COST AND ENERGY IMPACTS – Technical Support Document

This chapter reports the cost, economic, and energy impact analysis performed for CAMR. EPA used the IPM, developed by ICF Consulting, to conduct its analysis. IPM is a dynamic linear programming model that can be used to examine air pollution control policies for Hg, SO_2, and NO_x throughout the contiguous United States for the entire power system. Documentation for IPM can be found at www.epa.gov/airmarkets/epa-ipm.

1 Modeling Background

The analysis presented here covers the electric power sector, a major source of Hg, SO_2, and NO_x emissions nationwide. CAMR requires that states control electric generation units fueled by coal through state Hg emissions reduction requirements. EPA has assumed that states implement those reductions through a cap-and-trade program. This analysis also assumes that electric generating units will also comply with CAIR requirements through a cap-and-trade program. For mercury, the analysis examines three control options, all implemented in multiple phases. See Table 1 for total annual Hg emissions caps for CAMR options examined. For SO_2 and NO_x, EPA modeled the requirements of the final CAIR. This modeling includes regionwide annual SO_2 and NO_x caps on the 23 States and the District and Columbia that are required to make annual reductions, and includes a regionwide ozone season NO_x cap on the 25 States and the District of Columbia required to make ozone season reductions. See Table 2 for total annual emissions caps under CAIR used in EPA modeling.

Table 1. CAMR Options Annual Emissions Caps (Tons)

	2010–2014	2015-2017	2018–Thereafter
Option 1 (38/15)	38	38	15
Option 2 (15/15)	38	15	15
Option 3 (24/15)	38	24	15

Table 2. CAIR Emissions Caps (Million Tons)

	2010–2014	2015–Thereafter
SO_2	3.6	2.5
NO_x (Annual)	1.5	1.3
NO_x (Summer)	0.6	0.5

The final CAMR requires annual Hg reductions in 50 States and the District of Columbia. The final CAMR will require a 38 ton cap in 2010 and a 15 ton cap in 2018. Using IPM, EPA modeled the cost and emissions impacts of three Hg control options to aid in its decision for the final CAMR. This chapter will provide the analysis conducted for all three options. IPM output files for the model runs used in CAMR analyses are available in the CAMR docket.

The modeling conducted for this analysis assumes that sources are complying with the final CAIR control strategy along with a CAMR control strategy. To provide incremental comparison, the CAIR modeling results are also presented. The CAIR IPM modeling includes regionwide annual SO_2 and NO_x caps on the 23 States and the District of Columbia for States required to make annual reductions, and includes a regionwide ozone season NO_x cap on the 25 States and the District of Columbia required to make ozone season reductions. EPA modeled the final CAIR NO_x strategy as an annual NO_x cap with a nested, separate ozone season NO_x cap.

CAMR was designed to achieve significant Hg emissions reductions from the power sector in a highly cost-effective manner. EPA analysis has found that the most efficient method to achieve the emissions reduction targets is through a cap-and-trade system that States have the option of adopting. States, in fact, can choose not to participate in the optional cap-and-trade program. However, EPA believes that a cap-and-trade system for the power sector is the best approach for reducing Hg emissions (see Chapter 18). As a result, EPA modeling has focused on the cap-and-trade approach for meeting the CAMR requirements. The modeling done with IPM assumes a nation-wide Hg cap and trade system on the power sector for the 48 contiguous states. However, EPA recognizes that states may use a different approach for reducing emissions, given that CAMR allows States to choose how they will meet their Hg emissions budget through reductions from utility units. States can elect not to participate in the federal trading program, and pursue reductions through other means including facility limits and trading limited to inside the state borders. As described below, this could impact the cost estimate of the program, but EPA conducted a sensitivity analysis of the most likely scenario involving States that do not participate in the federal trading program, and that analysis showed relatively little cost impact IPM has been used for evaluating the economic and emission impacts of environmental policies for over a decade. The model's base case incorporates Title IV of the Clean Air Act (the Acid Rain Program), the NO_x SIP Call, various New Source Review (NSR) settlements, and several state rules affecting emissions of SO_2 and NO_x that were finalized prior to April of 2004. The NSR settlements include agreements between EPA and Southern Indiana Gas and Electric Company (Vectren), Public Service Electric & Gas, Tampa Electric Company, We Energies (WEPCO), Virginia Electric Power Company (Dominion), and Santee Cooper. IPM also includes various current and future state programs in Connecticut, Illinois, Maine, Massachusetts, Minnesota, New Hampshire, North Carolina, New York, Oregon, Texas, and Wisconsin. IPM includes state rules that have been finalized and/or approved by a state's legislature or environmental agency. The base case is used to provide a reference point to compare environmental policies and assess their impacts and does not reflect a future scenario that EPA predicts will occur.

The economic modeling presented in this chapter has been developed for specific analyses of the power sector. Thus, the model has been designed to reflect the industry as accurately as possible. As a result, EPA has used discount rates in IPM that are appropriate for the various types of investments and other costs that the power sector incurs. The discount rates used in IPM may differ from discount rates used in other EPA analyses done for CAMR, particularly the discount rates used in the benefits analysis that are assumed to be social discount rates. EPA uses the best available information from utilities, financial institutions, debt rating agencies, and government statistics as the basis for the discount rates used for power sector modeling. These discount rates have undergone review by the power sector and the Energy Information Administration. EPA's discount rate approach has not been challenged in court.

EPA's modeling is based on its best judgment for various input assumptions that are uncertain, particularly assumptions for Hg control technology, future fuel prices and electricity demand growth. To some degree, EPA addresses the uncertainty surrounding these assumptions through its sensitivity analysis provided in the chapter. Other uncertainties, like states choosing not to participate in the trading program, would also impact the cost estimate.

More detail on IPM can be found in the model documentation, which provides additional information on the assumptions discussed here as well as all other assumptions and inputs to the model (www.epa.gov/airmarkets/epa-ipm).

2 Projected Hg Emissions

Because excess emission reductions are projected to be banked under the first phase of the Hg program, emissions in the second (or third phase under Option 2) will be initially higher than the cap that are required for CAMR. As shown in Figure 1, the results of EPA modeling of CAMR show state-by-state emissions in 2020 for some states do change significantly among CAMR options. However, for some states, the emissions projections among options follow the same profile as the national emission projections in 2020.

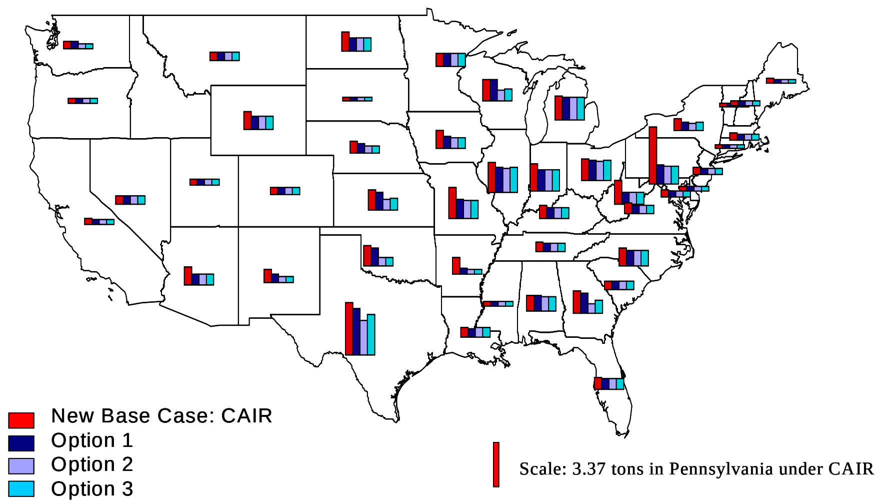

Figure 1 Projected Mercury Emissions in 2020 by State

Table 3 provides projected total Hg emissions levels and Table 4 provides projected speciated Hg emissions levels in 2020. EPA projections of Hg emissions are based on 1999 Hg ICR emission test data and other more recent testing conducted by EPA, DOE, and industry participants (for further discussion see *Control of Emissions from Coal-Fired Electric Utility Boilers: An Update*, EPA/Office of Research and Development, March 2005, in docket). That emissions testing has provided a better understanding of Hg emissions and their capture in pollution control devices. Mercury speciates into three basic forms, ionic, elemental, and particulate. In general, ionic Hg compounds are more readily adsorbed than elemental Hg. The presence of chlorine compounds (which tend to be higher for bituminous coals) results in increased ionic mercury.

Overall the 1999 Hg ICR data revealed higher levels of Hg capture for bituminous coal-fired plants as compared to low-rank coal-fired plants, large ranges of Hg capture in existing plants, higher levels of Hg capture in fabric filters (FF) compared to electrostatic precipitators (ESPs), and a significant capture of ionic Hg in wet SO_2 scrubbers. Additional Hg testing indicates that for bituminous coals SCR has the ability to convert elemental Hg to ionic Hg and thus allow easier capture in a wet scrubber. This understanding of Hg capture was incorporated into EPA modeling assumptions (see IPM documentation, Hg EMFs) and is the basis for projections of Hg co-benefits from installation of scrubbers and SCR under CAIR.

Table 3. Projected Emissions of Hg with the Old Base Case[a], New Base Case, and with CAMR Options (Tons)

	2010	2015	2020
Old Base Case	46.6	45.0	46.2
New Base Case: CAIR	38.0	34.4	34.0
Option 1 (38/15)	31.3	27.9	24.3
Option 2 (15/15)	30.9	25.7	20.1
Option 3 (24/15)	31.1	27.4	21.1

Note: The emissions projections are for coal-fired electric power units greater than 25 MW.
[a] Base case includes Title IV Acid Rain Program, NO_x SIP Call, and State rules finalized before March 2004.
Source: Integrated Planning Model run by EPA.

Table 4. Projected Speciated Emissions of Hg in 2020 with New Base Case (CAIR) and CAMR Options (Tons)

	Elemental Hg	Ionic Hg	Particulate Hg	Total
1999	26.2	20.6	1.7	48.6
New Base Case: CAIR	25.8	7.9	0.8	34.4
Option 1 (38/15)	17.6	6.6	0.8	25.0
Option 2 (15/15)	14.3	5.7	0.8	20.9
Option 3 (24/15)	15.1	5.9	0.8	21.8

Note: Numbers may not add due to rounding and include un affected units. The emissions data presented here are EPA modeling results and include some unaffected units. 1999 emissions from 1999 Hg ICR estimate.

3 Projected SO_2 and NO_x Emissions

The addition of Hg cap does not significantly affect SO_2 and NO_x emissions when compared to CAIR alone. National SO_2 emissions are somewhat lower in 2020 under the CAMR scenarios because sources are projected to install more scrubbers to achieve compliance for both CAIR and CAMR. Because of excess emission reductions that are projected to be banked under the Title IV Acid Rain Program and that sources will be allowed to use under the requirements of CAIR, emissions in 2010 and 2015 will be higher than the caps that are required for CAIR. Tables 5 and 6 provide projected emissions levels for SO_2 and NO_x.

Table 5. Projected Emissions of SO_2 with the Old Base Case[a], New Base Case (CAIR), and with CAMR Options (Million Tons)

	2010		2015		2020	
	Nationwide	CAIR Region	Nationwide	CAIR Region	Nationwide	CAIR Region
Old Base Case	9.7	8.8	8.9	8.0	8.6	7.7
New Base Case: CAIR	6.1	5.1	5.0	4.0	4.3	3.3
Option 1 (38/15)	6.1	5.1	4.9	4.0	4.2	3.3
Option 2 (15/15)	6.1	5.1	4.9	3.9	4.2	3.3
Option 3 (24/15)	6.1	5.1	4.9	4.0	4.2	3.3

Note: Emissions projections are for fossil-fired electric power sector.
[a] Base case includes Title IV Acid Rain Program, NO_x SIP Call, and State rules finalized before March 2004.
Source: Integrated Planning Model run by EPA.

Table 6. Projected Emissions of NO_x with the Old Base Case[a], New Base Case (CAIR), and with CAMR Options (Million Tons)

	2010		2015		2020	
	Nationwide	CAIR Region	Nationwide	CAIR Region	Nationwide	CAIR Region
Old Base Case	3.6	2.8	3.7	2.8	3.7	2.8
New Base Case: CAIR	2.5	1.5	2.2	1.3	2.2	1.3
Option 1 (38/15)	2.4	1.5	2.2	1.3	2.2	1.3
Option 2 (15/15)	2.4	1.5	2.2	1.3	2.2	1.3
Option 3 (24/15)	2.4	1.5	2.2	1.3	2.2	1.3

Note: Emissions projections are for fossil-fired electric power sector.
[a] Base case includes Title IV Acid Rain Program, NO_x SIP Call, and State rules finalized before March 2004.
Source: Integrated Planning Model run by EPA.

4 Projected Costs

Table 7 provides EPA's projections of annual and present value costs incremental to CAIR. The cost of electricity generation represents roughly one-third to one-half of total electricity costs, with transmission and distribution costs representing the remaining portion. A better impact measure of the cost to the consumer is the impact on electricity pricing, which is shown in a later table.

The presence of an earlier cap under CAMR Option 2 (an the reduction of years of banking excess emissions) results in higher projected costs than Option 1. CAMR Option 2 costs are projected to be the highest of the options and is reflected by the lowest projected Hg emissions in 2020. The intermediate cap of 24 tons under Option 3 also reduces the amount of banking of excess emissions and results in higher projected costs than Option 1. However, because the final cap goes into place in 2018, the projected costs are lower than Option 2 and is reflected by the projected Hg emission in 2020 being higher than Option 2.

The marginal costs for Hg, SO_2 and NO_x can be found in Table 8. EPA projects a reduction in the SO_2 allowance price and changes in the NO_x allowance price under CAMR when compared to CAIR alone. The changes in SO_2 and NO_x allowance prices are due to the different set of costs faced by sources under CAMR. In th case of SO_2, the ability to control for both Hg and SO_2 effectively through scrubbers results in marginal cost of SO_2 being reflected in th Hg allowance price such that SO_2 allowance price falls. In the case of NO_x, because SCR is an effective Hg control when combined with a scrubber, facilities choose to control different units than they would in th absence of a cap on Hg emissions. Sources will choose to control units where they can install a combination of scrubbers and SCR to achieve both mercury and NO_x reductions.

Table 7. Annualized National Private Compliance Cost and Present Value Cost ($1999)

Cost (billions)	2010	2015	2020	Present value (2007-2025)
Option 1 (38/15)	$0.16	$0.10	$0.75	$3.9
Option 2 (15/15)	$0.16	$0.36	$1.04	$6.0
Option 3 (24/15)	$0.16	$0.18	$1.04	$5.2

Note: Annual incremental costs of CAIR are $2.4 billion in 2010, $3.6 billion in 2015, and $4.4 billion in 2020, present value (2007-2025) is $41.1 billion.
Note: Numbers rounded to the nearest ten million for annualized cost.
Source: Integrated Planning Model run by EPA.

Table 8. Marginal Cost of Hg, SO_2, and NOx Reductions with CAMR Options ($1999)

		2010	2015	2020
New Base Case: CAIR	SO_2 ($/ton)	$800	$1,000	$1,300
	NOx ($/ton)	$1,300	$1,600	$1,600
Option 1 (38/15)	SO_2 ($/ton)	$700	$900	$1,200
	NOx ($/ton)	$1,200	$1,500	$1,300
	Hg ($/lb)	$23,200	$30,100	$39,000
Option 2 (15/15)	SO_2 ($/ton)	$700	$900	$1,100
	NOx ($/ton)	$1,200	$1,500	$1,200
	Hg ($/lb)	$29,000	$37,600	$48,700
Option 3 (24/15)	SO_2 ($/ton)	$700	$900	$1,100
	NOx ($/ton)	$1,200	$1,500	$1,300
	Hg ($/lb)	$26,400	$34,200	$44,400

Note: Numbers rounded to the nearest hundred for marginal cost.
Source: Integrated Planning Model run by EPA.

Actual costs may be lower than those presented since modeling assumes no improvements in the cost of mercury control technology. Given that this is the first time mercury emission will be regulated at the federal level[1] for the coal-fired power sector and given the current level of research and demonstration of mercury control technologies, control cost are expected to improve over time. For purposes of options comparisons, EPA has conservatively assumed no cost improvements in Hg control technologies. Later, in this chapter, EPA will present a sensitivity analysis in which we examine impact of mercury technology improvements by providing a lower cost mercury control option in future years.

5 Projected Control Technology Retrofits

Under the modeled Hg options, Hg reduction is projected to result from the installation of additional flue gas desulfurization (FGD or scrubbers) on existing coal-fired generation capacity for SO_2 control, additional selective catalytic reduction technology (SCR) on existing coal-fired generation capacity for NO_x control, and activated carbon injection (ACI) on existing coal-fired capacity for Hg-specific control (see Table 9). In addition, during the first phase of the Hg program, some Hg banking of emissions is projected to be attributed to coal switching and dispatch changes. Most of the NO_x reductions achieved in the first phase of the rule can be attributed to the large pool of existing SCR that are used during the ozone season in the NO_x SIP call region that, for relatively little additional cost, run the SCRs year-round. Due to earlier second phase cap (Option 2) and the addition of a third phase (Option 3), less banking is projected in 2010 to 2015 timeframe and results in more ACI in 2020 as emissions approach the 15 ton cap.

Table 9. Pollution Controls by Technology with the Old Base Case, New Base Case (CAIR), and with CAMR Options (GW)

	2010			2015			2020		
	FGD	SCR	ACI	FGD	SCR	ACI	FGD	SCR	ACI
Old Base Case	110	111	--	116	119	--	117	121	0.3
New Base Case: CAIR	146	125	--	177	151	--	198	153	0.5
Option 1 (38/15)	146	126	2	179	153	3	199	156	13
Option 2 (15/15)	146	127	3	179	153	12	198	156	38
Option 3 (24/15)	147	127	3	179	153	5	199	156	30

Note: Numbers may not add due to rounding. Base case retrofits include existing scrubbers and SCR as well as additional retrofits for the Title IV Acid Rain Program, the NO_x SIP call, NSR settlements, and various state rules.
Source: Integrated Planning Model run by EPA.

[1] Some states have enacted Hg reduction requirements for the coal-fired power sector. See IPM documentation for modeled State Hg regulations.

6 Projected Generation Mix

Table 10 shows the generation mix with CAMR. Coal-fired generation and natural gas-fired generation are projected to remain relatively unchanged because of the phased-in nature of CAMR, which allows industry the appropriate amount of time to install the necessary pollution controls.

Table 10. Generation Mix with the Old Base Case, with New Base Case (CAIR), and with CAMR Options (Thousand GWhs)

		2010	2015	2020	Change From New Base Case in 2020
Old Base Case	Coal	2,198	2,195	2,410	
	Oil/Natural Gas	777	1,072	1,221	
	Other	1,223	1,233	1,218	
New Base Case: CAIR	Coal	2,165	2,197	2,384	
	Oil/Natural Gas	807	1,069	1,247	
	Other	1,217	1,232	1,217	
Option 1 (38/15)	Coal	2,160	2,194	2,365	-0.8%
	Oil/Natural Gas	812	1,072	1,265	1.5%
	Other	1,216	1,233	1,217	0.0%
Option 2 (15/15)	Coal	2,158	2,191	2,365	-0.8%
	Oil/Natural Gas	813	1,075	1,266	1.5%
	Other	1,216	1,233	1,217	0.0%
Option 3 (24/15)	Coal	2,159	2,193	2,367	-0.7%
	Oil/Natural Gas	812	1,074	1,263	1.3%
	Other	1,216	1,232	1,217	0.0%

Note: Numbers may not add due to rounding.
Source: 2003 data are from EIA: Coal - 1,970; Oil/Natural Gas - 758; Other - 1,120. Projections are from the Integrated Planning Model run by EPA.

Under all three Hg control options modeled and relative to the new base case, no coal-fired generation is projected to be uneconomic to maintain under CAMR.

7 Projected Capacity Additions

In addition, EPA projects that future growth in electric demand will be met with a combination of new natural gas- and coal-fired capacity (see Table 11).

Table 11. Total Coal and Natural Oil/Gas-Fired Capacity by 2020 (GW)

	Current	Old Base Case	New Base Case: CAIR	Option 1 (38/15)	Option 2 (15/15)	Option 3 (24/15)
Pulverized Coal	305	318	315	314	314	314
IGCC	0.6	8	9	8	8	8
Oil/Gas	395	467	469	471	471	471

Source: Current data are from EPA's NEEDS 2004; projections are from the Integrated Planning Model run by EPA.

8 Projected Coal Production for the Electric Power Sector

Coal production for electricity generation is expected to increase relative to current levels, with or without CAIR (see Table 12). The reductions in emissions from the power sector will be met through the installation of pollution controls for Hg, SO_2 and NO_x removal. The pollution controls can achieve up to a 95 percent SO_2 removal rate, which allows industry to rely more heavily on local bituminous coal in the eastern and central parts of the country that has a higher sulfur content and is less expensive to transport than western subbituminous coal.

Table 12. Coal Production for the Electric Power Sector with the Old Base Case, New Base Case (CAIR) , and with CAMR Options (Million Tons)

			Old Base Case			New Base Case: CAIR		
Supply Area	**2000**	**2003**	**2010**	**2015**	**2020**	**2010**	**2015**	**2020**
Appalachia	299	275	325	315	301	306	306	331
Interior	131	135	161	162	173	165	191	218
West	475	526	603	631	714	607	586	609
National	905	936	1,089	1,109	1,188	1,078	1,083	1,158

Supply Area	**Option 1 (38/15)**			**Option 2 (15/15)**			**Option 3 (38/15)**		
	2010	**2015**	**2020**	**2010**	**2015**	**2020**	**2010**	**2015**	**2020**
Appalachia	303	310	330	303	309	322	304	309	325
Interior	169	194	224	170	195	231	171	194	232
West	589	568	572	587	565	574	587	567	570
National	1,061	1,071	1,127	1,060	1,069	1,127	1,061	1,070	1,127

Source: 2000 and 2003 data are derived from EIA data. All projections are from the Integrated Planning Model run by EPA.

9 Projected Retail Electricity Prices

Retail electricity prices for the U.S. are projected to increase a small amount with CAMR (see Table 13). The cap-and-trade approach allows industry to meet the requirements of CAMR in the most cost-effective manner, thereby minimizing the costs passed on to consumers. Retail electricity prices by NERC region (see Figure 2) are provided in Table 14 and show small increases in retail prices for the NERC regions in the eastern part of the country. By 2020, national retail electricity prices are projected to be roughly 0.3 percent higher with CAMR when compared to CAIR.

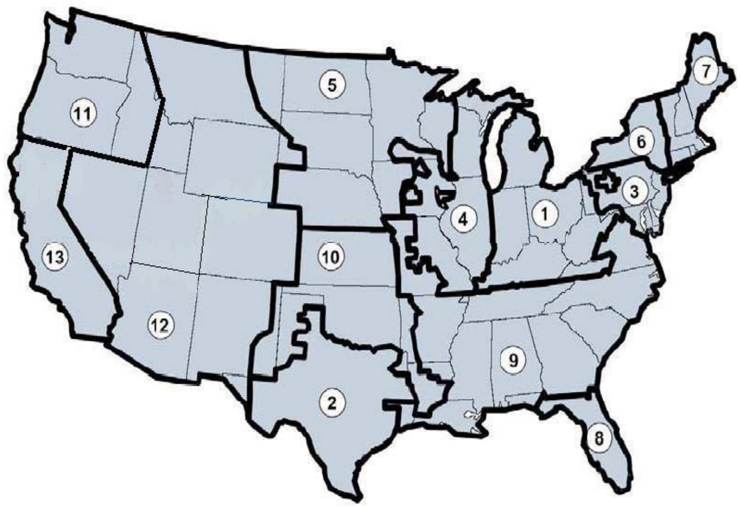

Figure 2. NERC Power Regions

Table 13. Projected National Retail Electricity Prices with the Old Base Case, New Base Case (CAIR), and CAMR Options (Mills/kWh) ($1999)

Year	Old Base Case	New Base Case: CAIR	Option 1 (38/15)	Option 2 (15/15)	Option 3 (24/15)
2010	58	61	61	61	61
2015	61	64	65	65	65
2020	61	64	65	65	65

Source: Retail Electricity Price Model run by EPA. 2000 national electric price is 66 mills/kWh from EIA's AEO 2003.

Table 14. Retail Electricity Prices by NERC Region with the Old Base Case, New Base Case (CAIR), and with CAMR Options (Mills/kWh) ($1999)

Option 1

			Base Case			CAIR			Option 1			Change from CAIR
Power Region	**Primary States Included**	**2000**	**2010**	**2015**	**2020**	**2010**	**2015**	**2020**	**2010**	**2015**	**2020**	**2020**
ECAR (1)	OH, MI, IN, KY, WV, PA	57.4	51.7	55.2	56.1	53.7	58.6	58.0	53.9	58.7	58.1	0.2%
ERCOT (2)	TX	65.1	57.9	64.4	62.6	59.4	64.5	63.3	59.1	64.9	63.4	0.1%
MAAC (3)	PA, NJ, MD, DC, DE	80.4	59.3	69.4	72.2	61.0	72.0	72.7	61.3	72.1	72.9	0.2%
MAIN (4)	IL, MO, WI	61.2	52.6	57.8	61.0	53.9	60.4	62.0	54.1	60.5	62.3	0.5%
MAPP (5)	MN, IA, SD, ND, NE	57.4	52.8	49.3	47.6	52.9	49.6	48.0	53.0	49.6	48.2	0.5%
NY (6)	NY	104.3	82.8	87.9	88.1	83.3	88.9	88.5	83.3	89.1	88.7	0.4%
NE (7)	VT, NH, ME, MA, CT, RI	89.9	77.4	83.9	82.8	77.4	84.7	83.1	77.5	84.8	83.1	0.0%
FRCC (8)	FL	67.9	71.2	71.3	69.5	71.7	72.3	70.5	71.8	72.3	70.7	0.3%
STV (9)	VA, NC, SC, GA, AL, MS, TN, AR, LA	59.3	56.2	55.1	55.3	57.0	56.2	56.6	57.1	56.2	56.8	0.3%
SPP (10)	KS, OK, MO	59.3	54.2	57.0	56.7	54.6	57.5	57.0	54.6	57.5	57.2	0.3%
PNW (11)	WA, OR, ID	45.9	49.6	47.4	46.9	49.8	47.5	46.9	49.8	47.5	47.1	0.5%
RM (12)	MT, WY, CO, UT, NM, AZ, NV, ID	64.1	63.9	65.2	64.7	64.1	65.6	65.4	64.2	65.6	65.1	-0.4%
CALI (13)	CA	94.7	97.1	98.9	99.3	97.3	99.1	99.5	97.3	99.1	99.7	0.3%
National	Contiguous Lower 48 States	66.0	60.3	63.1	63.4	61.3	64.5	64.3	61.3	64.5	64.5	0.2%

Option 2

			Base Case			CAIR			Option 2			Change from CAIR
Power Region	**Primary States Included**	**2000**	**2010**	**2015**	**2020**	**2010**	**2015**	**2020**	**2010**	**2015**	**2020**	**2020**
ECAR (1)	OH, MI, IN, KY, WV, PA	57.4	51.7	55.2	56.1	53.7	58.6	58.0	53.9	58.8	58.1	0.2%
ERCOT (2)	TX	65.1	57.9	64.4	62.6	59.4	64.5	63.3	59.1	64.9	63.4	0.1%
MAAC (3)	PA, NJ, MD, DC, DE	80.4	59.3	69.4	72.2	61.0	72.0	72.7	61.3	72.1	72.9	0.2%
MAIN (4)	IL, MO, WI	61.2	52.6	57.8	61.0	53.9	60.4	62.0	54.1	60.6	62.4	0.7%
MAPP (5)	MN, IA, SD, ND, NE	57.4	52.8	49.3	47.6	52.9	49.6	48.0	53.0	49.7	48.3	0.8%
NY (6)	NY	104.3	82.8	87.9	88.1	83.3	88.9	88.5	83.3	89.2	88.7	0.3%
NE (7)	VT, NH, ME, MA, CT, RI	89.9	77.4	83.9	82.8	77.4	84.7	83.1	77.5	84.7	83.2	0.2%
FRCC (8)	FL	67.9	71.2	71.3	69.5	71.7	72.3	70.5	71.7	72.3	70.7	0.3%
STV (9)	VA, NC, SC, GA, AL, MS, TN, AR, LA	59.3	56.2	55.1	55.3	57.0	56.2	56.6	57.1	56.4	56.8	0.4%
SPP (10)	KS, OK, MO	59.3	54.2	57.0	56.7	54.6	57.5	57.0	54.6	57.6	57.6	1.0%
PNW (11)	WA, OR, ID	45.9	49.6	47.4	46.9	49.8	47.5	46.9	49.8	47.4	47.2	0.6%
RM (12)	MT, WY, CO, UT, NM, AZ, NV, ID	64.1	63.9	65.2	64.7	64.1	65.6	65.4	64.2	65.6	65.0	-0.6%
CALI (13)	CA	94.7	97.1	98.9	99.3	97.3	99.1	99.5	97.3	99.1	99.7	0.3%
National	Contiguous Lower 48 States	66.0	60.3	63.1	63.4	61.3	64.5	64.3	61.3	64.6	64.5	0.3%

Option 3

			Base Case			CAIR			Option 3			Change from CAIR
Power Region	**Primary States Included**	**2000**	**2010**	**2015**	**2020**	**2010**	**2015**	**2020**	**2010**	**2015**	**2020**	**2020**
ECAR (1)	OH, MI, IN, KY, WV, PA	57.4	51.7	55.2	56.1	53.7	58.6	58.0	53.9	58.8	58.1	0.2%
ERCOT (2)	TX	65.1	57.9	64.4	62.6	59.4	64.5	63.3	59.1	64.9	63.4	0.1%
MAAC (3)	PA, NJ, MD, DC, DE	80.4	59.3	69.4	72.2	61.0	72.0	72.7	61.3	72.1	72.9	0.2%
MAIN (4)	IL, MO, WI	61.2	52.6	57.8	61.0	53.9	60.4	62.0	54.0	60.6	62.5	0.7%
MAPP (5)	MN, IA, SD, ND, NE	57.4	52.8	49.3	47.6	52.9	49.6	48.0	53.0	49.7	48.3	0.7%
NY (6)	NY	104.3	82.8	87.9	88.1	83.3	88.9	88.5	83.3	89.2	88.7	0.3%
NE (7)	VT, NH, ME, MA, CT, RI	89.9	77.4	83.9	82.8	77.4	84.7	83.1	77.5	84.8	83.1	0.0%
FRCC (8)	FL	67.9	71.2	71.3	69.5	71.7	72.3	70.5	71.8	72.3	70.7	0.3%
STV (9)	VA, NC, SC, GA, AL, MS, TN, AR, LA	59.3	56.2	55.1	55.3	57.0	56.2	56.6	57.1	56.3	56.8	0.4%
SPP (10)	KS, OK, MO	59.3	54.2	57.0	56.7	54.6	57.5	57.0	54.6	57.5	57.5	0.9%
PNW (11)	WA, OR, ID	45.9	49.6	47.4	46.9	49.8	47.5	46.9	49.8	47.4	47.2	0.6%
RM (12)	MT, WY, CO, UT, NM, AZ, NV, ID	64.1	63.9	65.2	64.7	64.1	65.6	65.4	64.2	65.6	65.1	-0.5%
CALI (13)	CA	94.7	97.1	98.9	99.3	97.3	99.1	99.5	97.3	99.1	99.8	0.3%
National	Contiguous Lower 48 States	66.0	60.3	63.1	63.4	61.3	64.5	64.3	61.3	64.6	64.5	0.3%

Source: Retail Electricity Price Model run by EPA. 2000 prices from EIA's AEO 2003.

10 Projected Fuel Price Impacts

The impacts of CAMR on coal prices and natural gas prices before shipment are shown in Table 15 .

Table 15. Henry Hub Natural Gas Prices and Average Delivered Coal Prices with the Old Base Case, New Base Case (CAIR), and with CAMR Options (1999$/mmBtu)

	2010		2015		2020	
	Delivered Coal	**Henry Hub Gas**	**Delivered Coal**	**Henry Hub Gas**	**Delivered Coal**	**Henry Hub Gas**
Old Base Case	1.05	3.20	1.01	3.25	0.96	3.16
New Base Case: CAIR	1.05	3.25	0.98	3.30	0.93	3.20
Option 1 (38/15)	1.05	3.25	0.98	3.30	0.93	3.25
Option 2 (15/15)	1.05	3.25	0.98	3.30	0.93	3.25
Option 3 (24/15)	1.05	3.25	0.98	3.30	0.94	3.25

Source: Integrated Planning Model run by EPA. 2000 natural gas data are from Platts GASdata is $4.15/mmBtu. 2000 coal price from EIA is $ 1.25/mmBtu.
Note: Coal price changes largely result from changes in the mix of coal types used. Delivered coal prices vary widely, but large changes in the cost of each type of coal are not projected.

11 Social Cost Calculations

The annualization factor used for pure social cost calculations (for annualized costs) normally includes the life of capital and the social discount rate. For purposes of benefit-cost analysis of this rule, EPA has calculated the annualized social costs using the discount rates from the benefits analysis for CAMR (3% and 7% and a 30 year life of capital. The costs of added insurance was included in the calculations, but local taxes were not included because they are considered to be transfer payments, and not a social cost). Using these discount rates, the social costs of CAMR incremental to CAIR are $151 million in 2010 and $848 million in 2020 using a discount rate of 3%, and are $157 million in 2010 and $896 million in 2020 using a discount rate of 7%.

Recent research suggests that the total social costs of a new regulation may be affected by interactions between the new regulation and pre-existing distortions in the economy, such as taxes. In particular, if cost increases due to a regulation are reflected in a general increase in the price level, the real wage received by workers may be reduced, leading to a small fall in the total amount of labor supplied. This “tax interaction effect” may result in an increase in deadweight loss in the labor market and an increase in total social costs. The limited empirical data available to support quantification of any such effect leads to this qualitative identification of the costs.

12 Limitations of Analysis

EPA’s modeling is based on its best judgment for various input assumptions that are uncertain, particularly assumptions for Hg control technologies and future fuel prices and electricity demand growth. To some degree, EPA addresses the uncertainty surrounding these three assumptions through its sensitivity analysis. Sensitivity analysis on future fuel prices and electricity demand growth are provided in section 15. A discussion on Hg technology cost uncertainty and sensitivity analysis are provided below in section 14. As a general matter, the Agency selects the best available information from available engineering studies of air pollution controls and has set up what it believes is the most reasonable modeling framework for analyzing the cost, emission changes, and other impacts of regulatory controls.

The annualized cost estimates of the private compliance costs that are provided in this analysis are meant to show the increase in production (engineering) costs of CAMR to the power sector. In simple terms, the private compliance costs that are presented are the annual increase in revenues required for the industry to be as well off after CAMR is implemented as before. To estimate these annualized costs, EPA uses a conventional and widely-accepted approach that is commonplace in economic analysis of power sector costs for estimating engineering costs in annual terms. For estimating annualized costs, EPA has applied a capital recovery factor (CRF) multiplier to capital investments and added that to the annual incremental operating expenses. The CRF is derived from estimates of the cost of capital (private discount rate), the amount of insurance coverage required, local property taxes, and the life of capital. The private compliance costs presented earlier are EPA's best estimate of the direct private compliance costs of CAMR.

The annualized cost of CAMR, as quantified here, is EPA's best assessment of the cost of implementing CAMR, assuming that States adopt the model cap and trade program. Under CAMR, States are required to meet Hg emission budget based on reductions from coal-fired utility units. States have the discretion to participate in the federal cap-and-trade program or to meet their budget through other options (including facility limits and trading restricted inside state boarder). These costs are generated from rigorous economic modeling of changes in the power sector due to CAMR. This type of analysis using IPM has undergone peer review and federal courts have upheld regulations covering the power sector that have relied on IPM’s cost analysis.

The direct private compliance cost includes, but is not limited to, capital investments in pollution controls, operating expenses of the pollution controls, investments in new generating sources, and additional fuel expenditures. EPA believes that the cost assumptions used for CAMR reflect, as closely as possible, the best information available to the Agency today. The cost associated with monitoring emissions, reporting, and record keeping for affected sources is not included in these annualized cost estimates, but EPA has done a separate analysis and estimated the cost to be about $76 million (see final CAMR preamble Section VI.B. Paperwork Reduction Act).

Furthermore, there are some unquantified costs that EPA wants to identify as limits to its analysis. These costs include the costs of federal and State administration of the program, which we believe are modest given our experience with the Acid Rain Program and the NOx Budget Trading Program and likely to be less than the alternative of States developing approvable State

Plans, securing EPA approval of those State Plans, and federal/state enforcement. There also may be unquantified costs of transitioning to CAMR, such as the costs associated with the retirement of smaller or less efficient electricity generating units, and employment shifts as workers are retrained at the same company or re-employed elsewhere in the economy. There are certain relatively small permitting costs associated with Title IV that new program entrants face (we believe there are far less than 1,000 new entrants who may require one day of additional work for trading permits). In a separate analysis for the CAIR RIA, EPA estimated the indirect cost and impacts of higher electricity prices on the entire economy for the CAIR scenario (see Regulatory Impact Analysis for the Final Clean Air Interstate Rule, Appendix E (March 2005)). Given the small difference in electricity prices between CAMR and CAIR, analysis for CAMR would project similar results.

Cost estimates for CAMR are based on results from ICF's Integrated Planning Model. The model minimizes the costs of producing electricity (including abatement costs) while meeting load demand and other constraints (full documentation for IPM can be found at www.epa.gov/airmarkets/epa-ipm). The structure of the model assumes that the electric utility industry will be able to meet the environmental emission caps at least cost. Montgomery (1972) has shown that this least cost solution corresponds to the equilibrium of an emission permit system.[2] See also Atkinson and Tietenburg (1982), Krupnick et al. (1980), and McGartland and Oates (1985).[3] [4] [5] However, to the extent that transaction and/or search costs, combined with institutional barriers, restrict the ability of utilities to exhaust all the gains from emissions trading, costs are underestimated by the model. Utilities in the IPM model also have "perfect foresight." To the extent that utilities misjudge future conditions affecting the economics of pollution control, costs may be understated as well.

This modeling analysis does not take into account the potential for advancements in the capabilities of pollution control technologies for SO_2 and NO_x removal as well as reductions in their costs over time. Market-based cap-and-trade regulation serves to promote innovation and the development of new and cheaper technologies. As an example, recent cost estimates of the Acid Rain SO_2 trading program by Resources for the Future (RFF) and MIT's Center for Energy and Environmental Policy Research (CEEPR) have been as much as 83% lower than originally projected by the EPA[6]. It is important to note that the original analysis for the Acid Rain

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[2] Montgomery, W. David 1972. "Markets in Licenses and Efficient Pollution Control Programs." *Journal of Economic Theory* 5(3): 395-418.

[3] S. Atkinson and T. Tietenberg 1982. "The empirical properties of two classes of design for transferable discharge permit markets," *Journal of Environmental Economics and Management* 9:101-121

[4] Krupnick, A., W. Oates and E. Van De Verg. 1980. "On Marketable Air Pollution Permits: The Case for a System of Pollution Offsets." *Journal of Environmental Economics and Management* 10: 233-47.

[5] McGartland, A and W. Oates. 1985. "Marketable Permits for the Prevention of Environmental Deterioration," *Journal of Environmental Economics and Management* 12: 207-228.

[6] See (1) Carlson, Curtis.; Burtraw, Dallas R.; Cropper, Maureen and Palmer, Karen L. 2000. Sulfur Dioxide Control by Electric Utilities: What Are the Gain from Trade? *Journal of Political Economy* 108 (#6): 1292-1326, and (2) Ellerman, Denny. January, 2003. Ex Post Evaluation of Tradable Permits: The U.S. SO2 Cap-and-Trade Program.

Program done by EPA also relied on an optimization model like IPM. Ex ante, EPA costs estimates of roughly \$2.7 to \$6.2 billion[7] in 1989 were an overestimate of the costs of the program in part because of the limitation of economic modeling to predict technological improvement of pollution controls and other compliance options such as fuel switching. Ex post estimates of the annual cost of the Acid Rain SO_2 trading program range from \$1.0 to \$1.4 billion. Harrington et al. have compared estimates of actual costs of many large EPA regulatory programs to predictions of those costs made while programs were under development and found a tendency for predicted costs to overstate actual implementation costs for market-based programs.[8] EPA's mobile source programs use adjusted engineering cost estimates to account for this fact, which EPA has not done in this case.[9]

As configured in this application, the IPM model does not take into account demand response (i.e., consumer reaction to electricity prices). The increased retail electricity prices shown in Table 14 would prompt end users to curtail (to some extent) their use of electricity and encourage them to use substitutes.[10] The response would lessen the demand for electricity, lowering electricity prices and reducing generation and emissions. Because of demand response, certain unquantified negative costs (i.e., savings) result from the reduced resource costs of producing less electricity because of lower demand. To some degree, these saved resource costs will offset the additional costs of pollution controls and fuel switching that we would anticipate with CAMR. Although the reduction in electricity use is likely to be small, the cost savings from such a large industry (\$250 billion in revenues in 2003) is likely to be substantial. EIA analysis examining multi-pollutant legislation under consideration in 2003 indicates that the annualized costs of CAMR may be overstated substantially by not considering demand response.

It is also important to note that the capital cost assumptions for scrubbers used in EPA modeling applications are highly conservative. These are a substantial part of the compliance costs. Data available from recent published sources show the reported FGD costs from recent installations to be below the levels projected by the IPM. In addition, EPA conducted a survey of recent FGD installations and compared the costs of these installations to the costs used in IPM. This survey included small, mid-size, and large units. Examples of the comparison of these referenced published data with the FGD capital cost estimates obtained from IPM are provided in the Final CAMR docket. There is also evidence that scrubber costs will decrease in the future because of the learning-by-doing phenomenon, as more scrubbers are installed[11].

Massachusetts Institute of Technology Center for Energy and Environmental Policy Research.

[7] 2010 Phase II cost estimate in \$1995.

[8] Harrington, W. R.D. Morgenstern, and P. Nelson, 2000. "On the Accuracy of Regulatory Cost Estimates," Journal of Policy Analysis and Management 19(2): 297-322.

[9] See recent regulatory impact analysis for the Tier 2 Regulations for passenger vehicles (1999) and Heavy-Duty Diesel Vehicle Rules (2000).

[10] The degree of substitution/curtailment depends on the price elasticity of electricity.

[11] Manson, Nelson, and Neumann, 2002. "Assessing the Impact of Progress and Learning Curves on Clean Air Act Compliance Costs," Industrial Economics Incorporated.

Another area of uncertainty is the performance of mercury control removal systems, like the one assumed in the modeling, activated carbon injection with added pulse-jet fabric filters. ACI systems have shown great promise in demonstrated tests. However, there is uncertainty about the availability and effectiveness of ACI across all coal types in the 2010 timeframe, since these systems have not been fully deployed on coal-fired generating plants. EPA's assumption of 90% removal for ACI is based on EPA's Office of Research and Development (ORD) assessment (for further discussion see *Control of Emissions from Coal-Fired Electric Utility Boilers: An Update*, EPA/Office of Research and Development, March 2005, in CAMR docket). Although modeled in IPM to be available immediately for all coal-fired generation as a simplification of modeling, ORD assessment concluded that ACI could not be fully deployed on all plants by 2010 timeframe. EPA's modeling projects only a small amount of ACI use in the 2010 timeframe which is consistent with ORD's conclusion about the availability of ACI.

An additional limitation of Hg control assumptions is that we are assuming no development in control technologies even though we recognize that this is a fast moving area with new developments nearly monthly. Actual costs may be lower than those presented since modeling assumes no improvements in the cost of mercury control technology. Given that this is the first time mercury is regulated for the coal-fired power sector and the current level of research and demonstration of mercury control technologies, control cost are expected to improve over time. For purposes of modeling, EPA has conservatively based its cost assumptions for mercury control on today's knowledge and not included cost improvement assumption in the modeling. Later, in this chapter (section 14), EPA presents a sensitivity analysis in which we examine impact of mercury technology improvements by providing a lower cost mercury control option in future years. It is important to note that CAMR's cap-and-trade approach will encourage technological innovation in Hg emissions control and allow sources to exploit currently unforeseen emissions control technologies.

Further, while there are many choices of technology for mercury control in existence or under development, several are not offered to model plants in IPM. Plants in IPM cannot retrofit with a fabric filter or make improvements to existing controls to capture mercury, such as improving the cloth to air ratio of the fabric filter, up-grading their ESP or injecting carbon. In addition, research and development continues on other Hg control technologies, including the use of pre-combustion controls (e.g. K-fuels), or multi-pollutant controls (i.e., one control removing SO_2, NO_x, and Hg). Given a cap-and-trade approach, we would expect further development and innovation of technology.

EPA’s latest update of IPM incorporates State rules or regulations adopted before March 2004 and various NSR settlements. Documentation for IPM can be found at www.epa.gov/airmarkets/epa-ipm. Any State or settlement action since that time has not been accounted for in our analysis in this chapter.

On balance, after consideration of various unquantified costs (and savings that are possible), EPA believes that the annual private compliance costs that we have estimated are more likely to overstate the future annual compliance costs that industry will incur, rather than understate those costs.

13 Significant Energy Impact

According to *E.O. 13211: Actions that Significantly Affect Energy Supply, Distribution, or Use,* this rule is not significant, measured incrementally to CAIR, because it does not have a greater than a 1 percent impact on the cost of electricity production and it does not result in the retirement of greater than 500 MW of coal-fired generation.

Several aspects of CAMR are designed to minimize the impact on energy production. First, EPA recommends a trading program rather than the use of command-and-control regulations. Second, compliance deadlines are set cognizant of the impact that those deadlines have on electricity production. Both of these aspects of CAMR reduce the impact of the proposal on the electricity sector.

14 Sensitivity Analysis on Assumptions for Hg Control Costs

This section presents results of cost sensitivity analysis using the IPM. As discussed earlier in this chapter, actual costs may be lower than those presented since modeling assumes no improvements in the cost of mercury control technology. Given that this is the first time mercury is federally regulated for the coal-fired power sector and given the current level of research and demonstration of mercury control technologies, control cost are expected to improve over time. The sensitivity analysis presented examines the impacts of possible improvements in Hg control costs over time. EPA selected Option 1 as the policy option for the final CAMR. For that reason, EPA proceeded with sensitivity analyses for that option.

The sensitivity analysis presented includes examination of the impact of mercury technology improvements by providing a lower cost mercury control option in future years. Specifically, the sensitivity analysis examines the impact of providing a second ACI option in 2013 with brominated sorbents and lower capital costs. The assumptions of costs and performance for the sensitivity analysis is based on recent testing sponsored by EPA, DOE, and industry and more information on these advanced sorbents can be found in white paper by EPA's Office of Research and Development, available in the docket. For purposes of modeling, EPA has assumed the availability of two ACI options: (1) ACI using conventional sorbents and achieving 90% removal with the addition of a fabric filter; and (2) ACI using advanced sorbents and achieving 80 to 90% removal without the addition of a fabric filter (see memorandum to the docket entitled "Assumptions used in sensitivity analysis for the Clean Air Mercury Rule"). The first ACI option is available at the start of the model and the second ACI is available in 2013. For comparison of impacts, the sorbent sensitivity was modeled based on the reduction levels for CAMR Option 1 (Hg trading scenario plus CAIR of 38 tons in 2010, 15 tons in 2018).

Tables 16 and 17 provide Hg, SO_2, and NOx emission projections for the sorbent sensitivity option. Because the banking of excess emission under the first phase of the Hg program, emissions are projected to be higher than the cap that is required for CAMR in 2020. However, with lower future Hg technology costs, less banking and higher emissions are projected in 2010 and 2015 under the sorbent sensitivity option.

Table 19 provides annual and present value costs incremental to CAIR and Table 20 provides marginal costs. Under the sorbent sensitivity, the second ACI option has higher O&M

costs, but lower capital costs resulting in overall lower cost projections. Compared with CAMR option 1, annual costs and present value cost are projected to be lower for the sorbent sensitivity option and Hg marginal cost are projected to be about 50 percent lower.

The lower costs for ACI technology also results in higher projections of ACI retrofits in 2020 for the sorbent sensitivity option (see Table 21). When compared to Option 1, Coal generation and production are projected to increase under the sorbent sensitivity option (see Tables 22, 23, and 24). Retail electricity prices are not projected to changes significantly when comparing the sorbent sensitivity option to Option 1 (see Table 25).

Table 16. Projected Emissions of Hg with New Base Case (CAIR) and CAMR, without and with Selected Technological Advances (Tons)

	2010	2015	2020
New Base Case: CAIR	38.0	34.4	34.0
Option 1 – Current Technology	31.3	27.9	24.3
Option 1 – Sorbent Sensitivity	32.6	29.3	23.1

Note: The emissions data presented here are EPA modeling results.

Table 17. Projected Emissions of SO_2 with New Base Case (CAIR) and CAMR, without and with Selected Technological Advances (Million Tons)

	2010		2015		2020	
	Nationwide	CAIR Region	Nationwide	CAIR Region	Nationwide	CAIR Region
New Base Case: CAIR	6.1	5.1	5.0	4.0	4.3	3.3
Option 1 – Current Technology	6.1	5.1	4.9	4.0	4.2	3.3
Option 1 – Sorbent Sensitivity	6.1	5.1	4.9	4.0	4.3	3.3

Source: Integrated Planning Model run by EPA.

Table 18. Projected Emissions of NO_x with the New Base Case (CAIR) and CAMR without and with Selected Technological Advances (Million Tons)

	2010		2015		2020	
	Nationwide	CAIR Region	Nationwide	CAIR Region	Nationwide	CAIR Region
New Base Case: CAIR	2.5	1.5	2.2	1.3	2.2	1.3
Option 1 – Current Technology	2.4	1.5	2.2	1.3	2.2	1.3
Option 1 – Sorbent Sensitivity	2.4	1.5	2.2	1.3	2.2	1.3

Source: Integrated Planning Model run by EPA.

Table 19. Annualized Private Compliance Cost and Present Value Cost Incremental to the New Base Case (CAIR) ($1999)

Cost (billions)	2010	2015	2020	Present value (2007-2025)
Option 1 – Current Technology	$0.16	$0.10	$0.75	$3.9
Option 1 – Sorbent Sensitivity	$0.10	$0.04	$0.56	$2.2

Note: Annual incremental costs of CAIR are $2.4 billion in 2010, $3.6 billion in 2015, and $4.4 billion in 2020, present value (2007-2025) is $41.1 billion.
Note: Numbers rounded to the nearest hundred million for annualized cost.
Source: Integrated Planning Model run by EPA.

Table 20. Marginal Cost of Hg, SO_2, and NO_x Reductions with CAMR without and with Selected Technological Advances ($1999)

		2010	2015	2020
New Base Case: CAIR	SO_2 ($/ton)	$800	$1,000	$1,300
	NOx ($/ton)	$1,300	$1,600	$1,600
Option 1 – Current Technology	SO_2 ($/ton)	$700	$900	$1,200
	NOx ($/ton)	$1,200	$1,500	$1,300
	Hg ($/lb)	$23,200	$30,100	$39,000
Option 1 – Sorbent Sensitivity	SO_2 ($/ton)	$800	$1,000	$1,300
	NOx ($/ton)	$1,200	$1,500	$1,400
	Hg ($/lb)	$11,800	$15,300	$19,900

Note: Numbers rounded to the nearest hundred for marginal cost.
Source: Integrated Planning Model run by EPA.

Table 21. Pollution Controls by Technology with the New Base Case (CAIR), and CAMR without and with Selected Technological Advances (GW)

	2010			2015			2020		
	FGD	SCR	ACI	FGD	SCR	ACI	FGD	SCR	ACI
New Base Case: CAIR	146	125	--	177	151	--	198	153	0.5
Option 1 – Current Technology	146	126	2	179	153	3	199	156	13
Option 1 – Sorbent Sensitivity	146	126	1	179	153	3	197	155	25

Note: Retrofits include existing scrubbers and SCR as well as additional retrofits for the Title IV Acid Rain Program, the NO_x SIP call, NSR settlements, and various state rules.

Source: Integrated Planning Model run by EPA.

Table 22. Generation Mix with the Old Base Case, the New Base Case (CAIR), and with CAMR without and with Selected Technological Advances (Thousand GWhs)

		2010	2015	2020	Change From New Base Case in 2020
Old Base Case	Coal	2,198	2,195	2,410	
	Oil/Natural Gas	777	1,072	1,221	
	Other	1,223	1,233	1,218	
New Base Case: CAIR	Coal	2,165	2,197	2,384	
	Oil/Natural Gas	807	1,069	1,247	
	Other	1,217	1,232	1,217	
Option 1 – Current Technology	Coal	2,160	2,194	2,365	-0.8%
	Oil/Natural Gas	812	1,072	1,265	1.5%
	Other	1,216	1,233	1,217	0.0%
Option 1– Sorbent Sensitivity	Coal	2,161	2,196	2,372	-0.5%
	Oil/Natural Gas	811	1,070	1,258	0.9%
	Other	1,217	1,233	1,217	0.0%

Note: Numbers may not add due to rounding.

Source: 2003 data are from EIA: Coal - 1,970; Oil/Natural Gas - 758; Other - 1,120. Projections are from the Integrated Planning Model run by EPA.

Table 23. Total Coal and Natural Oil/Gas-Fired Capacity by 2020 (GW)

	Current	Old Base Case	New Base Case: CAIR	Option 1 – Current Technology	Option 1 – Sorbent Sensitivity
Pulverized Coal	305	318	315	314	314
IGCC	0.6	8	9	8	9
Oil/Gas	395	467	469	471	470

Source: Current data are from EPA's NEEDS 2004; projections are from the Integrated Planning Model run by EPA.

Table 24. Coal Production for the Electric Power Sector with the Old Base Case, New Base Case (CAIR) , and with CAMR without and with Selected Technological Advances (Million Tons)

			Old Base Case			New Base Case: CAIR		
Supply Area	**2000**	**2003**	**2010**	**2015**	**2020**	**2010**	**2015**	**2020**
Appalachia	299	275	325	315	301	306	306	331
Interior	131	135	161	162	173	165	191	218
West	475	526	603	631	714	607	586	609
National	905	936	1,089	1,109	1,188	1,078	1,083	1,158

Supply Area	Option 1 – Current Technology			Option 1 – Sorbent Sensitivity		
	2010	**2015**	**2020**	**2010**	**2015**	**2020**
Appalachia	303	310	330	305	312	333
Interior	169	194	224	168	191	220
West	589	568	572	592	578	579
National	1,061	1,071	1,127	1,065	1,081	1,132

Source: 2000 and 2003 data are derived from EIA data. All projections are from the Integrated Planning Model run by EPA.

Table 25. Retail Electricity Prices by NERC Region with the Old Base Case, New Base Case (CAIR), and with CAMR without and with Selected Technological Advances (Mills/kWh) ($1999)

Option 1

			Base Case			CAIR			Option 1			Change from CAIR
Power Region	**Primary States Included**	**2000**	**2010**	**2015**	**2020**	**2010**	**2015**	**2020**	**2010**	**2015**	**2020**	**2020**
ECAR	OH, MI, IN, KY, WV, PA	57.4	51.7	55.2	56.1	53.7	58.6	58.0	53.9	58.7	58.1	0.2%
ERCOT	TX	65.1	57.9	64.4	62.6	59.4	64.5	63.3	59.1	64.9	63.4	0.1%
MAAC	PA, NJ, MD, DC, DE	80.4	59.3	69.4	72.2	61.0	72.0	72.7	61.3	72.1	72.9	0.2%
MAIN	IL, MO, WI	61.2	52.6	57.8	61.0	53.9	60.4	62.0	54.1	60.5	62.3	0.5%
MAPP	MN, IA, SD, ND, NE	57.4	52.8	49.3	47.6	52.9	49.6	48.0	53.0	49.6	48.2	0.5%
NY	NY	104.3	82.8	87.9	88.1	83.3	88.9	88.5	83.3	89.1	88.7	0.4%
NE	VT, NH, ME, MA, CT, RI	89.9	77.4	83.9	82.8	77.4	84.7	83.1	77.5	84.8	83.1	0.0%
FRCC	FL	67.9	71.2	71.3	69.5	71.7	72.3	70.5	71.8	72.3	70.7	0.3%
STV	VA, NC, SC, GA, AL, MS, TN, AR, LA	59.3	56.2	55.1	55.3	57.0	56.2	56.6	57.1	56.2	56.8	0.3%
SPP	KS, OK, MO	59.3	54.2	57.0	56.7	54.6	57.5	57.0	54.6	57.5	57.2	0.3%
PNW	WA, OR, ID	45.9	49.6	47.4	46.9	49.8	47.5	46.9	49.8	47.5	47.1	0.5%
RM	MT, WY, CO, UT, NM, AZ, NV, ID	64.1	63.9	65.2	64.7	64.1	65.6	65.4	64.2	65.6	65.1	-0.4%
CALI	CA	94.7	97.1	98.9	99.3	97.3	99.1	99.5	97.3	99.1	99.7	0.3%
National	Contiguous Lower 48 States	66.0	60.3	63.1	63.4	61.3	64.5	64.3	61.3	64.5	64.5	0.2%

Sorbent Sensitivity

			Base Case			CAIR			Sensitivity			Change from CAIR
Power Region	**Primary States Included**	**2000**	**2010**	**2015**	**2020**	**2010**	**2015**	**2020**	**2010**	**2015**	**2020**	**2020**
ECAR (1)	OH, MI, IN, KY, WV, PA	57.4	51.7	55.2	56.1	53.7	58.6	58.0	53.8	58.6	58.0	0.1%
ERCOT (2)	TX	65.1	57.9	64.4	62.6	59.4	64.5	63.3	59.2	64.9	63.4	0.2%
MAAC (3)	PA, NJ, MD, DC, DE	80.4	59.3	69.4	72.2	61.0	72.0	72.7	61.1	72.0	72.9	0.2%
MAIN (4)	IL, MO, WI	61.2	52.6	57.8	61.0	53.9	60.4	62.0	54.0	60.5	62.3	0.4%
MAPP (5)	MN, IA, SD, ND, NE	57.4	52.8	49.3	47.6	52.9	49.6	48.0	52.9	49.6	48.0	0.1%
NY (6)	NY	104.3	82.8	87.9	88.1	83.3	88.9	88.5	83.3	89.1	88.8	0.3%
NE (7)	VT, NH, ME, MA, CT, RI	89.9	77.4	83.9	82.8	77.4	84.7	83.1	77.5	85.0	83.0	-0.1%
FRCC (8)	FL	67.9	71.2	71.3	69.5	71.7	72.3	70.5	71.8	72.3	70.7	0.2%
STV (9)	VA, NC, SC, GA, AL, MS, TN, AR, LA	59.3	56.2	55.1	55.3	57.0	56.2	56.6	57.1	56.2	56.7	0.3%
SPP (10)	KS, OK, MO	59.3	54.2	57.0	56.7	54.6	57.5	57.0	54.6	57.5	57.2	0.3%
PNW (11)	WA, OR, ID	45.9	49.6	47.4	46.9	49.8	47.5	46.9	49.8	47.5	47.2	0.5%
RM (12)	MT, WY, CO, UT, NM, AZ, NV, ID	64.1	63.9	65.2	64.7	64.1	65.6	65.4	64.1	65.6	65.3	-0.2%
CALI (13)	CA	94.7	97.1	98.9	99.3	97.3	99.1	99.5	97.2	99.1	99.7	0.22%
National	Contiguous Lower 48 States	66.0	60.3	63.1	63.4	61.3	64.5	64.3	61.3	64.5	64.4	0.2%

Source: Retail Electricity Price Model run by EPA. 2000 prices from EIA's AEO 2003.

15 Sensitivity Analysis on Assumptions for Natural Gas Prices and Electricity Growth

Sensitivity analyses were performed using projections from the 2004 Annual Energy Outlook produced by the Energy Information Administration (EIA). EPA used EIA estimates for the difference between natural gas prices and coal prices, which we have short-handed as "EIA natural gas prices," as well as EIA's projection of electricity growth. These particular assumptions involve considering the higher differential between minemouth coal and wellhead natural gas prices. For the years 2010, 2015, and 2020, there was a higher differential of $0.25 mmBtu, $0.42 mmBtu, and $0.38 mmBtu, respectively. The electricity growth was changed to match EIA's growth of 1.8 percent a year rather than EPA's growth of 1.6 percent.

Nationwide emissions of Hg, SO_2, and NOx using EIA assumptions are presented in Tables 26 and 27. Mercury emissions profiles with EIA assumptions are similar and lower than emissions with EPA assumptions. Lower Hg emissions for EIA assumptions can be attributed to the building of new and cleaner coal-fired capacity.

Total annual costs and present value costs of CAMR incremental to CAIR with EIA assumptions are in Table 28. The costs of CAMR with EIA assumptions for natural gas prices and electricity growth in 2010 and 2015 are only slightly different from costs of CAIR without those assumptions and can be attributed to the building of new and cleaner coal-fired capacity that leads to lower overall costs (see Tables 28 and 29). As demand continues to grow, coal-fired generation continues to increase and requires the use of additional scrubbers. Although more pollution controls are installed using EIA assumptions, dispatch changes lead to the use of more efficient generation. The power sector is less inclined to use gas as a compliance option in the region because of the higher operating cost. Once the power sector passes the point where there is no longer excess gas capacity in the marketplace (as currently exists), new coal-fired capacity is the logical choice to meet demand.

Coal-fired generation under CAMR increases using EIA assumptions for natural gas prices and electricity growth. Table 31 shows the generation mix with EIA assumptions. Coal production patterns change slightly and production for all three major coal-producing regions is higher, because coal-fired generation is a cheaper source of electricity than natural gas in most parts of the country with the higher EIA prices, even as more pollution controls are added to coal-fired generation and used to meet the additional electricity demand (see Table 32).

Electricity prices are not greatly altered with EIA assumptions for natural gas and electricity growth (see Table 33). Average electricity prices are projected to be lower than current levels (2000) using both EPA and EIA assumptions for natural gas and electricity growth.

Table 26. Projected Emissions of Hg for the New Base Case (CAIR) and CAMR with EPA and EIA Assumptions for Natural Gas Prices and Electric Growth (Tons)

		2010	2015	2020
Old Base Case	EPA Assumptions	46.6	45.0	46.2
	EIA Assumptions	47.5	47.0	47.8
New Base Case: CAIR	EPA Assumptions	38.0	34.4	34.0
	EIA Assumptions	38.3	35.2	35.4
Option 1	EPA Assumptions	31.3	27.9	24.3
	EIA Assumptions	31.5	28.5	23.5

Note: The emissions data presented here are EPA modeling results.

Table 27. Projected Nationwide Emissions of SO_2 and NO_x under the New Base Case (CAIR) and CAMR with EPA and EIA Assumptions for Natural Gas and Electric Growth

(Million Tons)

	SO_2			NOx		
	2010	2015	2020	2010	2015	2020
Old Base Case with EPA Assumptions	9.7	8.9	8.6	3.6	3.7	3.7
New Base Case (CAIR) with EPA Assumptions	6.1	5.0	4.3	2.5	2.2	2.2
Option 1 with EPA Assumptions	6.1	4.9	4.2	2.4	2.2	2.2
Old Base Case with EIA Assumptions	9.7	8.8	8.6	3.7	3.8	3.8
New Base Case (CAIR) with EIA Assumptions	6.1	5.0	4.0	2.4	2.1	2.2
Option 1 with EIA Assumptions	6.1	4.9	4.3	2.4	2.2	2.2

Source: Integrated Planning Model run by EPA.

Table 28. Annualized Cost and Present Value Cost Incremental to the New Base Case (CAIR) with EPA and EIA Assumptions for Natural Gas Prices and Electric Growth (Billion $1999)

	2010	2015	2020	Present value (2007-2025)
Option 1- EPA Assumptions	$0.16	$0.10	$0.75	$3.9
Option 1 - EIA Assumptions	$0.16	$0.21	$0.53	$3.1

Note: Annual incremental costs of CAIR with EPA assumptions are $2.4 billion in 2010, $3.6 billion in 2015, and $4.4 billion in 2020, present value (2007-2025) is $41.1 billion. Annual incremental costs of CAIR with EIA assumptions are $2.6 billion in 2010, $3.4 billion in 2015, and $4.1 billion in 2020, present value (2007-2025) is $42.9 billion.
Note: Numbers rounded to the nearest tenth million for annualized cost.
Source: Integrated Planning Model run by EPA.

Table 29. Marginal Cost of SO_2 and NO_x Reductions under the New Base Case (CAIR) and CAMR with EPA and EIA Assumptions for Natural Gas Prices and Electric Growth ($/ton, in $1999)

			2010	2015	2020
New Base Case: CAIR	SO_2	EPA Assumptions	$800	$1,000	$1,300
		EIA Assumptions	$800	$1,200	$1,500
	NOx	EPA Assumptions	$1,300	$1,600	$1,600
		EIA Assumptions	$1,400	$1,700	$1,700
Option 1	SO_2	EPA Assumptions	$700	$900	$1,200
		EIA Assumptions	$800	$1,000	$1,300
	NOx	EPA Assumptions	$1,200	$1,500	$1,200
		EIA Assumptions	$1,200	$1,600	$1,300
	Hg	EPA Assumptions	$23,200	$30,100	$39,000
		EIA Assumptions	$26,400	$34,200	$44,400

Source: Integrated Planning Model run by EPA.

Table 30. Pollution Controls under the New Base Case (CAIR) with EPA and EIA Assumptions for Natural Gas and Electricity Growth (GWs)

		EPA Assumptions			EIA Assumptions		
	Technology	2010	2015	2020	2010	2015	2020
New Base Case: CAIR	FGD	146	177	198	157	185	209
	SCR	125	151	153	134	161	162
Option 1	FGD	146	179	199	155	187	203
	SCR	126	153	156	137	160	162
	ACI	2	3	13	3	4	26

Note: Retrofits include existing scrubbers and SCR as well as additional retrofits for the Title IV Acid Rain Program, the NO_x SIP call, NSR settlements, and various state rules.

Source: Integrated Planning Model run by EPA.

Table 31. Generation Mix under the New Base Case (CAIR) and CAMR with EPA and EIA Assumptions for Natural Gas and Electric Growth (Thousand GWhs)

		EPA Assumptions			EIA Assumptions		
	Fuel	**2010**	**2015**	**2020**	**2010**	**2015**	**2020**
Old Base Case	Coal	2,198	2,242	2,410	2,243	2,638	3,048
	Oil/Natural Gas	777	1,026	1,221	902	867	873
	Other	1,223	1,235	1,218	1,224	1,235	1,224
	Total	4,198	4,503	4,850	4,369	4,739	5,145
New Base Case: CAIR	Coal	2,165	2,197	2,384	2,228	2,632	3,045
	Oil/Natural Gas	807	1,069	1,247	916	871	874
	Other	1,217	1,232	1,217	1,223	1,234	1,221
	Total	4,190	4,498	4,848	4,367	4,738	5,141
Option 1	Coal	2,160	2,194	2,365	2,221	2,616	3,014
	Oil/Natural Gas	812	1,072	1,265	922	887	904
	Other	1,216	1,233	1,217	1,222	1,235	1,219
	Total	4,188	4,499	4,847	4,366	4,738	5,138

Note: Numbers may not add due to rounding.
Source: Integrated Planning Model run by EPA.

Table 32. Coal Production for the Electric Power Sector under the New Base Case (CAIR) and CAMR with EPA and EIA Assumptions for Natural Gas and Electricity Growth (Million Tons)

				EPA Assumptions			EIA Assumptions		
	Supply Area	**2000**	**2003**	**2010**	**2015**	**2020**	**2010**	**2015**	**2020**
Old Base Case	Appalachia	299	275	325	315	301	328	341	340
	Interior	131	135	161	162	173	161	182	247
	West	475	526	603	631	714	626	748	840
	National	905	936	1,089	1,109	1,188	1,115	1,271	1,428
New Base Case: CAIR	Appalachia	299	275	306	310	331	320	367	390
	Interior	131	135	164	193	219	174	207	260
	West	475	526	607	579	607	614	676	765
	National	905	936	1,077	1,082	1,156	1,109	1,250	1,415
Option 1	Appalachia	299	275	303	310	330	317	377	396
	Interior	131	135	169	194	224	179	209	269
	West	475	526	589	568	572	595	639	706
	National	905	936	1,061	1,071	1,127	1,091	1,225	1,371

Source: 2000 and 2003 data are from EIA. All projections are from the Integrated Planning Model run by EPA.

Table 33. Retail Electricity Prices by NERC Region for the Base Case (No Further

Controls), CAIR, and CAMR with EPA and EIA Assumptions for Natural Gas and Electricity Growth (Mills/kWh) ($1999)

			Base Case			CAIR			Option 1			Change from CAIR
EPA Assumptions for Natural Gas and Electricity Growth												
Power Region	**Primary States Included**	**2000**	**2010**	**2015**	**2020**	**2010**	**2015**	**2020**	**2010**	**2015**	**2020**	**2020**
ECAR (1)	OH, MI, IN, KY, WV, PA	57.4	51.7	55.2	56.1	53.8	58.5	58.0	53.9	58.7	58.1	0.2%
ERCOT (2)	TX	65.1	57.9	64.4	62.6	59.3	64.6	63.3	59.1	64.9	63.4	0.1%
MAAC (3)	PA, NJ, MD, DC, DE	80.4	59.3	69.4	72.2	61.2	71.7	72.8	61.3	72.1	72.9	0.2%
MAIN (4)	IL, MO, WI	61.2	52.6	57.8	61.0	54.0	60.3	62.0	54.1	60.5	62.3	0.5%
MAPP (5)	MN, IA, SD, ND, NE	57.4	52.8	49.3	47.6	52.9	49.6	48.0	53.0	49.6	48.2	0.5%
NY (6)	NY	104.3	82.8	87.9	88.1	83.3	88.8	88.4	83.3	89.1	88.7	0.4%
NE (7)	VT, NH, ME, MA, CT, RI	89.9	77.4	83.9	82.8	77.5	84.7	83.0	77.5	84.8	83.1	0.2%
FRCC (8)	FL	67.9	71.2	71.3	69.5	71.7	72.3	70.5	71.8	72.3	70.7	0.3%
STV (9)	VA, NC, SC, GA, AL, MS, TN, AR, LA	59.3	56.2	55.1	55.3	57.0	56.2	56.6	57.1	56.2	56.8	0.3%
SPP (10)	KS, OK, MO	59.3	54.2	57.0	56.7	54.6	57.5	57.0	54.6	57.5	57.2	0.3%
PNW (11)	WA, OR, ID	45.9	49.6	47.4	46.9	49.8	47.5	46.9	49.8	47.5	47.1	0.5%
RM (12)	MT, WY, CO, UT, NM, AZ, NV, ID	64.1	63.9	65.2	64.7	64.1	65.6	65.4	64.2	65.6	65.1	-0.4%
CALI (13)	CA	94.7	97.1	98.9	99.3	97.3	99.1	99.5	97.3	99.1	99.7	0.3%
National	Contiguous Lower 48 States	66.0	60.3	63.1	63.4	61.3	64.4	64.3	61.3	64.5	64.5	0.2%

			Base Case			CAIR			Option 1			Change from CAIR
EIA **Assumptions for Natural Gas and Electricity Growth**												
Power Region	**Primary States Included**	**2000**	**2010**	**2015**	**2020**	**2010**	**2015**	**2020**	**2010**	**2015**	**2020**	**2020**
ECAR (1)	OH, MI, IN, KY, WV, PA	57.4	53.5	59.8	57.1	55.3	61.5	58.8	55.5	61.7	59.2	0.6%
ERCOT (2)	TX	65.1	63.3	66.0	64.4	63.6	66.6	65.0	63.5	66.9	65.2	0.3%
MAAC (3)	PA, NJ, MD, DC, DE	80.4	63.1	74.7	72.8	64.0	75.4	73.7	64.0	75.6	73.7	0.0%
MAIN (4)	IL, MO, WI	61.2	54.9	63.8	62.4	55.9	65.2	63.3	56.0	65.2	63.5	0.3%
MAPP (5)	MN, IA, SD, ND, NE	57.4	52.9	49.6	48.1	53.1	49.9	48.6	53.1	50.0	48.9	0.6%
NY (6)	NY	104.3	89.0	91.3	87.8	89.1	91.9	88.8	89.1	91.7	89.0	0.2%
NE (7)	VT, NH, ME, MA, CT, RI	89.9	85.1	85.5	81.2	84.7	85.9	81.8	84.6	86.0	82.5	0.8%
FRCC (8)	FL	67.9	72.5	74.6	73.7	73.3	75.3	74.3	73.4	75.5	74.4	0.0%
STV (9)	VA, NC, SC, GA, AL, MS, TN, AR, LA	59.3	57.1	57.1	57.1	57.8	58.3	58.6	57.8	58.2	58.8	0.4%
SPP (10)	KS, OK, MO	59.3	56.2	59.5	57.9	56.7	59.7	58.1	56.7	59.9	58.7	1.0%
PNW (11)	WA, OR, ID	45.9	50.4	50.0	49.9	50.7	50.2	49.9	50.3	49.9	49.5	-0.7%
RM (12)	MT, WY, CO, UT, NM, AZ, NV, ID	64.1	66.0	67.9	66.6	66.3	68.0	66.4	66.3	68.2	66.9	0.8%
CALI (13)	CA	94.7	99.5	101.4	101.8	99.6	101.5	101.8	99.9	101.8	102.0	0.2%
National	Contiguous Lower 48 States	66.0	62.8	66.1	64.9	63.5	67.0	65.8	63.6	67.1	66.1	0.5%

Source: Retail Electricity Price Model run by EPA. 2000 prices from EIA's AEO 2003.

16 Sensitivity Analysis on the Impact of Certain States not Participating in the Trading Program on Marginal Costs

EPA conducted additional sensitivity analysis in response to the possibility that some States may choose not to participate in the CAMR cap-and-trade program. The cost-effectiveness of a cap-and-trade program under CAMR could be reduced if States that are projected to be net-sellers of allowances opted not to participate in the cap-and-trade program, as this would effectively increase the stringency of the cap for States that did choose to participate in the program. In order to examine the potential impact of this possibility, EPA conducted additional analysis, assuming that States that have filed lawsuits against the Agency and are also projected to be net-sellers of allowances in CAMR as finalized and modeled in Option 1 chose not to participate in the trading program. These include the States of California, Connecticut, Illinois, Minnesota, New Hampshire, and Pennsylvania. EPA modeled CAMR Option 1 without these States by reducing the CAMR 2010 and 2018 caps by the sum of the State budgets of these

States in both phases of the program. EPA assumed that the States not participating in the cap-and-trade program would be subject to individual State caps equal to the their respective State budgets..

The results presented in Table 34 suggest that the potential decision of the States named above to not participate in the CAMR trading program would not significantly affect marginal Hg control costs within the program.[12] Marginal control costs increase about one-tenth of 1 percent in 2010, and one-fifth of 1 percent in 2020.

Table 34. Marginal Cost of Hg Reductions under the CAMR and CAMR with Some States Choosing not to Participate in the Trading Program($/ton, in $1999)

	2010	2015	2020
Option 1	$23,200	$30,100	$39,000
Option 1 – State Sensitivity	$23,230	$30,120	$39,070

Source: Integrated Planning Model run by EPA.

17 Rationale for Cap-and-trade Approach

The flexibilities contained in a cap-and-trade program, and the incentives that it creates, result in greater cost-effectiveness relative to a command-and-control program that would require equivalent emissions reductions. That is, a cap-and-trade program achieves emissions reductions at a lower cost per unit of emissions reduction, and, by the same token, generates benefits at a lower cost per benefit, than a command-and-control program that requires equivalent emissions reductions.

A cap-and-trade program for a source category establishes a cap on total emissions from the sources in that category by, typically, requiring sources to hold one allowance for each unit of emissions and then capping the total number of allowances that the sources may hold. The fundamental reason for the greater effectiveness of a cap-and-trade program is that it allows sources that can reduce emissions inexpensively to do so and to sell excess allowances to sources that cannot. This newly created market, in theory, equates marginal costs across sources. Sources with low control costs can reduce their emissions below their allowance holdings and earn revenues from selling their excess allowances. Sources with high control costs can purchase additional allowances at a price that is lower than the cost to reduce a unit of pollution at their facility. Each source can design its own compliance strategy to minimize its own compliance costs, such as investment in emissions control technology, improved operating efficiency, fuel switching, or allowance purchase. This system is particularly effective for an industry in which sources vary greatly by age, equipment configuration, and other factors. Under such a system, sources have an economic incentive to endeavor to reduce their emissions below the number of allowances they receive because of the potential to earn revenues through allowance sales. See B. Swift, How Environmental Laws Work: An Analysis of the Utility Sector's Response to Regulation of Nitrogen Oxides and Sulfur Dioxide under the Clean Air Act, 14 Tulane Environmental Law Journal 309 (Summer 2001). Allowing allowances to be banked between time periods can reduce costs even further, by encouraging sources to maximize cost-effectiveness over a longer time horizon.

[12] This analysis does not quantify the costs to individual States of choosing not to participate in the trading program.

In contrast, a command-and-control system is typically characterized by emission rate limits that are based on a particular technology and that apply uniformly to all sources in the source category (or subcategory). This system provides no incentive for sources to achieve better results than the rate limits and, therefore, no incentive to install technology or other controls that are more effective than the technology on which the rate limits are based. Further, this system tends to preclude sources from adopting technologies or practices, such as process changes or demand-side management that may reduce emissions but do so through means other than reductions in emission rates. Finally, the limitations of this system are particularly evident in an industry in which sources vary greatly from one to another.

As was discussed in the NPR (See 69 FR 4688), a trading approach is better suited to stimulate development and adoption of new technologies than a traditional command-and-control approach because of the market value of emissions allowances. This value creates an economic incentive to continually invest in research and development for emissions control technologies that are increasingly cost-effective. In addition, a cap-and-trade system accommodates any type of technology or other method of emission reduction and accommodates varying levels of emission reduction. For these reasons, a cap-and-trade program is forward-looking in its approach to emissions control technology and methods. For example, the Acid Rain cap-and-trade Program led to unexpected innovation in fuel blending to reduce SO2 emissions and created innovation-driving competition for scrubber technologies, both of which reduced the cost of compliance. See B. Swift, "U.S. Emissions Trading: Myths, Realties, and Opportunities," in Natural Resources & Environment, American, American Bar Association, vol. 19 (Summer 2005) p. 7.

As noted above, such incentives are absent from a traditional command-and-control approach based on emissions rates, and, as a result, plants do not have an incentive to reduce below the required level. Instead, command-and-control approaches are typically designed to encourage the widespread use of proven technologies by requiring sources to meet emissions rates achievable by existing control technologies.

EPA's existing cap-and-trade programs, such as the Acid Rain Program, have demonstrated the extent to which a cap-and-trade approach can be more cost-effective than a command-and-control approach. As EPA discussed in the NPR (See 69 FR 4702), trading under the Acid Rain Program has created financial incentives for electricity generators to look for new and low-cost ways to reduce emissions and to improve the effectiveness of existing pollution control equipment at costs much lower than predicted. In this discussion, EPA noted that the Acid Rain Program has achieved emissions reductions at two-thirds the cost of achieving the same reductions under a command-and-control system.

18 Small Entity Impacts

The Regulatory Flexibility Act (5 U.S.C. § 601 et seq.), as amended by the Small Business Regulatory Enforcement Fairness Act (Public Law No. 104-121), provides that whenever an agency is required to publish a general notice of proposed rulemaking, it must prepare and make available an initial regulatory flexibility analysis, unless it certifies that the proposed rule, if promulgated, will not have "a significant economic impact on a substantial number of small entities" (5 U.S.C. § 605[b]). Small entities include small businesses, small organizations, and small governmental jurisdictions.

For the purposes of assessing the impacts of CAMR on small entities, a small entity is defined as:

(1) A small business according to the Small Business Administration size standards by the North American Industry Classification System (NAICS) category of the owning entity. The range of small business size standards for electric utilities is 4 billion kilowatt-hours of production or less;
(2) a small government jurisdiction that is a government of a city, county, town, district, or special district with a population of less than 50,000; and
(3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

Table 35 lists entities potentially affected by this proposed rule with applicable NAICS code.

Table 35. Potentially Regulated Categories and Entities[a]

Category	NAICS Code[b]	Examples of Potentially Regulated Entities
Industry	221112	Coal-fired electric utility steam generating units.
Federal Government	221112[c]	Coal-fired electric utility steam generating units owned by the federal government.
State/Local/ Tribal Government	221112[c]	Coal-fired electric utility steam generating units owned by municipalities.
	921150	Coal-fired electric utility steam generating units in Indian Country.

[a] Include NAICS categories for source categories that own and operate electric generating units only.
[b] North American Industry Classification System.
[c] Federal, state, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

Courts have interpreted the RFA to require a regulatory flexibility analysis only when small entities will be subject to the requirements of the rule.[13] In the January 30, 2004 Notice of Proposed Rulemaking (NPR) EPA determined that the proposed rule would not have a significant impact on a substantial number of small entities. However, to provide additional information to States and affected sources, EPA conduct a general analysis of the potential economic impact of CAMR on small entities.

EPA examined the potential economic impacts to small entities associated with this rulemaking based on assumptions of how the affected states will implement control measures to meet their NO_x and SO_2 budgets under the Clean Air Interstate Rule (CAIR) and their Hg budgets for EGUs under CAMR. Under CAMR, States have the option of either participating in an EPA-run trading program, or implementing their Hg budget as a strict cap on Hg emissions from EGUs. This analysis assumes that all affected States in the CAIR region choose to meet their CAIR budgets by controlling EGUs only, and that all States participate in the nationwide

[13] See Michigan v. EPA, 213 F.3d 663, 668-69 (D.C. Cir. 2000), cert. den. 121 S.Ct. 225, 149 L.Ed.2d 135 (2001). An agency's certification need consider the rule's impact only on entities subject to the rule.

Hg cap-and-trade program. This analysis does not examine potential indirect economic impacts associated with CAIR or CAMR, such as employment effects in industries providing fuel and pollution control equipment, or the potential effects of electricity price increases on industries and households. Because CAMR is implemented in conjunction with CAIR, the costs of CAMR are measured incrementally to the costs of CAIR alone.

This analysis presents the annualize cost of CAMR for the year 2020, which is two years into the second phase of the Hg cap-and-trade program, and for which the Hg emission cap is 15 tons. An important caveat to note in considering the results presented in this section is (as discussed earlier in this chapter) that EPA assumes no development in control technologies over the course of the Hg cap-and-trade program. In reality, Hg emissions control is a fast moving area with new developments nearly monthly. Actual costs may be lower than those presented since modeling assumes no improvements in the cost of mercury control technology, while in reality, control costs are expected to improve over time. As a result, this the projected costs of the Hg cap-and-trade program for 2020 presented in this analysis most certainly overstate the impact of the rule on small entities during the second phase of the program. At the same time, however, the marginal cost projected for mercury control in 2020 may also overstate the cost-savings that entities selling allowances may experience under the rule. Finally, it should be noted that during the first phase of the program, the fact that the cap is equal to co-benefits under CAIR should limit the impact of CAMR on small entities.

18.1. Identification of Small Entities

EPA used EGRID data as a basis for compiling the list of potentially affected small entities. EGRID is EPA's Emissions & Generation Resource Integrated Database, which contains emissions and resource mix data for virtually every power plant and company that generates electricity in the United States.[14] The data set contains detailed ownership and corporate affiliation information. For plants burning coal as the primary fuel, plant-level boiler and generator capacity, heat input, generation, and emissions data were aggregated by owner and then parent company. Entities with more than 4 billion kWh of annual electricity generation were removed from the list, as were municipal-owned entities serving a population greater than 50,000. Finally, for cooperatives, investor-owned utilities, and subdivisions that generate less than 4 billion kWh of electricity annually but may be part of a large entity, additional research on power sales, operating revenues, and other business activities was performed to make a final determination regarding size. Because the rule does not affect units with a generating capacity of 25 MW or less, small entities that do not own at least one coal-fired generating unit with a capacity greater than 25 MW were dropped from the data set. According to EPA's analysis, approximately 35 small entities were exempted by this provision. EPA identified a total of 81 potentially affected small entities, out of a possible 116. The number of potentially affected small entities by ownership type, and summary of projected impacts, is listed in Table 36.

[14] eGRID is available at http://www.epa.gov/cleanenergy/egrid/download.htm.

Table 36. Projected Impact of CAMR on Small Entities

EGU Ownership Type	Number of Potentially Affected Entities	Total Net Compliance Cost in 2020 Incremental to CAIR ($1999 millions)	Number of Small Entities with Compliance Costs >1% of Generation Revenues in 2020	Number of Small Entities with Compliance Costs >3% of Generation Revenues in 2020
Cooperative	21	8.5	7	1
Investor-Owned Utility	2	6.4	2	0
Municipal	48	15.2	28	11
Subdivision	8	6.3	5	2
Other	1	-0.003	0	0
Total	80	36.5	42	14

Note: The total number of potentially affected entities in this table excludes the 35 entities that have been dropped because they will not be affected by CAMR. Also, the total number of entities with costs greater than 1 percent or 3 percent of revenues includes only entities experiencing positive costs.

Source: IPM and TRUM analysis

18.2 Overview of Analysis and Results

This section presents the methodology and results for estimating the impact of CAMR to small entities in 2020 based on the following endpoints:

- annual economic impacts of CAMR on small entities and
- ratio of small entity impacts to revenues from electricity generation.

18.2.1 Methodology for Estimating Impacts of CAMR on Small Entities

An entity can comply with CAMR through some combination of the following: installing retrofit technologies, purchasing allowances, switching to a lower Hg fuel, or reducing emissions through a reduction in generation. Additionally, units with more allowances than needed can sell these allowances on the market. The chosen compliance strategy will be primarily a function of the unit's marginal control costs and its position relative to the marginal control costs of other units. Because CAMR will be implemented in conjunction with CAIR, units affected by both rules will attempt to minimize their cost of compliance over both rules, by considering Hg, SO_2, and NO_x control strategies simultaneously.

To attempt to account for each potential control strategy over the combined rules, EPA estimates compliance costs as follows:

$$C_{Compliance} = \Delta\, C_{Operating+Retrofit} + \Delta\, C_{Fuel} + \Delta\, C_{Allowances} + \Delta\, C_{Transaction} - \Delta\, R \qquad (1)$$

where C represents a component of cost as labeled, and Δ R represents the retail value of foregone electricity generation.

In reality, compliance choices and market conditions can combine such that an entity may actually experience a savings in any of the individual components of cost. Under CAIR and

CAMR, for example, EPA projects that the price of low-sulfur coal will fall as many units install scrubbers and switch away from low-sulfur coal to cheaper bituminous coal, such that many entities actually experience a reduction in fuel costs relative to the base caes as a result of lower prices due to the demand shift. Similarly, although some units will forgo some level of electricity generation (and thus revenues) to comply, this impact will be lessened on these entities by the projected increase in electricity prices under CAIR and CAMR as well as reductions in fuel costs, and those not reducing generation levels will see an increase in electricity revenues. Elsewhere, unscrubbed units burning low-sulfur coal might find it most economical to install mercury-specific controls such as ACI, and sell their surplus of Hg allowances on the market. Because this analysis evaluates the total costs along each of the four compliance strategies laid out above for each entity, it inevitably captures savings or gains such as those described. As a result, what we describe as cost is really more of a measure of the net economic impact of the rule on small entities.

For this analysis, EPA used IPM-parsed output to estimate net compliance costs at the unit level. These impacts were then summed for each small entity, adjusting for ownership share. Net impact estimates were based on the following: operating and retrofit costs, sale or purchase of allowances, and the change in fuel costs or electricity generation revenues under CAMR relative to CAIR. These individual components of compliance cost were estimated as follows:

(1) Operating and retrofit costs: Using the IPM-parsed output for the base case, CAIR, and CAMR (available in the docket), EPA identified units that install control technology under CAIR and CAMR and the technology installed. The equations for calculating retrofit costs were adopted from EPA's Technology Retrofit and Updating Model (TRUM). The model calculates the capital cost (in \$/MW); the fixed operation and maintenance (O&M) cost (in \$/MW-year); the variable O&M cost (in \$/MWh); and the total annualized retrofit cost for units projected to install FGD, SCR, SNCR, or ACI.

(2) Sale or purchase of allowances: EPA estimated the value of initial SO_2, NO_x, and Hg allowance holdings. For SO_2, units were assumed to retain their Phase II allowance allocations as determined under EPA's 1998 reallocation of Acid Rain allowances, adjusted to reflect the 50 percent reduction in 2010 and 65 percent reduction in 2015 under CAIR. Because of the resources involved in compiling allowance-holding data, the value of banked SO_2 allowances was not considered in this analysis. The implication of this is that the annual net purchase of allowances may be overstated for some units. For NO_x, the state emission budgets were assumed to be apportioned to units on a heat-input basis. Each unit was assumed to receive a share of the state NO_x emission budget equal to its share of the total state heat input for that year in the base case. This is a simplification of what is included in the model rule, which proposes allocating NO_x allowances based on heat input from 1999-2002.[15] However, states can ultimately decide

[15] A similar approach was used in regulatory impact analyses for the 126 FIP and NO_x SIP Call.

how to allocate NO_x allowances. For Hg, unit allocations were the same as those listed in the March 16, 2004 Supplemental Notice of Proposed Rulemaking.

To estimate the value of allowances holdings, allocated NOx and SO_2 allowances were subtracted from projected emissions, and the difference was then multiplied by the allowance prices projected by IPM for 2020. Units were assumed to purchase or sell allowances to exactly cover their projected NO_x and SO_2 emissions under CAIR + CAMR. For Hg, units that did not have allowances sufficient to cover projected 2020 emissions were projected to withdraw allowances from their respective Hg allowance banks if available, or else purchase the required amount of allowances. Units holding 2020 allowances in excess of projected 2020 emissions were projected to sell these excess allowances. The estimation of the size of a unit's mercury allowance bank is discussed further below.

(3) Fuel costs: Fuel costs were estimated by multiplying fuel input (MMBtu) by region and fuel-type-adjusted fuel prices ($/MMBtu) from TRUM. The change in fuel expenditures under CAMR was then estimated by taking the difference in fuel costs between CAMR and CAIR.

(4) Value of electricity generated: EPA estimated electricity generation by first estimating unit capacity factor and maximum fuel capacity. Unit capacity factor is estimated by dividing fuel input (MMBtu) by maximum fuel capacity (MMBtu). The maximum fuel capacity was estimated by multiplying capacity (MW) * 8,760 operating hours * heat rate (MMBtu/MWh). The value of electricity generated is then estimated by multiplying capacity (MW)*capacity factor*8,760*regional-adjusted retail electricity price ($/MWh).

As discussed later in this analysis, many small entities projected to be affected by CAMR do not have to operate in a competitive market environment and thus should be able to pass compliance costs on to consumers. To somewhat account for this, we incorporated the projected regional-adjusted retail electricity price calculated under CAMR in our estimation of generation revenue under CAMR.

(5) Administrative costs: Because most affected units are already monitored as a result of other regulatory requirements, EPA considered the primary administrative cost to be transaction costs related to purchasing or selling allowances. EPA assumed that transaction costs were equal to 1.5 percent of the total absolute value of a unit's allowances. This assumption is based on market research by ICF Consulting.

(6) Value of the Mercury Bank: EPA's economic analysis of CAMR suggests that a significant bank of approximately 70 tons of Hg allowances will be built up during the first phase of the cap-and-trade program. Sources will be relying heavily on this bank for compliance during the second phase of the program.

While not all sources will have banked allowances during the first phase of the program, many sources will be able to draw from this bank during the second phase and avoid or limit Hg allowance purchases. EPA estimated the size of the bank by comparing projected emissions for the years 2010-2019 with allocations for those years. This estimate assumed that small entity sources with surplus allowances in those years would bank those allowances rather than sell them on the market, and would draw from this bank in any year that they were short allowances. EPA estimated the cost of using banked allowances by taking the average cost of Hg control in the first phase of the program discounted to 2020, multiplied by the number of banked allowances used. Finally, any surplus allowances remaining in the small entity banks in 2020 were valued at the 2020 Hg allowance price.

18.2.2 Results

The potential impacts of CAMR on small entities are summarized in Table 36. All costs are presented in $1999. EPA estimated the incremental annualized net compliance cost to small entities to relative to CAIR to be approximately $37 million in 2020. This cost is driven largely by mercury allowance purchases and additional retrofits relative to CAIR. The costs to small entities in 2020 are limited, however, by the ability of approximately 30 of the 81 small entities to sell surplus 2020 and/or banked allowances in 2020.

EPA does not project that any coal-fired generation would be uneconomic to maintain relative to CAIR. This finding suggests that the extent of CAMR's adverse economic impacts beyond CAIR on small entities is limited.

EPA further assessed the economic and financial impacts of the rule using the ratio of compliance costs to the value of revenues from electricity generation, focusing in particular on entities for which this measure is greater than 1 percent. Although this metric is commonly used in EPA impact analyses, it makes the most sense when as a general matter an analysis is looking at small businesses that operate in competitive environments. However, small businesses in the electric power industry often operate in a price-regulated environment where they are able to recover expenses through rate increases. Given this, EPA considers the 1 percent measure in this case a crude measure of the price increases these small entities will be asking of rate commissions or making at publicly owned companies.

Of the 80 small entities considered in this analysis, and 116 total small entities in the affected region 42 were projected to have compliance costs greater than 1% of revenues, while 14 were projected to have compliance costs greater than 3% of revenues. As was emphasized earlier, this result is largely due to the magnitude of the projected marginal Hg control cost in 2020. A marginal cost similar to what was projected in the sensitivity analysis discussed earlier in this chapter would eliminate significant impacts. Furthermore, the majority of small entities in this analysis operate in a competitive market and thus should be able to recover their costs of complying with CAMR. It should also be emphasized that under CAMR, states, through their choice of Hg allowance allocation methodologies, can potentially mitigate adverse affects of CAIR on small entities.

The distribution across entities of economic impacts as a share of base case revenue is summarized in Table 37. Although the distributions of economic impacts on each ownership type are in general fairly tight. Entities with the lowest negative net impacts are those that have complied with the Hg rule without additional retrofits, and have a number of surplus Hg allowances for sale. On average, the impact of the rule on small entities is less than 1% of electricity generation revenues.

Table 37 Summary of Distribution of Economic Impacts of CAIR on Small Entities

EGU Ownership Type	Capacity-Weighted Average Economic Impacts as a % of Generation Revenues	Min	Max
Cooperative	0.52 %	-6.30 %	4.7 %
Investor-owned utility	1.94 %	1.48 %	2.22 %
Municipal	1.21 %	-5.30 %	6.39 %
Subdivision	1.54 %	-0.52 %	3.31 %
Other	-0.09 %	-0.09 %	-0.09 %
All	0.96 %	-6.30 %	6.4%

Source: IPM and TRUM analysis

In the cases where entities are projected to experience positive net impacts that are a high percentage of revenues, these entities generally have a shortage of Hg allowances and must purchase them on the market at the projected 2020 price. Many of these entities also reduce generation slightly, and thus generation revenues, relative to CAIR alone.

The separate components of annualized costs to small entities under CAIR and CAIR + CAMR are summarized in Table 38. Under CAMR, allowance purchases, driven largely by the marginal cost projected for Hg in 2020, as well as additional retrofits, are the most significant components of compliance cost for small entities in 2020. Also, fuel costs under for all groups with the exception of IOUs increase relative to CAIR, largely because of an increased demand for bituminous coal and the resulting higher bituminous coal price relative to CAIR. Retrofit and operating costs for subdivisions, municipals, and cooperatives increase significantly, largely because of the installation of FGD, SCR and ACI. Finally, all groups with the exception of IOUs experience an increase in electricity revenues relative to CAIR alone. This increase is largely driven by increases in the retail price of electricity relative to CAIR alone, although a few units are projected to increase generation under CAIR + CAMR. The two IOUs in this analysis experience an increased revenue loss that results largely from generation reductions relative to CAIR in 2020.

Table 38. Incremental Annualized Costs under CAMR relative to CAIR, Summarized by Ownership Group and Cost Category ($1,000,000)

EGU Ownership Type	Retrofit + Operating Cost	Net Purchase of Allowances	Fuel Cost	Lost Electricity Revenue	Administrative Cost
Cooperative	4.9	2.9	2	-1.3	0.1
IOU	-0.1	4.1	-0.6	3	0.1
Municipal	6.2	10.3	6.3	-7.6	0.1
Subdivision	5.3	0.8	0.4	-0.2	0.1
Other	0	0	0	-0.1	0.001

Note: Numbers may not add to totals in Table 36 due to rounding.

Source: IPM and TRUM analysis.

18.3 Summary of Small Entity Impacts

While EPA has certified, based on earlier analysis that was summarized in the January 30, 2004 NPR, that CAMR will not have a significant impact on a substantial number of small entities, this analysis has been conducted to provide additional understanding of the nature of potential impacts, and additional information to the states as they propose plants to meet the emissions budgets set by this rulemaking.

EPA projects an incremental impact on small entities relative to CAIR of approximately $37 million relative to CAIR. EPA also projects that no additional small entity coal capacity will be uneconomic to maintain under CAMR relative to what was projected to be uneconomic to maintain under CAIR, which is the new base case. This finding suggests that the incremental impact of CAMR on small entities is limited.

Furthermore, of the 81small entities potentially affected, and the 116 small entities with in the country with coal units included in EPA's modeling, 42 may experience compliance costs in excess of 1 percent of revenues, while 14 are projected to experience compliance costs in excess of 3 percent of revenues, based on our assumptions of how the affected states implement control measures to meet their emissions budgets as set forth in this rulemaking. As is discussed earlier in this analysis, the finding of a significant impact to some entities during the second phase of the program is largely a product of the marginal cost projected for Hg control in 2020. In reality, control costs of Hg are expected to be lower by 2020, such that allowance prices would be reduced, and significant impacts unlikely. Further, the majority of these small entities operate in cost-of-service markets where they should be able to pass on their costs of compliance to rate-payers.

Two other points should be considered when evaluating the impact of CAMR, specifically, and cap-and-trade programs more generally, on small entities. First, under CAIR, the cap-and-trade program is designed such that states determine how Hg allowances are to be allocated across units. States electing to participate in the Hg cap-and-trade program could allocate allowances in a manner that would mitigate any potential disadvantage faced by small entities. Further, States that chose to implement their State budget as a strict cap could provide some level of exemption to sources owned by small entities, and require greater reductions from other sources. Finally, it should be noted that, the use of a cap-and-trade program in general will limit impacts on small entities relative to a less flexible command-and-control program.

19 Unfunded Mandates Reform Act (UMRA) Analysis

Title II of the UMRA of 1995 (Public Law 104-4)(UMRA) establishes requirements for federal agencies to assess the effects of their regulatory actions on state, local, and Tribal governments and the private sector. Under Section 202 of the UMRA, 2 U.S.C. 1532, EPA generally must prepare a written statement, including a cost-benefit analysis, for any proposed or final rule that “includes any Federal mandate that may result in the expenditure by State, local, and Tribal governments, in the aggregate, or by the private sector, of $100,000,000 or more ... in any one year.” A “Federal mandate” is defined under Section 421(6), 2 U.S.C. 658(6), to include a “Federal intergovernmental mandate” and a “Federal private sector mandate.” A “Federal intergovernmental mandate,” in turn, is defined to include a regulation that “would impose an enforceable duty upon State, Local, or Tribal governments,” Section 421(5)(A)(i), 2 U.S.C. 658(5)(A)(i), except for, among other things, a duty that is “a condition of Federal assistance,” Section 421(5)(A)(i)(I). A “Federal private sector mandate” includes a regulation that “would impose an enforceable duty upon the private sector,” with certain exceptions, Section 421(7)(A), 2 U.S.C. 658(7)(A).

Before promulgating an EPA rule for which a written statement is needed under Section 202 of the UMRA, Section 205, 2 U.S.C. 1535, of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule.

In the NPR, EPA concluded that the proposed Hg MACT contained a Federal Mandate that may result in expenditures of $100 million or more for State, local, and Tribal governments in aggregate, or the private sector in any one year. For that reason, EPA prepared a written statement for the NPR consistent with the requirements of Section 202 of the UMRA. In today’s final rule, EPA is not directly establishing any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments. Thus, under CAMR, EPA is not obligated to develop under Section 203 of the UMRA a small government agency plan. Furthermore, in a manner consistent with the intergovernmental consultation provisions of Section 204 of the UMRA, EPA carried out consultations with the governmental entities affected by this rule.

EPA analyzed the economic impacts of the final CAMR. This analysis does not examine potential indirect economic impacts associated with CAIR, such as employment effects in industries providing fuel and pollution control equipment, or the potential effects of electricity price increases on industries and households.

This analysis presents the annualize cost of CAMR for the year 2020, which is two years into the second phase of the Hg cap-and-trade program, and for which the Hg emission cap is 15 tons. An important caveat to note in considering the results presented in this section is (as discussed earlier in this chapter) that EPA assumes no development in control technologies over the course of the Hg cap-and-trade program. In reality, Hg emissions control is a fast moving area with new developments nearly monthly. Actual costs may be lower than those presented since modeling assumes no improvements in the cost of mercury control technology, while in reality, control costs are expected to improve over time. As a result, this the projected costs of the Hg cap-and-trade program for 2020 presented in this analysis most certainly overstate the impact of the rule on government-owned entities during the second phase of the program. At the same time, however, the marginal cost projected for mercury control in 2020 may also overstate the cost-savings that entities selling allowances may experience under the rule. Finally, it should be noted that during the first phase of the program, the fact that the cap is equal to co-benefits under CAIR should limit the impact of CAMR on government entities.

19.1 Identification of Government-Owned Entities

Using eGRID data, EPA identified state- and municipality-owned utilities and subdivisions.

EPA then used IPM-parsed output to associate these plants with individual generating units. Entities that did not own at least one unit with a generating capacity of greater than 25 MW were omitted from the analysis because of their exemption from the rule. This exempts 37 entities owned by state or local governments. Thus, EPA identified 88 state and municipality-owned utilities that are potentially affected by CAIR, out of a possible 125, which are summarized in Table 39.

Table 39. Summary of Potential Impacts on Government Entities under CAMR

EGU Ownership Type	Potentially Affected Entities	Net Compliance Cost in 2020 Incremental to CAIR ($1999 millions	Number of Government Entities with Compliance Costs >1% of Generation Revenues	Number of Government Entities with Compliance Costs >3% of Generation Revenues
Subdivision	8	6.5	5	2
State	10	9.2	4	0
Municipal	70	32.2	35	12
Total	88	47.9	44	14

Note: The total number of potentially affected entities in this table excludes the 37 entities that have been dropped because they will not be affected by CAMR. Also, the total number of entities with costs greater than 1 percent or 3 percent of revenues includes only entities experiencing positive costs.

Source: IPM and TRUM analysis

19.2 Overview of Analysis and Results

After identifying potentially affected government entities, EPA estimated the impact of CAMR + CAIR, relative to CAIR alone, in 2020 based on the following:

- total impacts of compliance on government entities and
- ratio of small entity impacts to revenues from electricity generation.

The financial burden to owners of EGUs under CAMR is composed of compliance and administrative costs. This section outlines the compliance and administrative costs for the 88 potentially affected government-owned units identified in EPA modeling.

19.2.1 Methodology for Estimating Impacts of CAMR on Government Entities

The primary burden on state and municipal governments that operate utilities under CAMR is the cost of installing control technology on units to meet their Hg emission budget or the cost of purchasing allowances. An entity can comply with CAMR through some combination of the following: installing retrofit technologies, purchasing allowances, switching to a lower Hg fuel, or reducing emissions through a reduction in generation. Additionally, units with more allowances than needed can sell these allowances on the market. The chosen compliance strategy will be primarily a function of the unit's marginal control costs and its position relative to the marginal control costs of other units. Because CAMR will be implemented in conjunction with CAIR, units affected by both rules will attempt to minimize their cost of compliance over both rules, by considering Hg, SO_2, and NO_x control strategies simultaneously.

To attempt to account for each potential control strategy over the combined rules, EPA estimates compliance costs as follows:

$$C_{Compliance} = \Delta\, C_{Operating+Retrofit} + \Delta\, C_{Fuel} + \Delta\, C_{Allowances} + \Delta\, C_{Transaction} - \Delta\, R \qquad (2)$$

where C represents a component of cost as labeled, and $\Delta\, R$ represents the retail value of foregone electricity generation.

In reality, compliance choices and market conditions can combine such that an entity may actually experience a savings in any of the individual components of cost. Under CAIR and CAMR, for example, EPA projects that the price of low-sulfur coal will fall as many units install scrubbers and switch away from low-sulfur coal to cheaper bituminous coal, such that many entities actually experience a reduction in fuel costs relative to the base caes as a result of lower prices due to the demand shift. Similarly, although some units will forgo some level of electricity generation (and thus revenues) to comply, this impact will be lessened on these entities by the projected increase in electricity prices under CAIR and CAMR as well as reductions in fuel costs, and those not reducing generation levels will see an increase in electricity revenues. Elsewhere, unscrubbed units burning low-sulfur coal might find it most economical to install mercury-specific controls such as ACI, and sell their surplus of Hg allowances on the market. Because this analysis evaluates the total costs along each of the four compliance strategies laid out above for each entity, it inevitably captures savings or gains such as those described. As a result, what we describe as cost is really more of a measure of the net economic impact of the rule on small entities.

In this analysis, EPA used IPM-parsed output for the base case, CAIR, and CAMR to estimate net compliance cost at the unit level. These costs were then summed for each government entity, adjusting for ownership share. Compliance cost estimates were based on the following: operating and retrofit costs, sale or purchase of allowances, and the change in fuel costs or electricity generation revenues under CAMR relative to CAIR. These components of compliance cost were estimated as follows:

(1) **Operating and retrofit costs:** Using the IPM-parsed output for the base case, CAIR, and CAMR (available in the docket), EPA identified units that install control technology under CAIR and CAMR and the technology installed. The equations for calculating retrofit costs were adopted from EPA's Technology Retrofit and Updating Model (TRUM). The model calculates the capital cost (in $/MW); the fixed operation and maintenance (O&M) cost (in $/MW-year); the variable O&M cost (in $/MWh); and the total annualized retrofit cost for units projected to install FGD, SCR, SNCR, or ACI.

(2) **Sale or purchase of allowances:** EPA estimated the value of initial SO_2, NO_x, and Hg allowance holdings. For SO_2, units were assumed to retain their Phase II allowance allocations as determined under EPA's 1998 reallocation of Acid Rain allowances, adjusted to reflect the 50 percent reduction in 2010 and 65 percent reduction in 2015 under CAIR. Because of the resources involved in compiling allowance-holding data, the value of banked SO_2 allowances was not considered in this analysis. The implication of this is that the annual net purchase of allowances may be overstated for some units. For NO_x, the state emission budgets were assumed

to be apportioned to units on a heat-input basis. Each unit was assumed to receive a share of the state NO_x emission budget equal to its share of the total state heat input for that year in the base case. This is a simplification of what is included in the model rule, which proposes allocating NO_x allowances based on heat input from 1999-2002.[16] However, states can ultimately decide how to allocate NO_x allowances. For Hg, unit allocations were the same as those listed in the March 16, 2004 Supplemental Notice of Proposed Rulemaking.

To estimate the value of allowances holdings, allocated NOx and SO_2 allowances were subtracted from projected emissions, and the difference was then multiplied by the allowance prices projected by IPM for 2020. Units were assumed to purchase or sell allowances to exactly cover their projected NO_x and SO_2 emissions under CAIR + CAMR. For Hg, units that did not have allowances sufficient to cover projected 2020 emissions were projected to withdraw allowances from their respective Hg allowance banks if available, or else purchase the required amount of allowances. Units holding 2020 allowances in excess of projected 2020 emissions were projected to sell these excess allowances. The estimation of the size of a unit's mercury allowance bank is discussed further below.

(3) **Fuel costs:** Fuel costs were estimated by multiplying fuel input (MMBtu) by region and fuel-type-adjusted fuel prices ($/MMBtu) from TRUM. The change in fuel expenditures under CAMR was then estimated by taking the difference in fuel costs between CAMR and CAIR.

(4) **Value of electricity generated:** EPA estimated electricity generation by first estimating unit capacity factor and maximum fuel capacity. Unit capacity factor is estimated by dividing fuel input (MMBtu) by maximum fuel capacity (MMBtu). The maximum fuel capacity was estimated by multiplying capacity (MW) * 8,760 operating hours * heat rate (MMBtu/MWh). The value of electricity generated is then estimated by multiplying capacity (MW)*capacity factor*8,760*regional-adjusted retail electricity price ($/MWh).

As discussed later in this analysis, most government entities projected to be affected by CAMR do not have to operate in a competitive market environment and thus should be able to pass compliance costs on to consumers. To somewhat account for this, we incorporated the projected regional-adjusted retail electricity price calculated under CAMR in our estimation of generation revenue under CAMR.

(5) **Administrative costs:** Because most affected units are already monitored as a result of other regulatory requirements, EPA considered the primary administrative cost to be transaction costs related to purchasing or selling allowances. EPA assumed that transaction costs were equal to 1.5 percent of the total absolute value of a unit's allowances. This assumption is based on market research by ICF Consulting.

[16] A similar approach was used in regulatory impact analyses for the 126 FIP and NO_x SIP Call.

(6) **Value of the Mercury Bank:** EPA's economic analysis of CAMR suggests that a significant bank of approximately 70 tons of Hg allowances will be built up during the first phase of the cap-and-trade program. Sources will be relying heavily on this bank for compliance during the second phase of the program. While not all sources will have banked allowances during the first phase of the program, many sources will be able to draw from this bank during the second phase and avoid or limit Hg allowance purchases. EPA estimated the size of the bank by comparing projected emissions for the years 2010-2019 with allocations for those years. This estimate assumed that state and local government-owned sources with surplus allowances in those years would bank those allowances rather than sell them on the market, and would draw from this bank in any year that they were short allowances. EPA estimated the cost of using banked allowances by taking the average cost of Hg control in the first phase of the program discounted to 2020, multiplied by the number of banked allowances used. Finally, any surplus allowances remaining in the government entity banks in 2020 were valued at the 2020 Hg allowance price.

19.2.2 Results

A summary of economic impacts on government-owned entities is presented in Table 39. According to EPA's analysis, the total net economic impact on government-owned entities (state- and municipality-owned utilities and subdivisions) is expected to be approximately $48 million in 2020. This cost is driven largely by mercury allowance purchases and additional retrofits relative to CAIR. The costs to government entities in 2020 are limited, however, by the projection that 33 of the 88 entities sell surplus and/or banked allowances in 2020. In the absence of banked allowances, costs to these entities in 2020 would be greater.

EPA does not project that any coal-fired generation would be uneconomic to maintain relative to CAIR. This finding suggests that the extent of CAMR's adverse economic impacts beyond CAIR on small entities is limited.

As was done for the small entities analysis, EPA further assessed the economic and financial impacts of the rule using the ratio of compliance costs to the value of revenues from electricity generation in the base case, also focusing specifically on entities for which this measure is greater than 1 percent. EPA projects that 44 government entities will have compliance costs greater than 1 percent of revenues from electricity generation in 2020, and 12 entities are projected to have compliance costs greater than 3 percent of revenues. Entities that are projected to experience negative compliance costs under CAMR are not included in those totals. This approach is more indicative of a significant impact when an analysis is looking at entities operating in a competitive market environment. Government-owned entities do not operate in a competitive market environment and therefore will be able to recover expenses under CAIR and CAMR through rate increases. Given this, EPA considers the 1 percent measure in this case a crude measure of the extent to which rate increases will be made at publicly owned companies.

The distribution across entities of economic impacts as a share of base case revenue is summarized in Table 40. For state-owned entities and subdivisions, the maximum economic impact as a share of base case revenues is approximately 3 percent. A few municipality-owned entities experience economic impacts that are significantly higher than the capacity-weighted average for this group. In the cases where entities are projected to experience positive net costs that are a high percentage of revenues, these entities do not find it economic to retrofit and are unable to switch to a lower-sulfur coal. Thus, these entities comply primarily through the purchase of allowances and reductions in generation. Overall, the capacity-weighted average impact of the rule as a share of revenues is well under 1%.

Table 40. Distribution of Economic Impacts on Government Entities under CAMR

EGU Ownership Type	Capacity-Weighted Average Economic Impacts as a % of Generation Revenues	Min	Max
Sub-division	1.50 %	-0.52 %	3.31 %
State	0.30 %	-0.96 %	2.88 %
Municipal	0.38 %	-16.55 %	6.39 %
All	0.40 %	-16.55 %	6.39 %

Source: IPM and TRUM analysis

Additionally, a few municipal entities are projected to experience negative net costs that are a high percentage of base case generation revenues. These entities have units that are able to switch to a cheaper, lower-sulfur coal to comply with CAIR and are able to maintain or increase generation levels, thus increasing revenues. Further, entities in regions for which we project large electricity price increases relative to other regions tend to be among those at the lower end of the distribution.

The various components of annualized incremental cost under CAIR to each group of government entities are summarized in Table 41. Under CAMR, the most significant components of control costs for these entities are allowance purchases, driven largely by the marginal cost projected for Hg in 2020, as well as additional retrofits. Also, the increased demand for bituminous coal and the resulting higher bituminous coal price relative to CAIR leads to an increase in fuel costs for all groups. Retrofit and operating costs for all groups increase relative to CAIR alone, because of the installation of ACI, as well as some additional FGD and SCR. Finally, both states and municipals are projected to experience an increase in electricity generation revenues relative to CAIR alone, while subdivisions are projected to experience a slight additional drop in revenues relative to CAIR alone. Increased generation revenues are largely a result of slight increases in the retail price of electricity in most regions under CAMR, although some facilities are projected to increase generation. Subdivisions experience a loss in generation revenues because of a net decrease in electricity generation relative to CAIR that is not offset by the increase in electricity prices.

Table 41. Incremental Annualized Costs under CAMR Relative to CAIR Summarized by Ownership Group and Cost Category ($1,000,000)

EGU Ownership Type	Retrofit + Operating Cost	Net Purchase of Allowances	Fuel Cost	Lost Electricity Revenue	Administrative Cost
Subdivision	5.3	1.0	0.4	0.2	0.1
State	8.5	7.2	2.0	-8.6	0.2

Municipal	7.6	17.5	9.0	-2.1	0.3

Note: Numbers may not add to totals in Table 39 due to rounding.
Source: IPM and TRUM analysis.

19.3 Summary of Government Entity Impacts

EPA examined the potential economic impacts on state and municipality-owned entities associated with this rulemaking based on assumptions of how the affected states will implement control measures to meet their emissions. These impacts have been calculated to provide additional understanding of the nature of potential impacts and additional information to the states as they create State plans to meet the Hg emission budgets set by this rulemaking.

According to EPA's analysis, the total net economic impact on government-owned entities is expected to be approximately $48 million in 2020. These costs are driven largely by the purchase of Hg allowances and the cost of additional retrofits under the combination of CAIR and CAMR.

EPA projects that no additional government entity capacity will be uneconomic to maintain under CAMR relative to what was projected to be uneconomic to maintain under CAIR. This suggests that the incremental impact of CAMR on small entities relative to CAIR alone is limited.

Of the 88 government entities considered in this analysis and the 125 government entities that are included in EPA's modeling, 44 are projected to experience compliance costs in excess of 1 percent of electricity generation revenues in 2020, and 14 of these are projected to experience compliance costs in excess of 3% of generation revenues. may in 2015, based on our assumptions of how the affected states implement control measures to meet their emissions budgets as set forth in this rulemaking. As is discussed earlier in this analysis, the finding of a significant impact to some entities during the second phase of the program is largely a product of the marginal cost projected for Hg control in 2020. In reality, control costs of Hg are expected to be lower by 2020, such that allowance prices would be reduced, and significant impacts unlikely. Further, government entities operate in cost-of-service markets where they should be able to pass on their costs of compliance to rate-payers. The above points aside, potential adverse impacts of CAMR on state- and municipality-owned entities could be limited by the fact that the cap-and-trade program is designed such that states determine how Hg allowances are to be allocated across units. A state that wishes to mitigate the impact of the rule on state- or municipality-owned entities might choose to allocate Hg allowances in a manner that is favorable to these entities. Finally, in general, the use of cap-and-trade programs in general will limit impacts on entities owned by small governments relative to a less flexible command-and-control program.

EPA has determined that this rule may result in expenditures of more than $100 million to the private sector in any single year. EPA believes that the final rule represents the least costly, most cost-effective approach to achieve the air quality goals of this rule. The costs and benefits associated with the final rule are discussed throughout this RIA.

20 List of IPM Runs in Support of CAMR

A list of the IPM runs that were used in the various analyses done in support of the final CAMR is provided. Model output from each of the IPM runs listed in this memo is available in the CAMR docket and also on EPA's Web site at www.epa.gov/airmarkets/epa-ipm.

Table 42. Listing of Runs from the Integrated Planning Model Used in Analyses Done in

Support of the CAMR Final Rule Analyses

Run Name	Run Description
Base Case 2004	Base case model run, which includes the national Title IV SO_2 cap-and-trade program; NO_x SIP Call regional ozone season cap-and-trade program; and state-specific programs in Connecticut, Illinois, Maine, Massachusetts, Minnesota, Missouri, New Hampshire, New York, North Carolina, Oregon, Texas, and Wisconsin. This run represents conditions without the proposed CAIR.
CAIR 2004_Analysis	CAIR control strategy used for much of the analytical work for the final CAIR (includes AR/DE/NJ for annual controls and no ozone season cap and is the IPM run used for air quality modeling)
CAIR 2004_Final	Final CAIR policy (includes annual and ozone season caps for the States who contribute to PM2.5 and/or ozone nonattainment), used in Hg cost modeling
CAMR_Option 1	Final CAMR control strategy
CAMR_Option 2	CAMR option with Hg caps of 38 tons in 2010 and 15 tons in 2015
CAMR_Option 3	CAMR option with Hg caps of 38 tons in 2010, 24 tons in 2015, and 15 tons in 2018
CAMR_Sorbent Sensitivity_Option 1	CAMR run with second ACI control option in 2013 using advanced sorbents
Base Case 2004_EIA	Base Case run with EIA assumptions for the difference between natural gas prices and coal prices, as well as EIA's projection of electricity growth
CAIR 2004_EIA	CAIR run with EIA assumptions for the difference between natural gas prices and coal prices, as well as EIA's projection of electricity growth
CAMR 2004_EIA	CAMR run with EIA assumptions for the difference between natural gas prices and coal prices, as well as EIA's projection of electricity growth
CAMR 2004_States	CAMR run assuming CA, CT, IL, MN, NH, and PA choose not to participate in the trading program.
Parsed Files	
EPA base case parsed for year 2010	
EPA base case parsed for year 2015	
EPA base case parsed for year 2020	
EPA CAIR parsed for year 2020	
EPA CAMR_Option 1 parsed for year 2020	
EPA CAMR_Option 2 parsed for year 2020	
EPA CAMR_Option 3 parsed for year 2020	