	-	-
SRGW (13)	MIS_IL, MIS_MO, SPP_N (3%)	%	0.29%	0.39%	0.46%	0.68%	0.72%
SRCE (15)	S_C_KY, S_C_TVA, MIS_INKY (10%)	%	0.001%	0.001%	0.001%	0.001%	0.001%
SRVC (16)	PJM_Dom, S_VACA	%	0.06%	0.09%	0.09%	0.09%	0.09%
SPNO (17)	SPP_N (97%)	%	0.03%	0.05%	0.05%	0.08%	0.08%
SPSO (18)	SPP_SE, SPP_SPS, SPP_WEST (90%), SPP_KIAM	%	0.10%	0.10%	0.14%	0.14%	0.14%
AZNM (19)	WECC_AZ, WECC_IID, WECC_NM, WECC_SNV	%	0.48%	0.47%	0.58%	0.60%	0.61%
CAMX (20)	WEC_LADW, WEC_CALN, WEC_SDGE, WECC_SF, WECC_SCE	%	-	-	-	-	-
NWPP (21)	WECC_ID, WECC_MT, WECC_NNV, WECC_PNW, WECC_UT, WECC_WY (58%)	%	0.05%	0.05%	0.06%	0.06%	0.06%
RMPA (22)	WECC_CO, WECC_WY (42%)	%	0.01%	0.01%	0.02%	0.02%	0.02%

Table 3-18 Complete Availability Assumptions in EPA Base Case v.5.13

This is a small excerpt of the data in Table 3-18. The complete data set in spreadsheet format can be downloaded via the link found at www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html . Please see Table 3-19 for summary data

Unit ID	Plant Name	Plant Type	Winter Availability	Summer Availability	Annual Availability
55522_G_CT1	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT10	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT2	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT3	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT4	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT5	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT6	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT7	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT8	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT9	Sundance	Combustion Turbine	89.2	90.8	89.9
55257_G_1	Ina Road Water Pollution Control Fac	Combustion Turbine	88.4	90.4	89.2
55257_G_2	Ina Road Water Pollution Control Fac	Combustion Turbine	88.4	90.4	89.2
55257_G_3	Ina Road Water Pollution Control Fac	Combustion Turbine	88.4	90.4	89.2
55257_G_4	Ina Road Water Pollution Control Fac	Combustion Turbine	88.4	90.4	89.2
55257_G_5	Ina Road Water Pollution Control Fac	Combustion Turbine	88.4	90.4	89.2
55257_G_6	Ina Road Water Pollution Control Fac	Combustion Turbine	88.4	90.4	89.2
55257_G_7	Ina Road Water Pollution Control Fac	Combustion Turbine	88.4	90.4	89.2
82755_C_1	AZNM_AZ_Combustion Turbine	Combustion Turbine	89.8	92.2	90.8
6088_G_5	North Loop	Combustion Turbine	89.2	90.8	89.9
118_G_GE1	Saguaro	Combustion Turbine	89.8	92.2	90.8
124_G_GT2	Demoss Petrie	Combustion Turbine	89.8	92.2	90.8
82757_C_1	AZNM_CA_Combustion Turbine	Combustion Turbine	89.8	92.2	90.8
2468_G_6	Raton	Combustion Turbine	88.4	90.4	89.2
82759_C_1	AZNM_NM_Combustion Turbine	Combustion Turbine	89.8	92.2	90.8
54814_G_GENA	Milagro Cogeneration Plant	Combustion Turbine	89.2	90.8	89.9

Table 3-19 BART Regulations included in EPA Base Case v.5.13

BART Affected Plants	UniqueID	BART Status/ CAIR/ Shutdown/ Coal-to-Gas	NO_x BART Limit	SO_2 BART Limit	NO_x Compliance Date	SO_2 Compliance Date
Colstrip	6076_B_1	BART NO_x	0.15 lb/MMBtu		2018	2018
Colstrip	6076_B_2	BART NO_x	0.15 lb/MMBtu		2018	2018
Comanche	470_B_1	BART NO_x	0.20 lb/MMBtu		2018	2018
Comanche	470_B_2	BART NO_x	0.20 lb/MMBtu		2018	2018
Craig	6021_B_C1	BART NO_x	0.27 lb/MMBtu		2018	2018
Craig	6021_B_C2	BART NO_x	0.08 lb/MMBtu		2018	2018
Four Corners	2442_B_1	BART NO_x	0.05 lb/MMBtu	Acutal emissions	2018	2018
Four Corners	2442_B_2	BART NO_x	0.05 lb/MMBtu	Acutal emissions	2018	2018
Four Corners	2442_B_3	BART NO_x	0.05 lb/MMBtu	Acutal emissions	2018	2018
Four Corners	2442_B_4	BART NO_x	0.05 lb/MMBtu	Acutal emissions	2018	2018
Four Corners	2442_B_5	BART NO_x	0.05 lb/MMBtu	Acutal emissions	2018	2018
Gerald Gentleman	6077_B_1	BART NO_x	0.23 lb/MMBtu	TBD	2018	2018
Gerald Gentleman	6077_B_2	BART NO_x	0.23 lb/MMBtu	TBD	2018	2018
Hayden	525_B_H1	BART NO_x	0.08 lb/MMBtu		2018	2018
Hayden	525_B_H2	BART NO_x	0.07 lb/MMBtu		2018	2018
J E Corette Plant	2187_B_2	BART NO_x	0.35 lb/MMBtu		2018	2018
Martin Drake	492_B_5	BART NO_x	0.31 lb/MMBtu		2018	2018
Martin Drake	492_B_6	BART NO_x	0.32 lb/MMBtu		2018	2018
Martin Drake	492_B_7	BART NO_x	0.32 lb/MMBtu		2018	2018
Nebraska City	6096_B_1	BART NO_x	0.23 lb/MMBtu		2018	2018
Reid Gardner	2324_B_1	BART NO_x	0.20 lb/MMBtu		2018	2018
Reid Gardner	2324_B_2	BART NO_x	0.20 lb/MMBtu		2018	2018
Reid Gardner	2324_B_3	BART NO_x	0.20 lb/MMBtu		2018	2018
San Juan	2451_B_1	BART NO_x	0.11 lb/MMBtu	Acutal emissions	2018	2018
San Juan	2451_B_2	BART NO_x	0.11 lb/MMBtu	Acutal emissions	2018	2018
San Juan	2451_B_3	BART NO_x	0.11 lb/MMBtu	Acutal emissions	2018	2018
San Juan	2451_B_4	BART NO_x	0.11 lb/MMBtu	Acutal emissions	2018	2018
Tecumseh Energy Center	1252_B_10	BART NO_x	0.18 lb/MMBtu		2018	2018
Apache Station	160_B_2	BART NO_x & BART SO_2	0.07 lb/MMBtu across 2 units	0.15 lb/MMBtu	12/1/17	12/1/16
Apache Station	160_B_3	BART NO_x & BART SO_2	0.07 lb/MMBtu across 2 units	0.15 lb/MMBtu	12/1/17	12/1/16
Cherokee	469_B_4	BART NO_x & BART SO_2	0.12 lb/MMBtu	7.81 tpy (12 month rolling)	2018	2018
Cholla	113_B_2	BART NO_x & BART SO_2	0.055 lb/MMBtu across 3 units	0.15 lb/MMBtu	12/1/17	12/5/13
Cholla	113_B_3	BART NO_x & BART SO_2	0.055 lb/MMBtu across 3 units	0.15 lb/MMBtu	12/1/17	12/5/13
Cholla	113_B_4	BART NO_x & BART SO_2	0.055 lb/MMBtu across 3 units	0.15 lb/MMBtu	12/1/17	12/5/13
Coal Creek	6030_B_1	BART NO_x & BART SO_2	0.13 lb/MMBtu (combined both units)	0.15 lb/MMBtu or 95% efficiency	2018	2018
Coal Creek	6030_B_2	BART NO_x & BART SO_2	0.13 lb/MMBtu (combined both units)	0.15 lb/MMBtu or 95% efficiency	2018	2018
Coronado	6177_B_U1B	BART NO_x & BART SO_2	0.065 lb/MMBtu across 2 units	0.08 lb/MMBtu	12/1/17	6/5/13
Coronado	6177_B_U2B	BART NO_x & BART SO_2	0.065 lb/MMBtu across 2 units	0.08 lb/MMBtu	12/1/17	6/5/13
Jeffrey Energy Center	6068_B_1	BART NO_x & BART SO_2	0.15 lb/MMBtu	0.15 lb/MMBtu	2018	2018
Jeffrey Energy Center	6068_B_2	BART NO_x & BART SO_2	0.15 lb/MMBtu	0.15 lb/MMBtu	2018	2018

BART Affected Plants	UniqueID	BART Status/ CAIR/ Shutdown/ Coal-to-Gas	NO_x BART Limit	SO_2 BART Limit	NO_x Compliance Date	SO_2 Compliance Date
La Cygne	1241_B_1	BART NO_x & BART SO_2	0.13 lb/MMBtu (combined both units)	0.15 lb/MMBtu	6/1/15	6/1/15
La Cygne	1241_B_2	BART NO_x & BART SO_2	0.13 lb/MMBtu (combined both units)	0.15 lb/MMBtu	6/1/15	6/1/15
Leland Olds	2817_B_1	BART NO_x & BART SO_2	0.19 lb/MMBtu	0.15 lb/MMBtu or 95% efficiency	2018	2018
Leland Olds	2817_B_2	BART NO_x & BART SO_2	0.35 lb/MMBtu	0.15 lb/MMBtu or 95% efficiency	2018	2018
Merrimack	2364_B_2	BART NO_x & BART SO_2	0.30 lb/MMBtu	90 % control	2018	2018
Milton R Young	2823_B_B1	BART NO_x & BART SO_2	0.36 lb/MMBtu	0.15 lb/MMBtu or 95% efficiency	2018	2018
Milton R Young	2823_B_B2	BART NO_x & BART SO_2	0.35 lb/MMBtu	0.15 lb/MMBtu or 95% efficiency	2018	2018
Muskogee	2952_B_4	BART NO_x & BART SO_2	0.15 lb/MMBtu	0.06 lbs/MMBtu	2018	2018
Muskogee	2952_B_5	BART NO_x & BART SO_2	0.15 lb/MMBtu	0.06 lbs/MMBtu	2018	2018
Pawnee	6248_B_1	BART NO_x & BART SO_2	0.07 lb/MMBtu	0.12 lb/MMBtu	2018	2018
Ray D Nixon	8219_B_1	BART NO_x & BART SO_2	0.21 lb/MMBtu	0.11 lb/MMBtu	2018	2018
Sooner	6095_B_1	BART NO_x & BART SO_2	0.15 lb/MMBtu	0.06 lbs/MMBtu	2018	2018
Sooner	6095_B_2	BART NO_x & BART SO_2	0.15 lb/MMBtu	0.06 lbs/MMBtu	2018	2018
Stanton	2824_B_1	BART NO_x & BART SO_2	0.29 lb/MMBtu	0.24 lb/MMBtu	2018	2018
Lansing Smith	643_B_1	BART NO_x & BART SO_2	4700 tpy across 2 units	0.74 lb/MMBtu	2018	2018
Lansing Smith	643_B_2	BART NO_x & BART SO_2	4700 tpy across 2 units	0.74 lb/MMBtu	2018	2018
Northeastern	2963_B_3313	BART NO_x & BART SO_2; Shutdown by 2016	0.23 lb/MMBtu	0.60 lb/MMBtu	2018	2018
Boardman	6106_B_1SG	BART NO_x & BART SO_2; Shutdown by 2020	0.7 lb/MMBtu	1.2 lb/MMBtu	2018	2018
Northeastern	2963_B_3314	BART NO_x & BART SO_2; Shutdown by 2024	0.15 lb/MMBtu	0.40 lb/MMBtu	2018	2018
Seminole	136_B_1	BART SO_2		0.25 lb/MMBtu	2018	2018
Seminole	136_B_2	BART SO_2		0.25 lb/MMBtu	2018	2018
Northside Generating Station	667_B_1	BART SO_2		3600 tpy across 3 units	2018	2018
Northside Generating Station	667_B_2	BART SO_2		3600 tpy across 3 units	2018	2018
Northside Generating Station	667_B_3	BART SO_2		3600 tpy across 3 units	2018	2018
Deerhaven Generating Station	663_B_B2	BART SO_2		5500 tpy	2018	2018
Merrimack	2364_B_2	BART SO_2		Actual Emissions [with FGD]	2018	2018
Yates	728_B_Y6BR	Coal-to-Gas by 2016				
Yates	728_B_Y7BR	Coal-to-Gas by 2016				
George Neal North	1091_B_1	Coal-to-Gas by 4/16/2016				
George Neal North	1091_B_2	Coal-to-Gas by 4/16/2016				
George Neal North	1091_B_3	Coal-to-Gas by 4/16/2016				
Walter Scott Jr. Energy Center	1082_B_3	Coal-to-Gas by 4/16/2016				
A B Brown	6137_B_1	CAIR				
Ames Electric Services Power Plant	1122_B_7	CAIR				

BART Affected Plants	UniqueID	BART Status/ CAIR/ Shutdown/ Coal-to-Gas	NO_x BART Limit	SO_2 BART Limit	NO_x Compliance Date	SO_2 Compliance Date
Asbury	2076_B_1	CAIR				
Bailly	995_B_7	CAIR				
Bailly	995_B_8	CAIR				
Barry	3_B_4	CAIR				
Barry	3_B_5	CAIR				
Belle River	6034_B_1	CAIR				
Belle River	6034_B_2	CAIR				
Big Brown	3497_B_1	CAIR				
Big Brown	3497_B_2	CAIR				
Big Cajun 2	6055_B_2B1	CAIR				
Big Stone	6098_B_1	CAIR				
Blue Valley	2132_B_3	CAIR				
Bowen	703_B_1BLR	CAIR				
Bowen	703_B_2BLR	CAIR				
Bowen	703_B_3BLR	CAIR				
Bowen	703_B_4BLR	CAIR				
Bridgeport Station	568_B_BHB3	CAIR				
Bruce Mansfield	6094_B_1	CAIR				
Bruce Mansfield	6094_B_2	CAIR				
Bruce Mansfield	6094_B_3	CAIR				
Bull Run	3396_B_1	CAIR				
Burlington	1104_B_1	CAIR				
Capitol Heat and Power	54406_G_1	CAIR				
Capitol Heat and Power	54406_G_2	CAIR				
Cardinal	2828_B_1	CAIR				
Cardinal	2828_B_2	CAIR				
Cardinal	2828_B_3	CAIR				
Cayuga	1001_B_1	CAIR				
Cayuga	1001_B_2	CAIR				
Charles R Lowman	56_B_1	CAIR				
Charles R Lowman	56_B_2	CAIR				
Charles R Lowman	56_B_3	CAIR				
Chesterfield	3797_B_5	CAIR				
Chesterfield	3797_B_6	CAIR				
Cheswick	8226_B_1	CAIR				
Colbert	47_B_5	CAIR				
Coleto Creek	6178_B_1	CAIR				
Columbia	8023_B_1	CAIR				
Columbia	8023_B_2	CAIR				
Conemaugh	3118_B_1	CAIR				
Conemaugh	3118_B_2	CAIR				
Conesville	2840_B_4	CAIR				
Conesville	2840_B_5	CAIR				
Conesville	2840_B_6	CAIR				
Cooper	1384_B_1	CAIR				
Cooper	1384_B_2	CAIR				
Crawfordsville	1024_B_6	CAIR				
Cumberland	3399_B_1	CAIR				
Cumberland	3399_B_2	CAIR				
Dean H Mitchell	996_B_11	CAIR				
Dolphus M Grainger	3317_B_1	CAIR				
Dolphus M Grainger	3317_B_2	CAIR				
Dover	2914_B_4	CAIR				
E C Gaston	26_B_4	CAIR				

BART Affected Plants	UniqueID	BART Status/ CAIR/ Shutdown/ Coal-to-Gas	NO_x BART Limit	SO_2 BART Limit	NO_x Compliance Date	SO_2 Compliance Date
E C Gaston	26_B_5	CAIR				
E W Brown	1355_B_2	CAIR				
E W Brown	1355_B_3	CAIR				
East Bend	6018_B_2	CAIR				
Eckert Station	1831_B_4	CAIR				
Eckert Station	1831_B_5	CAIR				
Eckert Station	1831_B_6	CAIR				
Elmer Smith	1374_B_1	CAIR				
Elmer Smith	1374_B_2	CAIR				
Erickson Station	1832_B_1	CAIR				
F B Culley	1012_B_2	CAIR				
F B Culley	1012_B_3	CAIR				
Fair Station	1218_B_2	CAIR				
Fayette Power Project	6179_B_1	CAIR				
Fayette Power Project	6179_B_2	CAIR				
Fort Martin Power Station	3943_B_1	CAIR				
Fort Martin Power Station	3943_B_2	CAIR				
General James M Gavin	8102_B_1	CAIR				
General James M Gavin	8102_B_2	CAIR				
Genoa	4143_B_1	CAIR				
George Neal South	7343_B_4	CAIR				
Ghent	1356_B_1	CAIR				
Ghent	1356_B_2	CAIR				
Ghent	1356_B_3	CAIR				
Gibson	6113_B_1	CAIR				
Gibson	6113_B_2	CAIR				
Gibson	6113_B_3	CAIR				
Gibson	6113_B_4	CAIR				
Gorgas	8_B_10	CAIR				
Greene County	10_B_1	CAIR				
Greene County	10_B_2	CAIR				
H L Spurlock	6041_B_1	CAIR				
H L Spurlock	6041_B_2	CAIR				
Hamilton	2917_B_8	CAIR				
Hamilton	2917_B_9	CAIR				
Hammond	708_B_4	CAIR				
Harding Street	990_B_70	CAIR				
Harrington	6193_B_061B	CAIR				
Harrington	6193_B_062B	CAIR				
Harrington	6193_B_063B	CAIR				
Harrison Power Station	3944_B_1	CAIR				
Harrison Power Station	3944_B_2	CAIR				
Harrison Power Station	3944_B_3	CAIR				
Hatfields Ferry Power Station	3179_B_1	CAIR				
Hatfields Ferry Power Station	3179_B_2	CAIR				
Hatfields Ferry Power Station	3179_B_3	CAIR				
Henderson	2062_B_H3	CAIR				
HMP&L Station Two Henderson	1382_B_H2	CAIR				
Homer City Station	3122_B_1	CAIR				
Homer City Station	3122_B_2	CAIR				
Homer City Station	3122_B_3	CAIR				
Iatan	6065_B_1	CAIR				
J H Campbell	1710_B_1	CAIR				
J H Campbell	1710_B_2	CAIR				

BART Affected Plants	UniqueID	BART Status/ CAIR/ Shutdown/ Coal-to-Gas	NO_x BART Limit	SO_2 BART Limit	NO_x Compliance Date	SO_2 Compliance Date
J H Campbell	1710_B_3	CAIR				
J M Stuart	2850_B_1	CAIR				
J M Stuart	2850_B_2	CAIR				
J M Stuart	2850_B_3	CAIR				
J M Stuart	2850_B_4	CAIR				
Jack McDonough	710_B_MB1	CAIR				
Jack McDonough	710_B_MB2	CAIR				
Jack Watson	2049_B_4	CAIR				
Jack Watson	2049_B_5	CAIR				
James De Young	1830_B_4	CAIR				
James De Young	1830_B_5	CAIR				
James H Miller Jr	6002_B_2	CAIR				
James H Miller Jr	6002_B_1	CAIR				
James River Power Station	2161_B_4	CAIR				
James River Power Station	2161_B_5	CAIR				
Jasper 2	6225_B_1	CAIR				
John E Amos	3935_B_1	CAIR				
John E Amos	3935_B_2	CAIR				
John E Amos	3935_B_3	CAIR				
John P Madgett	4271_B_B1	CAIR				
Kenneth C Coleman	1381_B_C1	CAIR				
Kenneth C Coleman	1381_B_C2	CAIR				
Kenneth C Coleman	1381_B_C3	CAIR				
Keystone	3136_B_1	CAIR				
Keystone	3136_B_2	CAIR				
Labadie	2103_B_1	CAIR				
Labadie	2103_B_2	CAIR				
Labadie	2103_B_3	CAIR				
Labadie	2103_B_4	CAIR				
Lake Road	2098_B_6	CAIR				
Lake Road	2908_G_11	CAIR				
Lake Shore	2838_B_18	CAIR				
Lansing	1047_B_4	CAIR				
Logansport	1032_B_6	CAIR				
Manitowoc	4125_B_7	CAIR				
Marshall	2144_B_5	CAIR				
Martin Lake	6146_B_1	CAIR				
Martin Lake	6146_B_2	CAIR				
Martin Lake	6146_B_3	CAIR				
McIntosh	6124_B_1	CAIR				
Merom	6213_B_1SG1	CAIR				
Merom	6213_B_2SG1	CAIR				
Miami Fort	2832_B_7	CAIR				
Miami Fort	2832_B_8	CAIR				
Michigan City	997_B_12	CAIR				
Mill Creek	1364_B_1	CAIR				
Mill Creek	1364_B_2	CAIR				
Mill Creek	1364_B_3	CAIR				
Mill Creek	1364_B_4	CAIR				
Milton L Kapp	1048_B_2	CAIR				
Mitchell	3948_B_1	CAIR				
Mitchell	3948_B_2	CAIR				
Mitchell Power Station	3181_B_33	CAIR				
Monroe	1733_B_1	CAIR				

BART Affected Plants	UniqueID	BART Status/ CAIR/ Shutdown/ Coal-to-Gas	NO_x BART Limit	SO_2 BART Limit	NO_x Compliance Date	SO_2 Compliance Date
Monroe	1733_B_2	CAIR				
Monroe	1733_B_3	CAIR				
Monroe	1733_B_4	CAIR				
Monticello	6147_B_1	CAIR				
Monticello	6147_B_2	CAIR				
Monticello	6147_B_3	CAIR				
Montrose	2080_B_3	CAIR				
Mountaineer	6264_B_1	CAIR				
Mt Storm	3954_B_1	CAIR				
Mt Storm	3954_B_2	CAIR				
Mt Storm	3954_B_3	CAIR				
Muscatine Plant #1	1167_B_8	CAIR				
Muskingum River	2872_B_5	CAIR				
New Madrid	2167_B_1	CAIR				
New Madrid	2167_B_2	CAIR				
Orrville	2935_B_13	CAIR				
Ottumwa	6254_B_1	CAIR				
Paradise	1378_B_1	CAIR				
Paradise	1378_B_2	CAIR				
Paradise	1378_B_3	CAIR				
Petersburg	994_B_1	CAIR				
Petersburg	994_B_2	CAIR				
Petersburg	994_B_3	CAIR				
Pleasant Prairie	6170_B_1	CAIR				
Pleasants Power Station	6004_B_1	CAIR				
Pleasants Power Station	6004_B_2	CAIR				
PPL Brunner Island	3140_B_2	CAIR				
PPL Brunner Island	3140_B_3	CAIR				
PPL Montour	3149_B_1	CAIR				
PPL Montour	3149_B_2	CAIR				
Prairie Creek	1073_B_4	CAIR				
Presque Isle	1769_B_5	CAIR				
Presque Isle	1769_B_6	CAIR				
Presque Isle	1769_B_7	CAIR				
Presque Isle	1769_B_8	CAIR				
Presque Isle	1769_B_9	CAIR				
Pulliam	4072_B_8	CAIR				
R D Green	6639_B_G1	CAIR				
R D Green	6639_B_G2	CAIR				
R D Morrow	6061_B_1	CAIR				
R D Morrow	6061_B_2	CAIR				
R M Schahfer	6085_B_14	CAIR				
R M Schahfer	6085_B_15	CAIR				
R S Nelson	1393_B_6	CAIR				
Robert A Reid	1383_B_R1	CAIR				
Rodemacher	6190_B_2	CAIR				
Rush Island	6155_B_1	CAIR				
Rush Island	6155_B_2	CAIR				
Sandow	6648_B_4	CAIR				
Scherer	6257_B_1	CAIR				
Scherer	6257_B_2	CAIR				
Shelby Municipal Light Plant	2943_B_1	CAIR				
Shelby Municipal Light Plant	2943_B_2	CAIR				
Shiras	1843_B_2	CAIR				

BART Affected Plants	UniqueID	BART Status/ CAIR/ Shutdown/ Coal-to-Gas	NO_x BART Limit	SO_2 BART Limit	NO_x Compliance Date	SO_2 Compliance Date
Sibley	2094_B_2	CAIR				
Sibley	2094_B_3	CAIR				
Sikeston Power Station	6768_B_1	CAIR				
Sioux	2107_B_1	CAIR				
Sioux	2107_B_2	CAIR				
South Oak Creek	4041_B_7	CAIR				
South Oak Creek	4041_B_8	CAIR				
Southwest Power Station	6195_B_1	CAIR				
St Clair	1743_B_7	CAIR				
St Marys	2942_B_6	CAIR				
Streeter Station	1131_B_6	CAIR				
Streeter Station	1131_B_7	CAIR				
Tanners Creek	988_B_U4	CAIR				
Thomas Hill	2168_B_MB1	CAIR				
Thomas Hill	2168_B_MB2	CAIR				
Trenton Channel	1745_B_9A	CAIR				
Valley	4042_B_1	CAIR				
Valley	4042_B_2	CAIR				
Valley	4042_B_3	CAIR				
Valley	4042_B_4	CAIR				
Victor J Daniel Jr	6073_B_1	CAIR				
Victor J Daniel Jr	6073_B_2	CAIR				
W A Parish	3470_B_WAP5	CAIR				
W A Parish	3470_B_WAP6	CAIR				
W A Parish	3470_B_WAP7	CAIR				
W H Sammis	2866_B_4	CAIR				
W H Sammis	2866_B_5	CAIR				
W H Sammis	2866_B_6	CAIR				
W H Sammis	2866_B_7	CAIR				
Wabash River	1010_B_6	CAIR				
Wansley	6052_B_1	CAIR				
Wansley	6052_B_2	CAIR				
Warrick	6705_B_2	CAIR				
Warrick	6705_B_3	CAIR				
Warrick	6705_B_4	CAIR				
Wateree	3297_B_WAT1	CAIR				
Wateree	3297_B_WAT2	CAIR				
Welsh	6139_B_1	CAIR				
Weston	4078_B_3	CAIR				
Whitewater Valley	1040_B_2	CAIR				
Widows Creek	50_B_8	CAIR				
Williams	3298_B_WIL1	CAIR				
Winyah	6249_B_1	CAIR				
Winyah	6249_B_2	CAIR				
Asheville	2706_B_1	CAIR/State EGU Rule				
Asheville	2706_B_2	CAIR/State EGU Rule				
Belews Creek	8042_B_1	CAIR/State EGU Rule				
Belews Creek	8042_B_2	CAIR/State EGU Rule				
Cliffside	2721_B_5	CAIR/State EGU Rule				
Marshall	2727_B_1	CAIR/State EGU Rule				
Marshall	2727_B_2	CAIR/State EGU Rule				
Marshall	2727_B_3	CAIR/State EGU Rule				
Marshall	2727_B_4	CAIR/State EGU Rule				
Roxboro	2712_B_1	CAIR/State EGU Rule				

BART Affected Plants	UniqueID	BART Status/ CAIR/ Shutdown/ Coal-to-Gas	NO_x BART Limit	SO_2 BART Limit	NO_x Compliance Date	SO_2 Compliance Date
Roxboro	2712_B_2	CAIR/State EGU Rule				
Roxboro	2712_B_3A	CAIR/State EGU Rule				
Roxboro	2712_B_3B	CAIR/State EGU Rule				
Roxboro	2712_B_4A	CAIR/State EGU Rule				
Roxboro	2712_B_4B	CAIR/State EGU Rule				
Lee	2709_B_3	CAIR/State EGU Rule; Shutdown by 2013				
L V Sutton	2713_B_3	CAIR/State EGU Rule; Shutdown by 2017				
Portland	3113_B_2	CAIR; Shutdown by 1/7/2015				
Harllee Branch	709_B_2	CAIR; Shutdown by 10/1/13				
Canadys Steam	3280_B_CAN1	CAIR; Shutdown by 12/1/2017				
Canadys Steam	3280_B_CAN2	CAIR; Shutdown by 12/1/2017				
Canadys Steam	3280_B_CAN3	CAIR; Shutdown by 12/1/2017				
Harllee Branch	709_B_1	CAIR; Shutdown by 12/31/13				
Chesapeake	3803_B_4	CAIR; Shutdown by 12/31/14				
Welsh	6139_B_2	CAIR; Shutdown by 12/31/14				
Conesville	2840_B_3	CAIR; Shutdown by 12/31/2012				
HMP&L Station Two Henderson	1382_B_H1	CAIR; Shutdown by 2008				
Menasha	4127_B_B24	CAIR; Shutdown by 2009				
Pella	1175_B_6	CAIR; Shutdown by 2012				
Pella	1175_B_7	CAIR; Shutdown by 2012				
Jefferies	3319_B_3	CAIR; Shutdown by 2013				
Jefferies	3319_B_4	CAIR; Shutdown by 2013				
Big Sandy	1353_B_BSU2	CAIR; Shutdown by 2015				
Frank E Ratts	1043_B_1SG1	CAIR; Shutdown by 2015				
Frank E Ratts	1043_B_2SG1	CAIR; Shutdown by 2015				
Harbor Beach	1731_B_1	CAIR; Shutdown by 2015				
Nelson Dewey	4054_B_2	CAIR; Shutdown by 2015				
Cane Run	1363_B_4	CAIR; Shutdown by 2016				
Cane Run	1363_B_5	CAIR; Shutdown by 2016				
Cane Run	1363_B_6	CAIR; Shutdown by 2016				
Harllee Branch	709_B_3	CAIR; Shutdown by 2016				
Harllee Branch	709_B_4	CAIR; Shutdown by 2016				
Kraft	733_B_3	CAIR; Shutdown by 2016				
J T Deely	6181_B_1	CAIR; Shutdown by 2018				
J T Deely	6181_B_2	CAIR; Shutdown by 2018				
State Line	981_B_4	CAIR; Shutdown by 3/25/12				
Avon Lake	2836_B_12	CAIR; Shutdown by 4/1/2015				
Walter C Beckjord	2830_B_5	CAIR; Shutdown by 4/1/2015				
Walter C Beckjord	2830_B_6	CAIR; Shutdown by 4/1/2015				
New Castle	3138_B_5	CAIR; Shutdown by 4/16/2015				
Big Sandy	1353_B_BSU1	CAIR; Shutdown by 6/1/2015				
Bay Shore	2878_B_3	CAIR; Shutdown by 9/1/2012				
Bay Shore	2878_B_4	CAIR; Shutdown by 9/1/2012				
Eastlake	2837_B_5	CAIR; Shutdown by 9/1/2012				
Edgewater	4050_B_4	CAIR; Shutdown or Coal-to-Gas by 12/31/2018				
Dave Johnston	4158_B_BW43	Proposal 5/23/13				
Dave Johnston	4158_B_BW44	Proposal 5/23/13				
Jim Bridger	8066_B_BW71	Proposal 5/23/13				
Jim Bridger	8066_B_BW72	Proposal 5/23/13				
Jim Bridger	8066_B_BW73	Proposal 5/23/13				

BART Affected Plants	UniqueID	BART Status/ CAIR/ Shutdown/ Coal-to-Gas	NO_x BART Limit	SO_2 BART Limit	NO_x Compliance Date	SO_2 Compliance Date
Jim Bridger	8066_B_BW74	Proposal 5/23/13				
Laramie River Station	6204_B_1	Proposal 5/23/13				
Laramie River Station	6204_B_2	Proposal 5/23/13				
Naughton	4162_B_1	Proposal 5/23/13				
Naughton	4162_B_2	Proposal 5/23/13				
Naughton	4162_B_3	Proposal 5/23/13				
Neil Simpson	4150_B_5	Proposal 5/23/13				
Wyodak	6101_B_BW91	Proposal 5/23/13				
Navajo	4941_B_1	Proposed				
Navajo	4941_B_2	Proposed				
Navajo	4941_B_3	Proposed				
Indian River Generating Station	594_B_3	Shutdown by 12/31/13; State EGU Rule				
Cherokee	469_B_3	Shutdown by 12/31/16				
Valmont	477_B_5	Shutdown by 12/31/17				
Crystal River	628_B_1	Shutdown by 2020				
Crystal River	628_B_2	Shutdown by 2020				
Transalta Centralia Generation	3845_B_BW21	Shutdown by 2020				
Transalta Centralia Generation	3845_B_BW22	Shutdown by 2025				
Brayton Point	1619_B_1	State Alternative Program				
Brayton Point	1619_B_2	State Alternative Program				
Brayton Point	1619_B_3	State Alternative Program				
Baldwin Energy Complex	889_B_1	State EGU Rule				
Baldwin Energy Complex	889_B_2	State EGU Rule				
Baldwin Energy Complex	889_B_3	State EGU Rule				
C P Crane	1552_B_2	State EGU Rule				
Chalk Point LLC	1571_B_1	State EGU Rule				
Chalk Point LLC	1571_B_2	State EGU Rule				
Coffeen	861_B_01	State EGU Rule				
Coffeen	861_B_02	State EGU Rule				
Dallman	963_B_31	State EGU Rule				
Dallman	963_B_32	State EGU Rule				
Dallman	963_B_33	State EGU Rule				
Dickerson	1572_B_3	State EGU Rule				
Duck Creek	6016_B_1	State EGU Rule				
E D Edwards	856_B_2	State EGU Rule				
E D Edwards	856_B_3	State EGU Rule				
Edge Moor	593_B_4	State EGU Rule				
Havana	891_B_9	State EGU Rule				
Herbert A Wagner	1554_B_3	State EGU Rule				
Indian River Generating Station	594_B_4	State EGU Rule				
Joliet 29	384_B_71	State EGU Rule				
Joliet 29	384_B_72	State EGU Rule				
Joliet 29	384_B_81	State EGU Rule				
Joliet 29	384_B_82	State EGU Rule				
Kincaid Generation LLC	876_B_1	State EGU Rule				
Kincaid Generation LLC	876_B_2	State EGU Rule				
Marion	976_B_4	State EGU Rule				
Marion	976_B_123	State EGU Rule				
Morgantown Generating Plant	1573_B_1	State EGU Rule				
Morgantown Generating Plant	1573_B_2	State EGU Rule				
Newton	6017_B_1	State EGU Rule				
Newton	6017_B_2	State EGU Rule				
Pearl Station	6238_B_1A	State EGU Rule				
Powerton	879_B_51	State EGU Rule				

BART Affected Plants	UniqueID	BART Status/ CAIR/ Shutdown/ Coal-to-Gas	NO_x BART Limit	SO_2 BART Limit	NO_x Compliance Date	SO_2 Compliance Date
Powerton	879_B_52	State EGU Rule				
Powerton	879_B_61	State EGU Rule				
Powerton	879_B_62	State EGU Rule				
PSEG Hudson Generating Station	2403_B_2	State EGU Rule				
Waukegan	883_B_8	State EGU Rule				
Will County	884_B_4	State EGU Rule				
Wood River	898_B_5	State EGU Rule				
Austin Northeast	1961_B_NEPP	TBD				
Clay Boswell	1893_B_3	TBD				
Clay Boswell	1893_B_4	TBD				
H Wilson Sundt GS	126_B_4	TBD				
Hibbing	1979_B_1	TBD				
Hibbing	1979_B_2	TBD				
Hibbing	1979_B_3	TBD				
Hoot Lake (Otter Tail)	1943_B_3	TBD				
Sherburne County	6090_B_1	TBD				
Sherburne County	6090_B_2	TBD				
Silver Bay Power	10849_B_BLR2	TBD				
Silver Lake	2008_B_3	TBD				
Silver Lake	2008_B_4	TBD				
Allen S King	1915_B_1	TBD				
Big Bend	645_B_BB01	TBD Proposed				
Big Bend	645_B_BB02	TBD Proposed				
Big Bend	645_B_BB03	TBD Proposed				
Crist	641_B_6	TBD Proposed				
Crist	641_B_7	TBD Proposed				
Crystal River	628_B_4	TBD Proposed				
Crystal River	628_B_5	TBD Proposed				
Deerhaven Generating Station	663_B_B2	TBD Proposed				
Lansing Smith	643_B_1	TBD Proposed				
Lansing Smith	643_B_2	TBD Proposed				
Flint Creek	6138_B_1	TBD State SIP disapproved				
Hunter	6165_B_1	TBD State SIP disapproved				
Hunter	6165_B_2	TBD State SIP disapproved				
Huntington	8069_B_1	TBD State SIP disapproved				
Huntington	8069_B_2	TBD State SIP disapproved				
White Bluff	6009_B_1	TBD State SIP disapproved				
White Bluff	6009_B_2	TBD State SIP disapproved				