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.4.10.

3.1 Model Regions

EPA Base Case v.4.10 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[4]) as an integrated network. Alaska, Hawaii, Puerto Rico, and US Virgin Islands are represented in Base Case v.4.10 as separate entities with their own self contained electricity grids.

There are 32 IPM model regions covering the US 48 states and District of Columbia. The IPM model regions are approximately consistent with the configuration of the 8 NERC regions, being disaggregations of North American Reliability Council (NERC) control areas. An attempt has been made to have the US IPM model regions reflect the administrative structure of regional transmission organizations (RTOs) and independent system operators (ISOs). Further disaggregation into 32 model regions allows a more accurate characterization of the operation of the US power markets by providing the ability to represent transmission bottlenecks within the 8 NERC regions and across RTOs and ISOs.

Disaggregations that were made in the most recent previous IPM base case were retained in Base Case 2010. Notable disaggregations include

- NERC region RFC (Reliability First Corporation) includes three portions of former NERC regions — the non-Kentucky part of ECAR, MAAC, and a portion of MAIN. The remaining portion of MAIN has been renamed COMD. ECAR has been disaggregated into RFCO, MECS, and RFCP and MAAC has been disaggregated into MACE, MACS, and MACW.

- NERC subregion WECC-AZ-NM-SNV has been disaggregated into AZNM and SNV

- NERC subregion WECC-California ISO has been disaggregated into CA-N and CA-S

- NERC Region SERC has been disaggregated into 7 IPM regions (ENTG, SOU, VACA, VAPW, TVA, TVAK (formerly ECAK), and GWAY (formerly a portion of MANO).

Several region boundaries were adjusted to reflect recent organizational changes. There were also several name changes: MANO to GWAY, ECAM to RFCO, ECAP to RFCP, and ECAK to TVAK.

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

Figure 3-1 contains a map showing all the EPA Base Case 2010 model regions. Table 3-1 defines the abbreviated region names appearing on the map and gives an approximate crosswalk between the IPM model regions, the NERC 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.

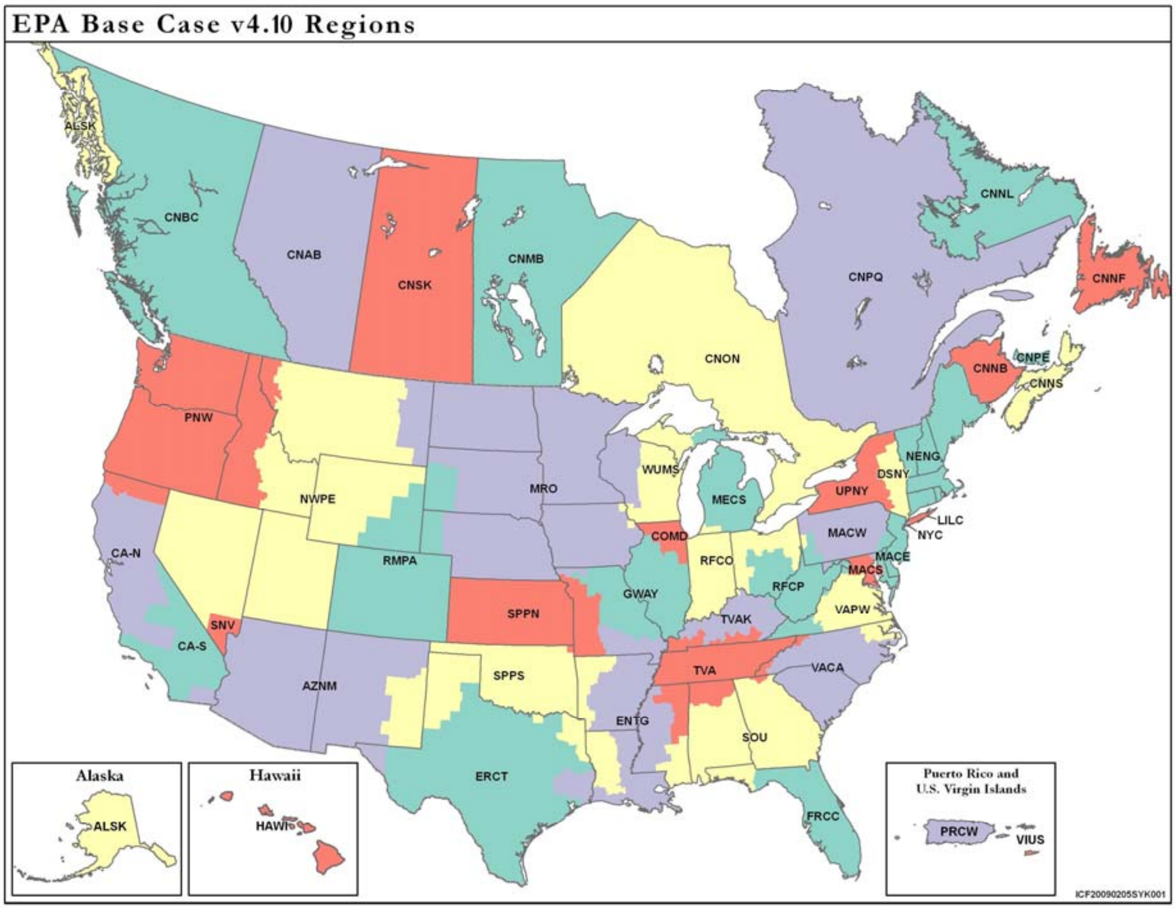
3.2 Electric Load Modeling

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

[4]This results in a total of 11 Candian model regions being represented in EPA Base Case v.4.10

(peak demand) is the maximum hourly demand within a given year after removing interruptible demand. Table 3-2 shows the electric demand assumptions (expressed as net energy for load) used in EPA Base Case v.4.10. It is based on the net energy for load in AEO 2010[5].

Figure 3-1 EPA Base Case v.4.10 Model Regions



For purposes of documentation, Table 3-2 presents the national net energy for load. However, EPA Base Case v.4.10 models regional breakdowns of net energy for load. The regional net energy for load is derived from the national net energy for load based on the regional demand distribution in NERC electric demand forecasts. Model regions that represent subregions of a NERC region are apportioned their net energy for load based on the regional load shapes, which are developed by aggregating load for control areas within each model region.

[5]The electricity demand in EPA Base Case v.4.10 for the U.S. lower 48 states and the District of Columbia is obtained by summing the "Total Net Energy for Load" for the NEMS Electric Market Module regions as reported in the "Electric Power Projections for Electricity Market Module Regions -- Electricity and Renewable Fuel Tables 72-84" at http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html.

Table 3-1 Mapping of NERC Regions and NEMS Regions with EPA Base Case v.4.10 Model Regions

NERC Region	NEMS Region	Model Region	Model Region Description
TRE	ERCOT	ERCT	Texas Regional Entity
FRCC	FL	FRCC	Florida Reliability Coordinating Council
MRO	MAPP	MRO	Midwest Regional Planning Organization
	MAIN	WUMS	Wisconsin-Upper Michigan
NPCC	NE	NENG	New England Power Pool
	NY	DSNY	Downstate New York
		LILC	Long Island Company
		NYC	New York City
		UPNY	Upstate New York
RFC	ECAR	RFCO	Reliability First Corporation - MISO
		MECS	Michigan Electric Coordination System
		RFCP	Reliability First Corporation - PJM
	MAAC	MACE	Legacy Mid-Atlantic Area Council - East
		MACS	Legacy Mid-Atlantic Area Council - South
		MACW	Legacy Mid-Atlantic Area Council - West
	MAIN	COMD	Commonwealth Edison
SERC	MAIN	GWAY	Gateway
	ECAR	TVAK	Tennessee Valley Authority - MISO-KY
	STV	SOU	Southern Company
		TVA	Tennessee Valley Authority
		ENTG	Entergy
		VACA	Virginia-Carolinas
		VAPW	Dominion Virginia Power
SPP	SPP	SPPN	Southwest Power Pool - North
		SPPS	Southwest Power Pool - South
WECC-AZ-NM-SNV	RA	AZNM	Western Electricity Coordinating Council - Arizona, New Mexico
		SNV	Western Electricity Coordinating Council - Southern Nevada
WECC-California ISO	CNV	CA-N	Western Electricity Coordinating Council - California North
		CA-S	Western Electricity Coordinating Council - California South
WECC-NWPP	NWP	PNW	Western Electricity Coordinating Council - Pacific Northwest
		NWPE	Western Electricity Coordinating Council - Northwest Power Pool East
WECC-RMPA	RA	RMPA	Western Electricity Coordinating Council - Rocky Mountain Power Area
Canada		CNAB	Alberta
		CNBC	British Columbia
		CNMB	Manitoba
		CNNB	New Brunswick
		CNNF	Newfoundland
		CNNL	Labrador
		CNNS	Nova Scotia
		CNON	Ontario

NERC Region	NEMS Region	Model Region	Model Region Description
		CNPE	Prince Edward Island
		CNPQ	Quebec
		CNSK	Saskatchewan
Other		ALSK	Alaska
		HAWI	Hawaii
		VIUS	U.S. Virgin Islands
		PRCW	Puerto Rico

Table 3-2 Electric Load Assumptions in EPA Base Case v.4.10

Year	Net Energy for Load (Billions of kWh)
2012	4,043
2015	4,086
2020	4,302
2030	4,703
2040	5,113
2050	5,568

Note:
This data is an aggregation of the model-region-specific net energy loads used in the EPA Base Case v.4.10.

3.2.1 Demand Elasticity

EPA Base Case v.4.10 has the capability to model the impact of the price of power on 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 is not affected by price and must be met, i.e., the price elasticity of demand is zero[6].

3.2.2 Net Internal Demand (Peak Demand)

EPA Base Case v.4.10 has separate regional winter and summer peak demand values, as derived from each region's seasonal load duration curve (found in Appendix 2-1). Peak projections were estimated based on AEO 2010 load factors and the estimated energy demand projections shown in Table 3-2. Table 3-3 ("National Non-Coincidental Net Internal Demand") 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.

[6]Occasionally, e.g., when performing modeling of climate policies, the demand assumptions shown in Table 3-2 will be replaced with projections of demand from economy-wide computable general equilibrium (CGE) models which themselves take into account demand elasticity. However, even in such cases the IPM demand elasticity capabilities will not be utilized and the resulting IPM runs will be considered "policy" rather than "base case" runs.

Table 3-3 National Non-Coincidental Net Internal Demand

Year	Peak Demand (GW)	
	Winter	Summer
2012	646	758
2015	655	771
2020	693	816
2030	768	908
2040	843	1,001
2050	929	1,105

Note:
This data is an aggregation of the model-region-specific peak demand loads used in the EPA Base Case v.4.10.

3.2.3 Regional Load Shapes

EPA uses year 2007 as the meteorological year in its air-quality modeling. In order for EPA Base Case v.4.10 to be consistent, the year 2007 was selected as the "normal weather year"[7] for all IPM regions. The proximity of the 2007 cumulative annual heating degree days (HDDs) and cooling degree days (CDDs) to the long-term average cumulative annual HHDs and CDDs over the period 1971 to 2000 was estimated and found to be reasonable close. The 2007 chronological hourly load data were assembled by aggregating individual utility load curves taken from Federal Energy Regulatory Commission Form 714 data.

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 4.10 characterizes the U.S. lower 48 states, the District of Columbia, and Canada into 43 different power market regions by means of 32 model regions in the U.S. and 11 in Canada. EPA Base Case 4.10 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 4.10.

3.3.1 Inter-regional Transmission Capability

Table 3-4[8] 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 (N-1). 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 (N-0). They specify the sum of the maximum firm transfer capability between sub-regions *plus* incremental curtailable non-firm transfer capability. Non-firm TTCs are used for energy transfers since they provide a lower level of reliability than

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[7]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.

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

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.4.10

From	To	Energy (MW)	Capacity (MW)	Wheeling Charge (mills/kWh)
AZNM	CA-S	3,627	2,428	2.9
	NWPE	300	300	--
	RMPA	690	690	--
	SNV	4,634	4,634	--
	SPPS	400	400	2.9
CA-N	CA-S	3,700	3,700	--
	NWPE	150	100	2.9
	PNW	3,675	3,675	2.9
CA-S	AZNM	3,627	2,428	2.9
	CA-N	3,000	2,400	--
	NWPE	1,400	1,400	2.9
	PNW	3,100	3,100	2.9
	SNV	4,688	4,688	2.9
COMD	GWAY	2,050	2,050	2.9
	MRO	825	825	2.9
	RFCO	1,620	1,110	2.9
	RFCP	4,500	788	--
	WUMS	825	825	2.9
DSNY	LILC	1,290	1,290	--
	MACE	2,000	2,000	2.9
	NENG	1,120	1,120	2.9
	NYC	3,700	3,700	--
	UPNY	3,400	3,400	--
ENTG	GWAY	910	140	2.9
	MRO	150	150	2.9
	SOU	2,250	2,250	2.9
	SPPN	1,120	140	2.9
	SPPS	4,494	735	2.9
	TVA	1,681	1,681	2.9
ERCT	ENTG	1,001	1,001	2.9
	SPPS	979	979	2.9
FRCC	SOU	2,000	2,000	2.9
GWAY	COMD	1,100	1,100	2.9
	ENTG	2,804	2,100	2.9
	MRO	405	405	--
	RFCO	6,299	1,848	--
	SPPN	285	285	2.9
	TVA	1,812	1,812	2.9
	TVAK	200	200	2.9
LILC	DSNY	530	530	--
	MACE	650	590	2.9
	NENG	616	616	2.9

From	To	Energy (MW)	Capacity (MW)	Wheeling Charge (mills/kWh)
	NYC	420	420	--
MACE	DSNY	500	500	2.9
	LILC	650	521	2.9
	MACW	2,000	2,000	--
	NYC	1,200	600	2.9
MACS	MACW	3,500	3,000	--
	RFCP	2,500	750	--
	VAPW	2,600	2,600	--
MACW	MACE	6,200	5,800	--
	MACS	5,000	1,350	--
	RFCO	2,208	504	2.9
	RFCP	3,300	2,044	--
	UPNY	1,085	1,085	2.9
MECS	CNON	1,968	1,968	2.9
	RFCO	2,776	1,904	--
	RFCP	3,900	683	2.9
MRO	COMD	610	610	2.9
	CNON	100	100	2.9
	CNSK	165	165	2.9
	ENTG	2,000	2,000	2.9
	GWAY	320	320	--
	NWPE	200	200	2.9
	RMPA	310	310	2.9
	SPPN	1,494	1,494	2.9
	WUMS	800	800	--
NENG	CNNB	1,000	1,000	2.9
	CNPQ	803	803	2.9
	DSNY	980	980	2.9
	LILC	616	473	2.9
NWPE	AZNM	265	265	--
	CA-N	160	120	2.9
	CA-S	1,920	1,920	2.9
	MRO	150	150	2.9
	PNW	2,002	2,002	--
	RMPA	749	749	--
	SNV	300	250	--
NYC	DSNY	1,999	1,999	--
	LILC	175	175	--
PNW	CA-N	4,000	4,000	2.9
	CA-S	3,100	3,100	2.9
	CNBC	2,000	1,000	2.9
	NWPE	1,505	1,505	--
RFCO	COMD	2,760	1,360	2.9
	GWAY	7,078	3,504	--
	MACW	3,100	2,274	2.9
	MECS	4,603	825	--

From	To	Energy (MW)	Capacity (MW)	Wheeling Charge (mills/kWh)
	RFCP	12,908	7,951	2.9
	TVAK	815	270	2.9
RFCP	COMD	3,100	3,100	--
	MACS	2,500	350	--
	MACW	3,900	1,075	--
	MECS	3,700	1,762	2.9
	RFCO	15,041	8,525	2.9
	TVA	1,000	1,000	2.9
	TVAK	1,000	537	2.9
	VACA	3,002	2,042	2.9
	VAPW	3,080	953	--
RMPA	AZNM	690	690	--
	MRO	310	310	2.9
	NWPE	735	735	--
SNV	AZNM	4,785	4,785	--
	CA-S	4,688	4,688	2.9
	NWPE	300	300	--
SOU	ENTG	2,950	2,950	2.9
	FRCC	3,600	3,600	2.9
	TVA	3,742	3,742	2.9
	VACA	1,358	1,358	2.9
SPPN	ENTG	3,745	1,260	2.9
	GWAY	1,200	1,200	2.9
	MRO	600	600	2.9
	SPPS	700	700	--
SPPS	AZNM	400	400	2.9
	ENTG	9,030	2,310	2.9
	ERCT	650	650	2.9
	SPPN	1,200	1,200	--
TVA	ENTG	2,919	2,919	2.9
	GWAY	1,550	1,550	2.9
	RFCP	1,500	263	2.9
	SOU	2,258	2,258	2.9
	TVAK	2,000	1,073	--
	VACA	664	664	2.9
TVAK	GWAY	200	200	2.9
	RFCO	3,365	1,225	2.9
	RFCP	1,000	175	2.9
	TVA	1,500	632	--
UPNY	CNON	2,000	1,325	2.9
	CNPQ	1,000	1,000	2.9
	DSNY	4,550	4,550	--
	MACW	735	735	2.9
	NENG	150	150	2.9
VACA	RFCP	4,117	438	2.9
	SOU	3,242	3,242	2.9
	TVA	3,586	3,586	2.9

From	To	Energy (MW)	Capacity (MW)	Wheeling Charge (mills/kWh)
	VAPW	1,942	1,942	2.9
VAPW	MACS	2,100	2,100	--
	RFCP	5,460	1,952	--
	VACA	1,849	1,849	2.9
WUMS	COMD	1,125	1,125	2.9
	MRO	270	270	--

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 4.10. 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. Wherever available, the maximum values for firm and non-firm TTCs were obtained from public sources. Where public sources were not available, the maximum values for firm and non-firm TTCs are based on ICF's expert view.

It should be noted that each transmission link between model regions shown in Table 3-4 represents 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.

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 developed from the 2004 NERC Summer Assessment and 2004 NERC Winter Assessment. 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 model region is connected to multiple model regions contained in the state of New York, with each link between New England and a New York model region described by its own TTCs. However, there is a maximum limit on the total amount of transfers that the New England region may transfer to the whole of New York, which is represented by the annual joint capacity limit between the New England model region and the relevant New York model regions.

Table 3-5 Annual Joint Capacity and Energy Limits to Transmission Capabilities Between Model Regions in EPA Base Case v.4.10

Region Connections	Transmission Path	Joint Constraint Limit
ECAR to MAAC	RFCO to MACW RFCP to MACS RFCP to MACW	1,385
ECAR to MAIN	RFCO to COMD RFCP to COMD RFCO to GWAY TVAK to GWAY	2,593
ECAR to TVA	TVAK to TVA RFCP to TVA	3,561
ECAR to VACAR	RFCP to VACA RFCP to VAPW	2,022
ENTG to SPP	ENTG to SPPN ENTG to SPPS	338

Region Connections	Transmission Path	Joint Constraint Limit
LILC to NYC & DSNY	LILC to DSNY LILC to NYC	530
MAAC to ECAR	MACS to RFCP MACW to RFCO MACW to RFCP	4,715
MAAC to NPCC	MACE to DSNY MACE to LILC MACE to NYC MACW to UPNY	1,708
MAIN to ECAR	COMD to RFCO COMD to RFCP GWAY to TVAK GWAY to RFCO	3,649
MAIN to MAPP	COMD to MRO GWAY to MRO WUMS to MRO	962
MAPP to MAIN	MRO to COMD MRO to GWAY MRO to WUMS	1,238
MAPP to WECC	MRO to NWPE MRO to RMPA	710
NENG to NY	NENG to DSNY NENG to UPNY NENG to LILC	1,550
NPCC to MAAC	DSNY to MACE LILC to MACE NYC to MACE UPNY to MACW	2,353
NY to NENG	DSNY to NENG LILC to NENG UPNY to NENG	1,750
NYC & DSNY to LILC	DSNY to LILC NYC to LILC	1,465
SPP to ENTG	SPPN to ENTG SPPS to ENTG	1,362
TVA to ECAR	TVA to TVAK TVA to RFCP	1,226
VACAR to ECAR	VACA to RFCP VAPW to RFCP	4,278
WECC to MAPP	NWPE to MRO RMPA to MRO	660

Note:
Source: 2004 NERC Summer Assessment, 2004 NERC Winter Assessment

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 4.10 assumes a wheeling charge of 2.9 mills per kWh for electricity transmission between IPM model regions that fall within different market regions, such as transmission between Northern California and the Pacific Northwest. However, the wheeling charge is not applied to transmission between model regions that are within the same market region, such as transmission between Northern California (model region CA-N) and Southern California (model region CA-S). The wheeling charge applied between IPM model regions can be found in Table 3-4.

3.3.4 Transmission Losses

The EPA Base Case 4.10 assumes a two percent inter-regional transmission loss of energy transferred, in line with EIA's Annual Energy Outlook (AEO) 2010.

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.4.10 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 2010. 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.4.10

	2012	2015	2020	2030	2040	2050
Net Imports from Mexico (billions kWh)	1.57	1.57	1.11	0.89	0.89	0.89

Notes:
Imports & exports transactions from Canada are endogenously modeled in IPM.
Source: AEO 2010

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.4.10 can be found in the National Electrical Energy Data System (NEEDS v.4.10), a database which provides IPM with information on all currently operating and planned-committed electric generating units. NEEDS v.4.10 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 on the unit. In EPA Base Case v.4.10 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.4.10. They are based on data from North American Electric Reliability Council's Generating Availability Data System (NERC GADS) 2001 to 2005 and AEO 2010. Appendix 3-9 shows the availability assumptions for all generating units in EPA Base Case v.4.10.

Table 3-7 Availability Assumptions in the EPA Base Case v.4.10

Unit Type	Annual Availability (%)
Biomass	83
Coal Steam	32 - 95
Combined Cycle	85
Combustion Turbine	89 - 91
Gas/Oil Steam	78 - 92
Geothermal	87
IGCC	85
Pumped Storage	90
Solar	90
Wind	95

Notes:
Values shown are a range of all of the values modeled within the EPA Base Case v.4.10.
Availabilities of coal steam units are based on historical capacity factors.

In the EPA Base Case v.4.10, 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 906 from 2002 through 2006 data. A discussion of capacity factors and generation profiles for wind and solar technologies is contained in section 4.4.5 and Appendices 4-1 and 4-2.

Table 3-8 Seasonal Hydro Capacity Factors (%) in the EPA Base Case v.4.10

Model Region	Winter Capacity Factor	Summer Capacity Factor	Annual Capacity Factor
AZNM	27.4%	32.2%	29.4%
CA-N	36.7%	50.1%	42.3%
CA-S	38.7%	50.4%	43.6%
COMD	40.6%	45.5%	42.6%
DSNY	57.8%	50.2%	54.6%
ENTG	35.4%	32.5%	34.2%
ERCT	13.5%	19.6%	16.1%
FRCC	48.4%	47.4%	48.0%
GWAY	19.2%	22.5%	20.6%
MACE	30.9%	29.2%	30.2%
MACS	14.8%	18.7%	16.4%
MACW	47.5%	33.7%	42.3%
MECS	54.1%	56.9%	55.3%

Model Region	Winter Capacity Factor	Summer Capacity Factor	Annual Capacity Factor
MRO	31.8%	43.7%	36.8%
NENG	44.9%	41.1%	43.3%
NWPE	28.7%	47.6%	36.6%
PNW	40.6%	44.0%	42.0%
RFCO	66.0%	89.2%	75.6%
RFCP	32.7%	30.9%	31.9%
RMPA	18.0%	31.5%	23.7%
SNV	18.0%	23.3%	20.2%
SOU	25.3%	22.1%	24.0%
SPPN	16.5%	17.8%	17.0%
SPPS	21.2%	27.2%	23.7%
TVA	43.2%	37.1%	40.7%
TVAK	32.4%	38.6%	35.0%
UPNY	66.8%	63.1%	65.2%
VACA	23.7%	22.8%	23.3%
VAPW	22.8%	19.0%	21.2%
WUMS	52.6%	57.3%	54.6%

Note:
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.4.10 vary from region to region and over time. Further discussion of the nuclear capacity factor assumptions in EPA Base Case v.4.10 is contained in Section 4.5.

3.5.3 Turndown

Turndown assumptions in EPA Base Case v.4.10 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.4.10 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 International 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. 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.4.10 reserve margin assumptions are shown in Table 3-9.

Table 3-9 Planning Reserve Margins in EPA Base Case v.4.10

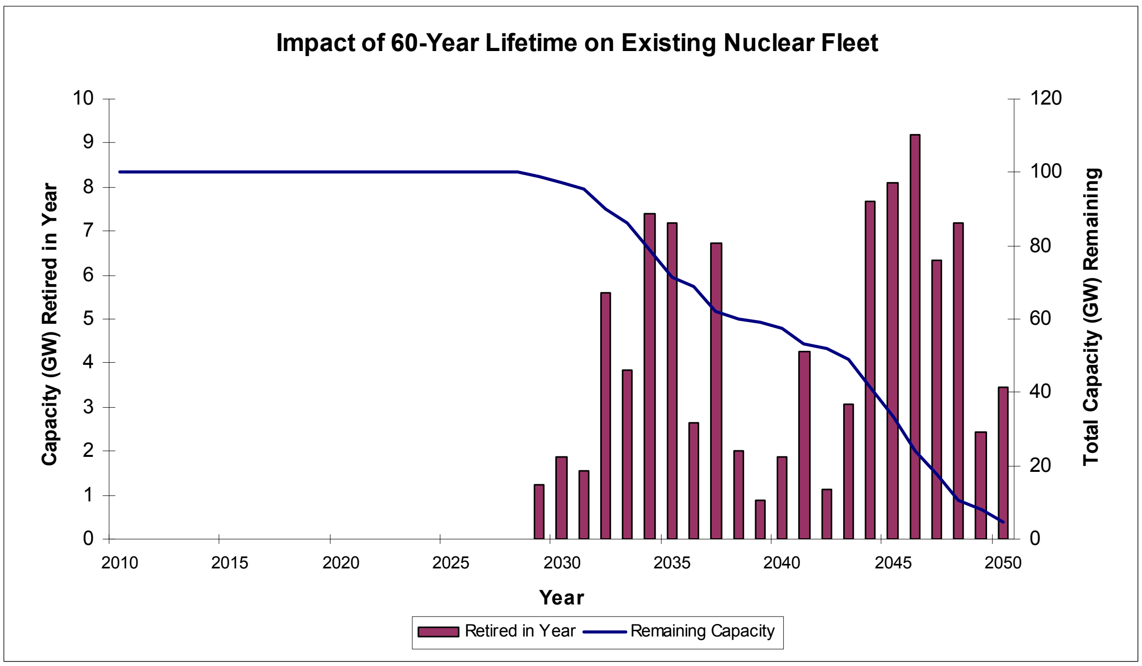
Model Region	Reserve Margin
AZNM	15.7%
CA-N	16.7%
CA-S	16.7%
CNAB	12.8%
CNBC	12.8%
CNMB	15.0%
CNNB	20.0%
CNNF	20.0%
CNNL	20.0%
CNNS	20.0%
CNON	18.3%
CNPE	20.0%
CNPQ	10.0%
CNSK	15.0%
COMD	15.0%
DSNY	16.5%
ENTG	15.0%
ERCT	12.5%
FRCC	15.0%
GWAY	15.0%
LILC	16.5%
MACE	15.0%
MACS	15.0%
MACW	15.0%
MECS	15.0%
MRO	15.0%
NENG	16.0%
NWPE	10.8%
NYC	16.5%
PNW	10.8%
RFCO	15.0%
RFCP	15.0%
RMPA	14.3%
SNV	15.7%
SOU	15.0%
SPPN	13.6%
SPPS	13.6%
TVA	12.0%
TVAK	15.0%
UPNY	16.5%
VACA	15.0%
VAPW	15.0%
WUMS	16.0%

3.7 Power Plant Lifetimes

EPA Base Case v.4.10 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 for economic reasons. Other types of units are not provided an economic retirement option.

Nuclear Retirement at Age 60: Existing nuclear units are forced to retire in EPA Base Case v.4.10 at the completion of age 60. Today's nuclear fleet totals more than 100 GW. A 60-year lifetime 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 represented in EPA Base Case v.4.10, including their online year and other characteristics, see Appendix 4-3.

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



The 60-year lifetime assumption is based on several factors. At the time that this base case was prepared there were many instances of the U.S. Nuclear Regulatory Commission (NRC) granting license extensions of 20 years beyond the initial 40 year operating licenses authorized by the NRC for commercial nuclear power plants under the Atomic Energy Act of 1954. At the time of the release of EPA Base Case v.4.10, the NRC had granted license renewals to 50 operating reactors allowing them to operate for 60 years with fifteen additional applications under review and the owners of 21 other units announcing their intention to file for 20-year license extensions. All of these applications would allow the units to operate to age 60.

At the same time, there were no units in the U.S. nuclear fleet licensed to operate past age 60[9]. In keeping with the practice of the EPA base case representing legal provisions that are on the books or immediately pending, a conservative approach was adopted of reflecting the current maximum licensing period of 60 years for the nuclear units in EPA Base Case v.4.10.

Another factor in the decision to implement the 60-year nuclear life assumption is the degree of uncertainty surrounding nuclear life extensions past age 60. As noted in EIA's review of the 60 year nuclear life question, uncertainties include:

- The absence, to date, of publicly available plans and cost estimates for potential major capital expenditures involved with extensions to age 80 such as the replacement of reactor vessels, containment structures, or buried piping and cables.
- Possible future additional regulatory requirements which could result in expensive upgrades at nuclear power plants and figure into life extension decisions. Among those mentioned in EIA's review was a rule that was recently the subject of the Supreme Court case Entergy Corp v. Riverkeeper10, which focused on whether or not the EPA could conduct cost-benefit analyses to determine whether a plant needed to replace open-cycle cooling water systems with closed-cycle systems.

The assumption of nuclear retirements at age 60 in EPA Base Case v.4.10 contrasts to a certain degree with the assumption made in AEO 2010. Due to AEO 2010's shorter time horizon compared to the EPA base case (i.e., 2035 compared to 2050), EIA did not have to explicitly adopt an 80 year nuclear life assumption (as would have been necessary in EPA Base Case v.4.10), only that "the operating lives of existing nuclear power plants would be extended at least through 2035.[11]" The basis for the decision appears to be that "The nuclear industry has expressed strong interest in continuing the operation of existing nuclear facilities, and no particular technical issues have been identified that would impede their continued operation.[12]"

Although the adopted assumptions differ in EPA Base Case v.4.10 and AEO 2010, there is agreement on the importance of performing side cases using the alternative assumptions. In the case of EPA Base Case v.4.10 this will mean performing sensitivity analysis runs with an 80 nuclear lifetime assumption.

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[9] The Energy Information Administration has an excellent review and summary of the issues involved in the 60 year nuclear life question. Although EPA's base case does not adopt the same assumption as AEO 2010, the text in this section relied heavily on the EIA review. With respect to the status of applications for renewals beyond age 60, the EIA review notes the following: "In December 2009, the Oyster Creek Generating Station in Lacey Township, New Jersey, became the first nuclear power plant in the United States to begin its 40th year of operation. With Oyster Creek and other nuclear plants of similar vintage just beginning to enter their first period of license renewal, it probably will be at least 5 to 10 years before there is any clear indication as to whether plant operators will be likely to seek further extensions of their plants' operating lives." The EIA review also observes ". . . the NRC and the nuclear power industry are preparing applications for license renewals that would allow continued operation beyond 60 years, the first of which is scheduled to be submitted by 2013. In February 2008, DOE and the NRC hosted a joint workshop titled "Life Beyond 60," with a broad group of nuclear industry stakeholders meeting to discuss this issue. The workshop's summary report outlined many of the technical research needs that participants agreed were important to extending the life of the existing fleet of U.S. nuclear plants." Energy Information Administration (EIA), U.S. Department of Energy, "U.S. nuclear power plants: Continued life or replacement after 60?" *Annual Energy Outlook 2010 with Projections to 2035* (DOE/EIA-0383(2010)), May 11, 2010, www.eia.doe.gov/oiaf/aeo/nuclear_power.html.

[10] Supreme Court of the United States, "Entergy Corp. v. Riverkeeper, Inc., et al.," No. 07-588 (October Term, 2008 www.supremecourtus.gov/opinions/ 08pdf/07-588.pdf.

[11] EIA, op.cit.

[12] EIA, ibid.

3.8 Heat Rates

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.4.10 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.4.10 are based on values from AEO 2008. These values were screened and adjusted using a procedure developed by EPA to ensure that the heat rates used in EPA Base Case v.4.10 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.4.10

Plant Type	Heat Rate (Btu/kWh)	
	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 and above	8,700	18,700
Combustion Turbine - Natural Gas < 80 MW	8,700	36,800
Combustion Turbine - Oil and Oil/Gas - 80 MW and above	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, and CO_2 emissions regulations that are represented in the EPA Base Case v.4.10. The first three 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.

Note on Clean Air Interstate Rule (CAIR): In December 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. Until EPA's work was completed, CAIR, which includes a cap-and-trade system for SO_2 and NO_x emissions, was temporarily reinstated. However, although CAIR's provisions were still in effect when EPA Base Case v.4.10 was released, it is not included in the base case to allow EPA Base Case v.4.10 to be used to analyze the regulations proposed to replace CAIR.

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.4.10. 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.4.10 there are 6 different sulfur grades of bituminous coal, 3 different grades of sub-bituminous coal, 3 different grades of lignite, and 1 sulfur grade of residual fuel oil. There are 2 different SO_2 scrubber options 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.4.10 is the SO_2 allowance trading 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.4.10 reflect the provisions in Title IV. Since EPA Base Case v.4.10 uses year 2012 as the first analysis year, a projection of allowance banking behavior through the end of 2011 and specification of the available 2012 allowances are needed to initialize the modeling. EPA developed the projection of the banked allowances (11 million) going into 2012. Calculating the available 2012 allowances involved deducting allowance surrenders due to NSR settlements and state regulations from the 2012 SO_2 cap of 8.95 million tons. The surrenders totaled 270.6 thousand tons in allowances, leaving 8.679 million of 2012 allowances remaining. Table 7-4 shows the initial bank and 2012 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 Appendices 3-2 and 3-3.

EPA Base Case v.4.10 also includes a representation of the Western Regional Air Partnership (WRAP) Program, a regional initiative involving Arizona, New Mexico, Oregon, Utah, 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.4.10 through a combination of system level NO_x programs and generation unit-level NO_x limits.

The system level NO_x regulation represented in EPA Base Case v.4.10 is the NO_x SIP Call trading program. This trading program affects all fossil units in 20 northeastern states[13] and the District of Columbia. The program is only in effect during the ozone season (May - September). The program includes state-specific NO_x budgets. However, since the program allows for trading among units in different states, the total annual NO_X SIP Call budget of 527,580 tons is used in EPA Base Case v.4.10, rather than the state-specific budgets. The specifications for the SIP Call are presented in Table 7-4.

[13]The states included in the SIP Call program are Alabama, Connecticut, Delaware, Illinois, Indiana, Kentucky, Maryland, Massachusetts, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, and West Virginia.

The representation of unit-level NO_x limits includes Title IV unit specific rate limits and Clean Air Act Reasonable 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[14] (OTR). Both of these limits are captured in the specific NO_x emission rates assigned to each unit represented in the base case. 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.4.10 the NO_x emission rate of a unit can only change if the unit is retrofitted with NO_x pollution control equipment.

NO_x Rates in NEEDS, v.4.10 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 2007. The emission rates themselves reflect the impact of the 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 policy affecting that unit in a model run.

The reason for having four NO_x rates in NEEDS is to allow all possible modeling scenarios involving NO_x controls to be set up. The four NO_x rates are designated as Mode 1–4, and are designed to include all the NO_x rates possible for a unit with its current configuration of NO_x combustion and post-combustion controls. The four NO_x rates are:

- **Mode 1:** Applies to units not covered by a NO_X control policy. Specifically, this is the NO_X rate with post-combustion controls shut off. For units without post-combustion controls, it's their uncontrolled NO_X rate.
- **Mode 2:** A unit, which has post-combustion controls, runs them, but a unit without post-combustion controls operates as usual.
- **Mode 3:** Applies to the off-season NO_X rate for units affected by a seasonal NO_X policy. For units with post-combustion controls, this is the NO_X rate with post-combustion controls shut off. For units without post-combustion controls, it's the NO_X rate with state-of-the-art combustion controls operating. (Exception: In the SIP Call region current combustion controls are assumed to be retained.)
- **Mode 4:** NO_X rate applicable under a NO_X policy. For SCR units, it's the NO_X rate with the SCR operating. For SNCR units, it's the NO_X rate with SNCR operating plus state-of-the-art combustion controls operating if required to attain rate limits. For units without post-combustion controls, it's the NO_X rate with state-of-the-art combustion controls operating. (Exception: In the SIP Call region current combustion controls are assumed to be retained.)

The program that sets up a new model run uses a series of algorithms (decision rules) to determine which of the four NO_X rates is selected:

- A unit covered under an annual NO_X emission limit is assigned the Mode 4 NO_X rate (winter and summer seasons).
- A unit covered by a summer season NO_X emission limit, but not an annual NO_X limit, is assigned the Mode 4 NO_X rate in the summer season but the Mode 3 NO_X rate in the winter season.
- A unit covered by a mercury emission limit and not by a NO_X emission limit is assigned the Mode 2 NO_X rate in both winter and summer seasons. (Note: In the case of mercury limits, Mode 2 applies since it implies operation of an SCR or SNCR. This equipment, in combination with SO_2 and particulate controls, offers as a co-benefit the reduction and capture

[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.

of mercury. See Chapter 5 in the v.4.10 documentation for a discussion of the calculation mercury emission modification factors (EMF).)

- A unit not covered by either an annual or a summer NO_X limit nor mercury control requirements is assigned the Mode 1 NO_X rate in both winter and summer seasons.

The Mode 1-4 NO_x rates for each generating unit are included in the NEEDS, v.4.10 database, described in Chapter 4. Appendix 3-1 and accompanying Tables 3-1.1, 3-1.2, and 3-1.3 give further information on the procedures employed to derive the four NO_X rate modes and give specific examples of generating units that fit each of the Mode 1-4 specifications.

Additional NO_X rate assumptions include default NO_X rates of 0.25 lbs/MMBtu for existing biomass units and 0.09 lbs/MMBtu for existing landfill gas units.

3.9.3 CO_2 Regulations and Renewable Portfolio Standards

The Regional Greenhouse Gas Initiative (RGGI) is a year-round CO_2 cap and trade program affecting fossil fired electric power plants 25 MW or larger in Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, Vermont, Rhode Island, Massachusetts, and Maryland. Table 7-4 shows the specifications for RGGI that are implemented in EPA Base Case v.4.10.

Renewable Portfolio Standards (RPS) generally refer 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.4.10 the state RPS requirements are represented at a regional level utilizing the aggregate regional representation of RPS requirements that is implemented in AEO 2010[15] as shown in Appendix 3-6. This appendix shows the RPS requirements that apply to the NEMS (National Energy Modeling System) regions used in AEO. The RPS requirement for a particular NEMS region applies to all IPM regions that are predominantly contained in that NEMS region.

3.9.4 State Specific Environmental Regulations

EPA Base Case v.4.10 represents laws and regulations in 25 states affecting emissions from the electricity sector. The laws and regulations had to either be on the books or expected to come into force. Appendix 3-2 summarizes the provisions of state laws and regulations that are represented in EPA Base Case 4.10.

3.9.5 New Source Review (NSR) Settlements

The 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.4.10 includes NSR settlements with 20 electric power companies. A summary of the units affected and how the settlements were modeled can be found in Appendix 3-3.

Seven state settlements and five citizen settlements are also represented in EPA Base Case v.4.10. These are summarized in Appendices 3-4 and 3-5 respectively.

3.9.6 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 on line in each model region. Across all model regions the emission and removal

[15] Energy Information Administration, U.S. Department of Energy, *Assumptions to Annual Energy Outlook 2010: Renewable Fuels Module* (DOE/EIA-0554(2010)), April 9, 2010, Table 13.4 “Aggregate Regional RPS Requirements, www.eia.doe.gov/oiaf/aeo/assumption/renewable.html and www.eia.doe.gov/oiaf/aeo/assumption/pdf/renewable_tbls.pdf

rate capabilities of potential new units are the same. It should be noted that, new coal units cannot be built in the CA-N, CA-S, NYC, LILC, or NENG model regions due to particularly stringent state emission limits placed on fossil fired units. The specific assumptions regarding the emission and removal rates of potential new units in EPA Base Case v.4.10 are presented in Table 3-11. (Note: Nuclear, wind, solar, and fuel cell technologies are not included in Table 3-11 because they do not emit any of the listed pollutants.) For additional details on the modeling of potential new units see Chapter 4.

3.10 Capacity Deployment Constraints

Due to its extended time horizon and the policies that EPA Base Case v.4.10 is expected to be used to analyze, capacity deployment constraints for the more capital intensive generation technologies and retrofits (new nuclear, advanced coal with carbon capture, and carbon capture retrofits) were incorporated into the base case. 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 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.

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.

Appendix 3-07 shows the joint capacity deployment constraint on advanced coal with carbon capture and storage (CCS) and new nuclear. Appendix 3-08 shows the capacity deployment constraint on new nuclear in itself. The bar graph in Appendix 3-08 illustrates how building capacity in earlier years increases the maximum capacity that can be built over the entire modeling time horizon.

Table 3-11 Emission and Removal Rate Assumptions for Potential (New) Units in EPA Base Case v.4.10

Gas	Controls, Removal, and Emissions Rates	Supercritical Pulverized Coal - Wet Scrubber	Supercritical Pulverized Coal - Dry Scrubber	Integrated Gasification Combined Cycle	Advanced Coal with Carbon Capture	Advanced Combined Cycle	Advanced Combustion Turbine	Biomass Conventional Direct-Fired Boiler	Biomass Gasification Combined Cycle	Geothermal	Landfill Gas
SO_2	Removal / Emissions Rate	98% with a floor of 0.06 lbs/MMBtu	93% with a floor of 0.065 lbs/MMBtu	99%	99%	None	None	0.08 lbs/MMBtu	0.08 lbs/MMBtu	None	None
NO_x	Emission Rate	0.06 lbs/MMBtu	0.06 lbs/MMBtu	0.013 lbs/MMBtu	0.013 lbs/MMBtu	0.011 lbs/MMBtu	0.011 lbs/MMBtu	0.36 lbs/MMBtu	0.102 lbs/MMBtu	None	0.09 lbs/MMBtu
Hg	Removal / Emissions Rate	90%	90%	90%	90%	Natural Gas: 0.000138 lbs/MMBtu Oil: 0.483 lbs/MMBtu	Natural Gas: .000138 lbs/MMBtu Oil: 0.483 lbs/MMBtu	0.57 lbs/MMBtu	0.57 lbs/MMBtu	3.70	None
CO_2	Removal / Emissions Rate	205.2 - 217.3 lbs/MMBtu	205.2 - 217.3 lbs/MMBtu	205.2 - 217.3 lbs/MMBtu	90%	Natural Gas: 117.08 lbs/MMBtu Oil: 161.39 lbs/MMBtu	Natural Gas: 117.08 lbs/MMBtu Oil: 161.39 lbs/MMBtu	None	None	None	None

Appendix 3-1 NO_x Rate Development in EPA Base Case v.4.10

The following questions (Q) and answers (A) are intended to provide further background on the four NO_X rates found in the NEEDS, v.4.10 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 policies 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 policy 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:

Mode 1= Uncontrolled Base Rate
Mode 2= Controlled Base Rate
Mode 3= Uncontrolled Policy Rate
Mode 4 = Controlled Policy Rate

The operational states associated with each of the four NO_x rates are shown in the second and third columns in the table below.

Q3: What NO_x policies in a model run result in the assignment of each of the NO_x rates?

A3: The policies causing each rate to be assigned are shown in the last column in the table below.

Interpreting the Mode 1 – 4 NO_x Rates in NEEDS

Name	Operational State of NO_x Controls		NO_x Policies Causing This Rate To be Assigned
Mode 1 = Uncontrolled Base Rate	Units with post combustion NO_x controls: Do they operate the controls?	No	If the unit is not covered by any NO_x limit in the run, pre-assign this as its NO_x rate
	Units without post-combustion controls: Do they upgrade to state-off-the-art combustion controls?	No	
Mode 2 = Controlled Base Rate	Units with post combustion NO_x controls: Do they operate the controls?	Yes	If the unit is covered by a mercury policy, pre-assign this as its NO_x rate Explanation: Post-combustion NO_x controls figure in mercury reduction but NO_x combustion controls do not, so the operational state (in column 2) fits the requirements of the policy
	Units without post-combustion controls: Do they upgrade to state-off-the-art combustion controls?	No	
Mode 3 = Uncontrolled Policy Rate	Units with post combustion NO_x controls: Do they operate the controls?	No	If the unit is covered by a summer NO_x limit pre-assign this as its winter NO_x rate.
	Units without post-combustion controls: Do they upgrade to state-off-	Yes	

Name	Operational State of NO_x Controls		NO_x Policies Causing This Rate To be Assigned
	the-art combustion controls?		
Mode 4 = Controlled Policy Rate	Units with post combustion NO_x controls: Do they operate the controls?	Yes	If the unit is covered by a summer NO_x limit pre-assign this as its summer NO_x rate. If the unit is covered by an annual NO_x limit, pre-assign this as its winter and summer NO_x rates.
	Units without post-combustion controls: Do they upgrade to state-off-the-art combustion controls?	Yes	

Q4: How are the values of the Mode 1-4 NO_x rates derived?

A4: 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 them is beyond the scope of this illustration. Basically, here's how the values would be derived:

<u>Mode 1</u>
For all coal units Mode 1 = Winter NO_x rate

<u>Mode 2</u>
<u>For coal units without NO_x post-combustion controls</u>
Mode 2 = Mode 1 rate

<u>For coal units with NO_x post-combustion controls</u>,

Min{max[Mode 1 NO_x rate * (1-removal efficiency), floor rate], ETS Summer NO_x rate}

Where

<u>For an SCR</u>,
Removal efficiency = 90%
Floor rate = 0.06 lb/MMBtu;
<u>For an SNCR</u>,
Removal efficiency = 35%
No floor rate is applicable

<u>Mode 3</u>
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

<u>For coal units without post-combustion NO_x controls</u>

<u>For units listed as not having combustion controls</u>
Make sure their NO_x rates do not indicate that they really do have SOA control
If Mode 1 > Cut-off (in Table 3-1.2), then Mode 1 = Base rate. Go to Step 3
If Mode 1 ≤ Cut-off (in Table 3-1.2), then the unit has SOA control and
Go to Step 5 using the Mode 1 rate as the provisional SOA NO_x rate.

<u>For coal listed with combustion controls</u>
If Mode 1 > Cut-off (in Table 3-1.2), then unit has non-SOA combustion controls.
Go to Step 2

If Mode 1 ≤ Cut-off (in Table 3-1.2), then the unit has SOA control and
Go to Step 5 using the Mode 1 rate as the provisional SOA NO_x rate.

For coal units with post-combustion NO_x controls

For coal units with SCR
Mode 1 = Mode 3

For coal units with SNCR
If Mode 1 ≤ Cut-off (in Table 3-1.2), then the unit has SOA control and
Mode 1 = Mode 3
If Mode 1 > Cut-off (in Table 3-1.2), then unit has non-SOA combustion controls.
Go to Step 2

Step 2: For units with non-SOA combustion controls, determine their 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 3-1.3 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 3.

Step 3: Use the appropriate equations (in boldface italics) in Table 3-1.3 to calculate the NO_x rate with SOA combustion controls.

Step 4: Compare the value calculated in Step 3 to the applicable NO_x floor rate in Table 3-1:2.

For units with post-combustion controls
If the value from Step 3 is ≥ floor, use the Step 3 value as Mode 3 NO_x rate. Otherwise, use the floor as the Mode 3 NO_x rate.

For units without post-combustion controls
If the value from Step 3 is ≥ floor, use the Step 3 value as the provisional SOA NO_x rate. Otherwise, use the floor as their provisional SOA NO_x rate.
Go to Step 5.

Step 5: For units without post combustion controls compare the provisional SOA NO_x rate obtained in previous steps to their Summer NO_x rate.
If Summer NO_x rate < provisional SOA NO_x rate, then Mode 3 = summer NO_x rate.
If Summer NO_x rate ≥ provisional SOA NO_x rate, then
Mode 3 = provisional SOA NO_x rate.

Mode 4

For units without post-combustion controls
Mode 4 = Mode 3

For units with SCR post-combustion controls
Mode 4 = Mode 2

For units with SNCR post-combustion controls
Mode 4 = minimum {(1-.35) * Mode 3, Summer NO_x rate}

Note: The (1-.35) term in the equation above represents the 35% NO_x removal efficiency of SNCR.

Q5: Is there anything else that might be useful to understand about the Mode 1 – 4 NO_x rates.

A5: There are several things to note about the Modes 1-4 designations. “Controlled” refers to the rates provided by post combustion NO_x controls, i.e., selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR), if they are present at the unit. For generating units that do not have post-combustion controls, the controlled rate will be the same as the uncontrolled rate. For generating units that do have post-combustion controls, the controlled and uncontrolled rates will differ. Base and Policy NO_x rates will be same if the unit has state-of-the-art NO_x combustion controls or is in the SIP Call region where current combustion controls are assumed to be retained. Base and policy rates will differ if a unit does not currently have state-of-the-art combustion controls that would be installed in response to a NO_x policy. Examples of each of these instances are shown in Table 3-1.1.

Other things worth noting are:
(a) In general, winter NO_x rates reported in EPA’s Emission Tracking System were used as proxies for the uncontrolled base NO_x rates.
(b) If a unit does not report having combustion controls, but has an emission rate below a specific cut-off rate (shown in Table 3-1.2), it is considered to have combustion controls.
(c) For units with combustion controls that were not state-of-the-art, emission rates without those combustion controls were back-calculated and then policy rates were derived assuming the reductions provided by state-of-the art combustion controls.
(d) The NO_x rates achievable by state-of-the-art combustion controls vary by coal rank (bituminous and sub-bituminous) and boiler type. The equations used to derive these rates are shown in Table 3-1.3.

Q6: What are examples of the Mode 1-4 NO_x for some actual operating generating units?

A6: Table 3-1.1 gives the Mode 1-4 NO_x rates for real generating units. They are meant to illustrate a range of situations that can arise.

Table 3-1.1 Examples of Base and Policy NO_x Rates Occurring in EPA Base Case v.4.10

<table>
<tr><th>Plant Name</th><th>Unique ID</th><th>Post-Combustion Control</th><th>Uncontrolled NO_x Base Rate</th><th>Controlled NO_x Base Rate</th><th>Uncontrolled NO_x Policy Rate</th><th>Controlled NO_x Policy Rate</th><th>Explanation</th></tr>
<tr><td colspan="8">Situation 1: For generating units that do not have post-combustion controls, the controlled and uncontrolled rates will be the same.</td></tr>
<tr><td>Four Corners</td><td>2442_B_1</td><td>None</td><td>0.809</td><td>0.809</td><td>0.524</td><td>0.524</td><td>Situation 4 also applies, i.e., unit had LNB and now added OFA so see drop in policy rates.</td></tr>
<tr><td colspan="8">Situation 2: For generating units that do have post-combustion controls, the controlled and uncontrolled rates will differ.</td></tr>
<tr><td>Big Sandy</td><td>1353_B_BSU2</td><td>SCR</td><td>0.638</td><td>0.064</td><td>0.638</td><td>0.064</td><td>(1) Has SCR so see difference between uncontrolled and controlled rates
(2) Situation 3b also applies.</td></tr>
<tr><td colspan="8">Situation 3a: Base and Policy NO_x rates will be same if the unit has state-of-the-art NO_x combustion controls or . . .</td></tr>
<tr><td>Greene County</td><td>10_B_2</td><td>None</td><td>0.316</td><td>0.316</td><td>0.316</td><td>0.316</td><td>Situation 1 also applies.</td></tr>
<tr><td>Roxboro</td><td>2712_B_1</td><td>SCR</td><td>0.900</td><td>0.084</td><td>0.900</td><td>0.084</td><td>Situation 2 also applies.</td></tr>
<tr><td colspan="8">Situation 3b: . . . is in the SIP Call region where current combustion controls are assumed to be retained.</td></tr>
<tr><td>Thomas Hill</td><td>2168_B_MB3</td><td>SCR</td><td>0.223</td><td>0.060</td><td>0.223</td><td>0.060</td><td>Situation 2 also applies.</td></tr>
<tr><td>Waukegan</td><td>883_B_17</td><td>None</td><td>0.710</td><td>0.710</td><td>0.710</td><td>0.710</td><td>(1) Has NO_x combustion control and is in SIP so doesn't get added combustion control. High NO_x rate because it is a cyclone unit
(2) Situation 1 also applies.</td></tr>
<tr><td colspan="8">Situation 4: Base and policy rates will differ if a unit does not currently have state-of-the-art combustion controls and would install such controls in response to a NO_x policy.</td></tr>
<tr><td>Clay Boswell</td><td>1893_B_4</td><td>SNCR</td><td>0.231</td><td>0.150</td><td>0.152</td><td>0.099</td><td>(1) Drop in uncontrolled policy NO_x rate compared to uncontrolled base rate is due to addition of combustion controls. (Note 0.32 is floor.)
(2) Unit has SNCR so Situation #2a also applies and you see a 35% drop between uncontrolled and controlled NO_x rates.</td></tr>
</table>

Table 3-1.2 Cutoff and Floor NO_x Rates (lb/MMBtu) in EPA Base Case v.4.10

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 3-1.3 NO_x Removal Efficiencies for Different Combustion Control Configurations in EPA Base Case v.4.10

(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

Appendix 3-2 State Power Sector Regulations included in EPA Base Case v.4.10

State/ Region	Bill	Emission Type	Emission Specifications	Implementation Status
Alabama	Alabama Administrative Code Chapter 335-3-8	NO_x	0.02 lbs/MMBtu annual PPMDV for combined cycle EGUs which commenced operation after April 1, 2003	2003
Arizona	Title 18, Chapter 2, Article 7	Hg	90% removal of Hg content of fuel or 0.0087 lb/GWH-hr 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
		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)	
Colorado	40 C.F.R. Part 60	Hg	2012 & 2013: 80% reduction of Hg content of fuel or 0.0174 lb/GW-hr annual reduction for Pawnee Station 1 and Rawhide Station 101 2014 through 2016: 80% reduction of Hg content of fuel or 0.0174 lb/GW-hr annual reduction for all coal units > 25 MW 2017 onwards: 90% reduction of Hg content of fuel or 0.0087 lb/GW-hr annual reduction for all coal units > 25 MW	2012
Connecticut	Executive Order 19 and Regulations of Connecticut State Agencies (RCSA) 22a-174-22	NO_x	0.15 lbs/MMBtu annual rate limit for all fossil units > 15 MW	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 > 15 MW	
	Public Act No. 03-72 & RCSA 22a-198	Hg	90% removal of Hg content of fuel or 0.0087 lb/GW-hr 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
		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
		Hg	2012: 80% removal of Hg content of fuel or 0.0174 lb/GW-hr annual reduction for all coal units > 25 MW 2013 onwards: 90% removal of Hg content of fuel or 0.0087 lb/GW-hr annual reduction for all coal units > 25 MW	
Georgia	Multipollutant Control for Electric Utility Steam Generating Units	SCR, FGD, and Sorbent Injection Baghouse controls to be installed	The following plants must install controls: Bowen, Branch, Hammond, McDonough, Scherer, Wansley, and Yates	Implementation from 2008 through 2015, depending on plant and control type
Illinois	Title 35, Section 217.706	NO_x	0.25 lbs/MMBtu summer season rate limit for all fossil units > 25 MW	2004
	Title 35, Part 225, Subpart B: Control of Hg Emissions from Coal Fired Electric Generation Units	NO_x	0.11 lbs/MMBtu annual rate limit and ozone season rate limit for all Dynergy and Ameren coal steam units > 25 MW	2012
		SO_2	2013 & 2014: 0.33 lbs/MMBtu annual rate limit for all Dynergy and Ameren coal steam units > 25 MW 2015 onwards: 0.25 lbs/MMBtu annual rate limit for all Dynergy and Ameren coal steam units > 25 MW	2013
		Hg	90% removal of Hg content of fuel or 0.08 lbs/GW-hr annual reduction for all Ameren and Dynergy coal units > 25 MW	2015
	Title 35 Part 225; Subpart F: Combined Pollutant Standards	NO_x	0.11 lbs/MMBtu ozone season and annual rate limit for all specified Midwest Gen coal steam units	2012
		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
Louisiana	Title 33 Part II - Chapter 22, Control of Nitrogen Oxides	NO_x	1.2 lbs/MMBtu ozone season PPMDV for all single point sources that emit or have the potential to emit 5 tons or more of SO_2 into the atmosphere	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
	Statue 585-B Title 38, Chapter 4: Protection and Improvement of Air	Hg	25 lbs annual cap for any facility including EGUs	2010

State/ Region	Bill	Emission Type	Emission Specifications	Implementation Status
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 Bayton Point, Mystic Generating Station, Somerset Station, Mount Tom, Canal, and Salem Harbor	2006
		SO_2	3.0 lbs/MWh annual GPS for Bayton Point, Mystic Generating Station, Somerset 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, Somerset Station, Mount Tom, Canal, and Salem Harbor 2013 onwards: 95% removal of Hg content of fuel or 0.00000250 lbs/MWh annual GPS for Brayton Point, Mystic Generating Station, Somerset Station, Mount Tom, Canal, and Salem Harbor	
Michigan	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 units > 250 MW	2008
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

State/ Region	Bill	Emission Type	Emission Specifications	Implementation Status
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	
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 95% removal of Hg content of fuel annually for all MSW incinerator units	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 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 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 4	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
New York	Part 237	NO_x	39.91 MTons non-ozone season cap for fossil fuel units > 25 MW	2004
	Part 238	SO_2	131.36 MTons 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
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 >25MW 2013 onwards: 50 MTons annual cap for Progress Energy coal plants > 25 MW and 80	2009

State/ Region	Bill	Emission Type	Emission Specifications	Implementation Status
			MTons annual cap for Duke Energy coal plants > 25 MW	
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 rate limit for all potential coal units > 25 MW	2009
Pacific Northwest	Washington State House Bill 3141	CO_2	$1.45/Mton cost (2004$) for all new fossil-fuel power plant	2004
Texas	Senate Bill 7 Chapter 101	SO_2	273.95 MTons cap of SO_2 for all grandfathered units built before 1971 in East Texas Region	2003
		NO_x	Annual cap for all grandfathered units built before 1971 in MTons: 84.48 in East Texas, 18.10 in West Texas, 1.06 in El Paso Region	
	Chapter 117	NO_x	East and Central Texas annual rate limits in lbs/MMBtu for units that came online before 1996: Gas fired units: 0.14 Coal fired units: 0.165 Stationary gas turbines: 0.14	2007
			Dallas/Fort Worth Area annual rate limit for utility boilers, auxiliary steam boilers, stationary gas turbines, and duct burners used in an electric power generating system except for CT and CC units online after 1992: 0.033 lbs/MMBtu or 0.50 lbs/MWh output or 0.0033 lbs/MMBtu on system wide heat input weighted average for large utility systems 0.06 lbs/MMBtu for small utility systems	
			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
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: 2009: 0.15, 2013 onwards: 0.10 Arch fired: 2009 onwards: 0.18	2009

State/ Region	Bill	Emission Type	Emission Specifications	Implementation Status
			Annual rate limits in lbs/MMBtu for coal fired boilers between 500 and 1,000 MMBtu/hr: Wall fired: 2009: 0.20; 2013 onwards: 0.17 in 2013 Tangential fired: 2009 onwards: 0.15 Cyclone fired: 2009: 0.20; 2013 onwards: 0.15 Fluidized bed: 2009: 0.15; 2013 onwards: 0.10 Arch fired: 2009 onwards: 0.18	
			Annual rate limits for CTs in lbs/MMBtu: Natural gas CTs > 50 MW: 0.11 Distillate oil CTs > 50 MW: 0.28 Biologically derived fuel CTs > 50 MW: 0.15 Natural gas CTs between 25 and 49 MW: 0.19 Distillate oil CTs between 25 and 49 MW: 0.41 Biologically derived fuel CTs between 25 and 49 MW: 0.15	
			Annual rate limits for CCs in lbs/MMBtu: Natural gas CCs > 25 MW: 0.04 Distillate oil CCs > 25 MW: 0.18 Biologically derived fuel CCs > 25 MWs: 0.15 Natural gas CCs between 10 and 24 MW: 0.19	
	Chapter NR 446. Control of Mercury Emissions	Hg	2012 through 2014: 40% reduction in total Hg emissions for all coal-fired units in electric utilities with annual Hg emissions > 100 lbs 2015 onwards: 90% removal of Hg content of fuel or 0.0080 lbs/GW-hr reduction in coal fired EGUs > 150 MW 80% removal of Hg content of fuel or 0.0080 lbs/GW-hr reduction in coal fired EGUs > 25 MW	2010

Appendix 3-3 New Source Review (NSR) Settlements in EPA Base Case v.4.10

Company and Plant	State	Unit	Settlement Actions														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	
Alabama Power																	
James H. Miller	Alabama	Units 3 & 4			Install and operate FGD continuously	95%	12/31/2011	Operate existing SCR continuously	0.1	5/1/2008		0.03	12/31/2006	With 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	1/1/2021	http://www.epa.gov/compliance/resources/cases/civil/caa/alabamapower.html
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	Minnesota	Unit 1			Install and continuously operate FGD	95% if wet FGD, 90% if dry	12/31/2011	Install and continuously operate Over-fire AIR, or equivalent technology with emission rate < .36	0.36	12/31/2009		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		http://www.epa.gov/compliance/resources/cases/civil/caa/minnkota.html
		Unit 2			Design, upgrade, and continuously operate FGD	90%	12/31/2010	Install and continuously operate over-fire AIR, or equivalent technology with emission rate < .36	0.36	12/31/2007		0.03	Before 2008				
SIGECO																	
FB Culley	Indiana	Unit 1	Repower to natural gas (or retire)	12/31/2006										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://www.epa.gov/compliance/resources/cases/civil/caa/sigecofb.html

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	Reference
		Unit 2			Improve and continuously operate existing FGD (shared by Units 2 and 3)	95%	6/30/2004										
		Unit 3			Improve and continuously operate existing FGD (shared by Units 2 and 3)	95%	6/30/2004	Operate Existing SCR Continuously	0.1	9/1/2003	Install and continuously operate a Baghouse	0.015	6/30/2007				
PSEG FOSSIL																	
Bergen	New Jersey	Unit 2	Repower to combined cycle	12/31/2002										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://www.epa.gov/compliance/resources/cases/civil/caa/pseglIc.html
Hudson	New Jersey	Unit 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/2006	Install SCR (or approved tech) and continually operate	0.1	5/1/2007	Install Baghouse (or approved technology)	0.015	12/31/2006				
Mercer	New Jersey	Units 1 & 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/2010	Install SCR (or approved tech) and continually operate	0.13	5/1/2006							
TECO																	
Big Bend	Florida	Units 1 & 2			Existing Scrubber (shared by Units 1 & 2)	95% (95% or .25)	09/1/00 (01/01/13)	Install SCR	0.1	5/1/2009				The provision did not specify an amount of SO_2 allowances to be surrendered. It only provided that excess allowances resulting			http://www.epa.gov/compliance/resources/cases/civil/caa/teco.html
		Unit 3			Existing Scrubber	93% if Units 3 & 4	2000	Install SCR	0.1	5/1/2009							

Company and Plant	State	Unit	Settlement Actions														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	
					(shared by Units 3 & 4)	are operating	(01/01/10)							from compliance with NSR settlement provisions must be retired.			
		Unit 4			Existing Scrubber (shared by Units 3 & 4)	93% if Units 3 & 4 are operating	6/22/2005	Install SCR	0.1	7/1/2007							
Gannon	Florida	Six units	Retire all six coal units and repower at least 550 MW of coal capacity to natural gas	12/31/2004													
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://www.epa.gov/compliance/resources/cases/civil/caa/wepco.html
Presque Isle	Wisconsin	Units 1 – 4	Retire or install SO_2 and NO_x controls	12/31/2012	Install and continuously operate FGD (or approved equiv. tech)	95% or 0.1	12/31/2012	Install SCR (or approved tech) and continually operate	0.1	12/31/2012				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.			
		Units 5 & 6						Install and operate low NO_x burners		12/31/2003							
		Units 7 & 8						Operate existing low NO_x burners		12/31/2005	Install Baghouse						
		Unit 9						Operate existing low NO_x burners		12/31/2006	Install Baghouse						
Pleasant Prairie	Wisconsin	1			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/2006	Install and continuously operate SCR (or approved tech)	0.1	12/31/2006							
		2			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/2007	Install and continuously operate SCR (or approved tech)	0.1	12/31/2003							

Company and Plant	State	Unit	Settlement Actions														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	
Oak Creek	Wisconsin	Units 5 & 6			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/2012	Install and continuously operate SCR (or approved tech)	0.1	12/31/2012							
		Unit 7			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/2012	Install and continuously operate SCR (or approved tech)	0.1	12/31/2012							
		Unit 8			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/2012	Install and continuously operate SCR (or approved tech)	0.1	12/31/2012							
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 there after. Beginning 1/1/2013 they will have a system wide emission rate no greater then 0.15 lb/MMBtu.																	
Mount Storm	West Virginia	Units 1 – 3			Construct or improve FGD	95% or 0.15	1/1/2005	Install and continuously operate SCR	0.11	1/1/2008				On or before March 31 of every year beginning in 2013 and continuing thereafter, VEPCO shall surrender 45,000 SO_2 allowances.			http://www.epa.gov/compliance/resources/cases/civil/caa/vepco.html
Chesterfield	Virginia	Unit 4						Install and continuously operate SCR	0.1	1/1/2013							
		Unit 5			Construct or improve FGD	95% or 0.13	10/12/2012	Install and continuously operate SCR	0.1	1/1/2012							
		Unit 6			Construct or improve FGD	95% or 0.13	1/1/2010	Install and continuously operate SCR	0.1	1/1/2011							
Chesapeake Energy	Virginia	Units 3 & 4						Install and continuously operate SCR	0.1	1/1/2013							