<u>MEMORANDUM</u>

TO: Docket

FROM: EPA, Clean Air Markets Division

SUBJECT: Economic and Energy Impact Analysis for the Proposed Utility MACT Rulemaking

DATE: January 28, 2004

This memorandum provides the results of the economic and energy impact analysis performed for the proposed Utility MACT rulemaking. EPA used the Integrated Planning Model (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 mercury and other pollutants throughout the contiguous U.S. for the entire power system. Documentation for how the EPA has configured IPM for pollution control analysis can be found at www.epa.gov/airmarkets/epa-ipm.

This memorandum provides results for the MACT scenario following the emissions limits as outlined in the proposed rule. The proposed rule would establish emission limits for Hg depending on the rank of coal. Thus, the scenario that is analyzed here presumes the rate requirements for existing coal-fired generating units shown in Table 1 below.

Table 1
Proposed Mercury MACT Emission Limits for Existing Coal-Fired Electric Utility Steam Generating Units

Subcategories Based on Coal Rank	Rates *(lb/TBtu)*
Bituminous	2.0
Subbituminous	5.8
Lignite	9.2
Coal refuse / Waste coal	0.4
IGCC units	19.0
Note: TBtu - trillion BTUs of heat input	

Source: Proposal of Mercury MACT, signed December 15, 2003, available on the web at http://www.epa.gov/mercury/actions.htm

Projected Emissions Reductions from 1999 Level

Mercury emissions from coal-fired power generators were estimated by EPA to be 48 tons in 1999[1]. EPA has projected under its Base Case[2] that mercury emissions from the power generation sector will be further reduced in the coming years due to the NOx SIP call and Title IV Acid Rain Program. EPA projects that additional SCR (about 90 GW by 2010) and scrubbers (about 14 GW by 2010) will be installed to meet these program requirements and these installations will also reduce mercury emissions. The co-benefits associated with NOx and SO_2 controls assumed in this modeling are presented in Table A-3 of the Appendix to this document and in the IPM documentation. The levels of mercury reductions in both the Base Case and under the proposed MACT are presented in Table 2 below.

Table 2
Mercury Emissions and Reduction for the Base Case and Proposed MACT for 2010 and 2020
(*tons*)

Control Case	2010	2020
Base Case	44.80	44.69
Proposed MACT	30.16	31.34
Emission Reduction	14.64	13.35

Source: Integrated Planning Model results.

Projected Annual Costs

Total annual costs of the proposed MACT program are projected to be $1.6 billion in 2010 and $1.1 billion in 2020. These costs represent about a 1.9% increase in 2010 and 1.1% increase in 2020 of total annual electricity production costs.

The lower cost of the MACT program in 2020 stems from total fuel costs being lower than those in the Base Case. As in 2010, coal use reflects a shift away from bituminous and toward subbituminous and lignite coal, relative to the Base Case. In addition, there is fuel switching among bituminous coals. Projections for 2010 and 2020 differ in the sulfur content and cost of the bituminous coals that are being displaced. In 2010, the shift was largely away from less-expensive, high-sulfur bituminous coals. By 2020, the decrease in bituminous coal use was largely in the more-expensive, lower-sulfur coals, which led to a decrease in the overall fuel

[1] 1999 EPA Mercury ICR data, cited in http://www.epa.gov/ttn/atw/combust/utiltox/stxstate2.pdf

[2] Base Case includes Title IVAcid Rain Program, NOx SIP call and state rules finalized before March 1, 2003.

costs. Also, while the proposed MACT rule is expected to result in a very slight increase in gas prices in 2010, by 2020 this effect is largely attenuated.[3]

Notably, production costs are only one component of the final retail electricity prices seen by consumers, and on average, make up from one-third to one-half of regional electricity prices. Costs stemming from the transmission and distribution of electricity make up the remainder. Thus a more meaningful measure of the impact of the rule is the price effect presented in the section of this memo discussing retail prices.

Projected Control Technology Retrofits

In 2010, compliance with the MACT program is projected to be primarily through the installation of activated carbon injection (ACI). Table 3 shows that about 63 GW of coal-fired capacity is projected to install ACI. In addition, 1 GW of scrubbers and 2 GW of SCR are also projected to be installed.

While IPM relied on the use of ACI to demonstrate compliance, ACI is not a technology that is available for use in setting the MACT floor. The MACT floor rates (utilized in IPM) were dependent only on demonstrated, commercially-available technologies that are currently in use by coal-fired electric generation units (e.g., wet scrubbers and fabric filters).

Table 3
Projected Retrofits of ACI by Coal Rank for the Proposed MACT in 2010

Coal Rank	Retrofit Type	Capacity (MW)
Bituminous	90% Removal ACI	55,197
	60% Removal ACI	3,472
Subbituminous	90% Removal ACI	395
	60% Removal ACI	3,925
Lignite	90% Removal ACI	60
	60% Removal ACI	30
Total		63,079

Source: Integrated Planning Model results.

[3] Integrated Planning Model results.

Projected Hg Emissions Reductions

When the emissions rates developed in today's rule are applied to current coal use (based on the 1999 EPA ICR), emissions are projected to be 34 tons. Based on modeling, total emissions from affected coal-fired power plants are projected to be 30 tons in 2010 and 31 tons in 2020 (see Table 4). However, EPA believes that the model over-estimates reductions in this analysis and that emissions are likely to be much closer to the calculated level of 34 tons. This is further discussed in the "Limitations of the Analysis" section of this memo.

Table 4
Projected Mercury Emissions by Coal Rank
(tons)

Coal Rank	Base Case		Proposed MACT		
	2010	***2020***	***2010***	***2020***	***2010 Rate (lb/TBtu)***
Bituminous	27.10	25.78	12.25	12.18	1.71
Subbituminous	14.33	15.43	14.43	15.60	4.86
Lignite	3.37	3.48	3.48	3.56	6.70
Total	44.80	44.69	30.16	31.34	

Source: Integrated Planning Model results.

Emissions Reductions and Associated Costs

Most of the incremental costs projected under the proposed MACT rule are associated with bituminous-fired coal units, as can be seen in Table 5. This is a direct consequence of the emission limits established by the proposed MACT rule, which are relatively much tighter for bituminous coal-fired units than they are for subbituminous or lignite-fired units.

Table 5 **2010 Proposed Mercury MACT Emissions Reductions and Incremental Annual Costs by Coal Rank Relative to Base Case**		
	Hg (tons reduced)	**Annual Cost (million $1999)**
Bituminous	15.2	$1,551
Subbituminous	-0.4	$47
Lignite	-0.1	$2
Total	14.6	$1,600

Source: Integrated Planning Model results.

Due to increased generation and coal-switching, emissions from subbituminous-fired and lignite-fired units are projected to increase slightly over the Base Case. Table 6 illustrates how, as a result of the proposed MACT, coal use in 2010 is expected to shift away from bituminous coal and towards increased use of subbituminous and lignite coal.

Table 6 **Coal Use in 2010 by Coal Rank** ***(in TBtu)***			
	Base Case	**Proposed MACT**	**Percent Change from Base Case**
Bituminous	14,818	14,481	-2.3%
Subbituminous	5,722	5,989	4.7%
Lignite	989	1,040	5.1%

Source: Integrated Planning Model results.

Table 7 shows that in 2010, NOx and SO_2 emissions are projected to be reduced in comparison to Base Case emissions projections. These projected reductions are due to the reliance on some SO_2 and NOx controls and coal-switching to achieve mercury reductions. When compared to the Base Case, there is also a projected shift (about 6% of bituminous coal use measured in TBtus) from higher-mercury, higher-sulfur bituminous coals towards lower-mercury, lower-sulfur bituminous coals, which results in SO_2 emissions reductions. In addition, some units are projected to use SO_2 controls (scrubbers) to comply with the MACT (about 1 GW). Projected NOx emissions reductions from the Base Case are a result of seasonal NOx controls being operated annually in the MACT case (about 90 GW of SCR operate annually) and the addition of 2 GW of SCR to achieve mercury control. The existence of NOx and SO_2 trading market (for the NOx SIP call and Acid Rain program) would affect the choices for mercury compliance. The value of the NOx and SO_2 allowance provides an economic incentive for control options that reduce NOx and SO_2 emissions in addition to reductions in Hg emissions.

Table 7 Approximate Emissions Reductions and Incremental Annual Costs by Control Option from Base Case in 2010 for Proposed MACT				
	Hg (tons)	**SO_2 (1,000 tons)**	**NOx (1,000 tons)**	**Annual Cost (million $1999)**
ACI (60% removal)	1.0	--	--	$75
ACI (90% removal)	8.8	--	--	$990
New SCR	0.2	--	75	$25
Annual use of existing SCR	1.3	--	824	$135
New FGD	0.5	194	--	$40
Coal switching	2.8	397	--	$365
Total	14.6	591	899	$1,627

Note: Since there is an emissions cap on SO_2, these incremental reductions reflect a shift in emissions from 2010 to other year(s).
Note: Numbers may not add due to rounding errors.

Source: Calculations and estimates based on Integrated Planning Model results

Total projected state-level emissions for mercury, NOx and SO_2 for both the Base Case and the proposed MACT Policy case are included in Appendix Tables A-1 and A-2 respectively, at the end of this memo.

It should be noted that other regulatory actions that are likely to occur over this time period would likely realize much of the SO_2 and NOx reductions projected in this analysis. The proposed IAQR, for example, would realize substantially greater reductions in NOx and SO_2. In addition, technology control choices for mercury would likely be significantly affected by the requirements of the IAQR. This analysis has not taken into account the interactions that may result between this rulemaking and the IAQR.

Projected Generation Mix

The total amount of coal-fired generation and natural gas-fired generation is projected to remain relatively unchanged by the MACT program, as can be seen in Table 8 below.

Relative to the Base Case, about 500 MW of coal-fired capacity is projected to be uneconomic to maintain and about 75 MW is projected to re-power to natural gas by 2010. The uneconomic coal plants are likely also affected by the overbuild of new gas-fired combined cycle plants since 2000. The IPM model can determine that specific generating units are uneconomic to maintain, based on their fuel, operating and fixed costs, and whether they are needed to meet both demand and reliability reserve requirements. In practice, units projected to be uneconomic to maintain may be “mothballed”, actually retired, or kept in service to ensure transmission reliability in certain parts of the grid. Our modeling is unable to distinguish between these potential outcomes.

Table 8 **Electricity Generation in 2010** ***(1,000 Gwh)***		
Fuel	**Base Case**	**Proposed MACT**
Coal	2,163	2,162
Oil/Natural Gas	852	854
Other	1,180	1,180

Note: Base Case results shown here may differ slightly from other EPA Base Case results due to a different aggregation of run-years.

Source: Integrated Planning Model results.

Projected Coal Production for Electric Power Sector

Table 9 shows the projected changes in regional coal use by the power sector in 2010 under the proposed MACT, relative to the Base Case. There is a noticeable shift, in 2010, from Appalachian coals (which are generally bituminous and thus burned by plants with more stringent MACT limits) towards Western coals. Due to Western coals' lower heat content, more tons of coal need to be burned to make up for the projected lost Appalachian coal consumption.

Table 9 **Coal Use by Electric Power Sector** ***(million tons)***			
Coal Supply Region	**2000 Historical**	**2010 Base Case**	**2010 Proposed MACT**
Appalachia	299	315	304
Interior	131	177	177
West	475	536	554
National	905	1,028	1,034
Note: Base Case results shown here may differ slightly from other EPA Base Case results due to a different aggregation of run-years.			

Source: Integrated Planning Model results. Historical data from EIA Coal Industry Annual 2000, represents coal deliveries.

Projected Retail Electricity Prices

In 2020, retail electricity prices are projected to still be below 2000 prices. When compared to 2010 projections of the Base Case, electricity prices are projected to increase very slightly - only about one-half a percent in 2010 and about two-tenths of a percent in 2020. Retail electricity prices by power region are provided for the both the Base Case and the proposed MACT case for the years 2010 and 2020 in Table 10 below.

Table 10
Retail Prices ***(Mills Per Kwh - 1999$)***

Power Region	Main States Included	2000	Base Case		Proposed MACT		% Price Change	
			2010	2020	2010	2020	2010	2020
ECAR	OH, MI, IN, KY, WV, PA	57.4	51.2	56.6	52.1	57.0	1.7%	0.8%
ERCOT	TX	65.1	54.3	66.3	54.3	66.3	0.1%	0.1%
MAAC	PA, NJ, MD, DC, DE	80.4	58.5	74.0	58.8	74.1	0.6%	0.2%
MAIN	IL, MR, WI	61.2	53.0	62.5	53.3	62.7	0.5%	0.2%
MAPP	MN, IA, SD, ND, NE	57.4	54.5	49.0	54.6	48.9	0.2%	-0.2%
NY	NY	104.3	80.4	90.6	80.8	91.0	0.5%	0.4%
NE	VT, NH, ME, MA, CT, RI	89.9	71.8	83.9	72.0	84.2	0.3%	0.4%
FRCC	FL	67.9	71.1	68.6	71.5	68.8	0.5%	0.3%
STV	VA, NC, SC, GA, AL, MS, TN, AR, LA	59.3	55.9	54.7	56.3	54.9	0.8%	0.4%
SPP	KS, OK, MO	59.3	51.7	56.3	51.9	55.6	0.4%	-1.3%
PNW	WA, OR, ID	45.9	50.2	48.5	50.2	48.5	0.2%	0.0%
RM	MT, WY, CO, UT, NM, AZ, NV, ID	64.1	63.1	65.6	63.4	65.7	0.4%	0.2%
CALI	CA	94.7	96.1	97.5	96.2	97.5	0.1%	0.0%
National	Contiguous Lower 48 States	66.0	59.6	63.9	60.0	64.1	0.6%	0.2%

Source: EPA Retail Electricity Pricing Model with inputs from IPM.

Projected Fuel Price Impacts

The projected changes in fuel prices (prior to transport for coal, and price at the Henry Hub for natural gas) are provided in Table 11. As can be seen, the proposed MACT policy is expected to result in very little, if any, changes in fuel prices.

Table 11 Average Coal Mine Mouth and Henry Hub Natural Gas Prices *(1999$)*					
	2000	**Base Case**		**Proposed MACT**	
		2010	***2020***	***2010***	***2020***
Coal Mine Mouth (US$/MMBtu)	0.80	0.60	0.55	0.60	0.53
Henry Hub (US$/MMBtu)	4.15	2.97	2.87	2.99	2.87

Source: Integrated Planning Model results; 2000 natural gas and coal data from Platts COALdat and GASdat.

Sensitivity of Assumptions for Natural Gas Prices and Electricity Growth

Sensitivity analysis was performed using the Energy Information Agency's (EIA) assumptions for natural gas prices and electricity growth in place of those used by EPA in the primary analysis. These particular assumptions involve higher natural gas prices in 2010 and in 2020 and project electricity growth of 1.86% a year, rather than EPA projected growth of 1.55%. In analyzing the sensitivity analysis output the EPA found:

- Annual costs of proposed MACT are expected to be $1.6 billion in 2010 and $1.2 billion in 2020. Projected total annual costs are almost identical to those in the primary analysis in 2010, and total annual costs are projected to increase less than 10% in 2020 relative to those using EPA assumptions (See Table 12).

Table 12 Comparison of Sensitivity Analysis Results of Projected Annual Costs to EPA Primary Case *(billion $1999)*		
	2010	**2020**
Proposed MACT	1.6	1.1
Proposed MACT with EIA assumptions for electricity demand growth and natural gas prices	1.6	1.2

Source: Integrated Planning Model results

- As can be noted in Table 13, coal-fired generation increases under EIA assumptions, with new coal-fired capacity projected: 5 GW in 2010 and 107 GW in 2020. Almost no existing coal units are found to be uneconomic.
- Increased projected mercury emissions (relative to the MACT analysis under EPA primary case assumptions) accompany the increases in new coal-fired capacity and generation, as can be seen in Table 14.

For the same reasons as noted earlier and discussed in the "Limitations" section below, analysis of the proposed MACT using EIA assumptions may underestimate expected mercury emissions.

Table 13 **Comparison of Sensitivity Analysis Results of Projected Electricity Generation to EPA Primary Case in 2010** ***(1,000 Gwh)***				
	Proposed MACT for Primary Case		**Proposed MACT with EIA assumptions for growth and gas**	
	2010	***2020***	***2010***	***2020***
Coal	2,162	2,339	2,254	3,698
Oil/Natural Gas	854	1,807	954	802
Other	1,180	1,175	1,181	1,179

Source: Integrated Planning Model results

Table 14 **Comparison of Sensitivity Analysis Results of Projected Mercury Emissions to EPA Primary Case** ***(tons)***		
Projected Hg Emissions (tons)	**2010**	**2020**
Proposed MACT Primary Case	30.10	31.31
Proposed MACT with EIA assumptions for electricity demand growth and natural gas prices	31.91	34.61

Source: Integrated Planning Model results.

Limitations of Analysis

Although the model can be equipped to analyze rate-based limits on the power sector, EPA's configuration of IPM is more suitable for analyzing cap-and-trade programs and historically has been used by EPA to analyze such programs. Control technology choices in the model were developed by EPA primarily to address cap-and-trade options. In the case of mercury control technology, the model allows for reductions of ACI only at the 60% and 90% level (rather than the range of 60 to 90%). This choppiness in the model may lead to as much as 2 tons of over compliance by the bituminous units. In addition, the modeling assumes a range of mercury contents for different grades of coal, but due to averaging, may not fully capture all mercury contents of all possible coal choices.

The mercury content of coal used in the modeling was developed using the more than 40,000 data points collected in EPA's 1999 Mercury ICR. To make this data usable in EPA's modeling, these data points were first grouped by IPM coal types and IPM coal supply regions. (IPM coal types divide bituminous, subbituminous, and lignite coal into different grades based on sulfur content.) Cluster analysis and statistical averaging were used to provide a range of mercury contents for each IPM coal type by supply region and sulfur content. Consequently, for each type of coal in each coal supply region, there are from 1 to 3 emissions factors that characterize the mercury content for that type of coal. Please see IPM documentation, Chapter 4 for further information on mercury content of coal: www.epa.gov/airmarkets/epa-ipm.

Therefore, when modeling a facility specific limit, the averaging of mercury contents for different grades of coal may underestimate emissions because it may not fully capture all mercury contents of all possible coal choices. This factor along with the mercury technology choice options available (discussed earlier) could result in an underestimate of mercury emissions from the model.

Other limitations of this modeling analysis are that it presents a single set of resulting outputs from a single set of input assumptions that represent EPA' best technical judgements regarding the values of these variables. Sensitivity analysis with EIA gas price and electricity growth assumptions provides insight from an alternate set of input assumptions in these two key areas. This analysis yielded similar results with regards to some outputs (such as costs of the proposed MACT) program, and differing results with regards to other outputs (such as the projected Mercury Emissions in 2010 and 2020). Additional sensitivities, both on these variables and on other input parameters, would provide additional information about the robustness of the results.

Another area of uncertainty is the performance of mercury control removal systems, like the one assumed in the modeling, activated carbon injection (ACI). ACI systems with added pulse-jet fabric filters 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 electric generating plants. In fact, a key limitation of this modeling analysis is that it does not take into account the potential for advancements in the capabilities of mercury control technology and reductions in their costs over time, so that the results for 2020 are less certain.

As configured, the IPM model also does not take into account demand response, i.e. consumer reaction to the levels of electricity prices. The increased retail electricity prices shown on Table 10 would prompt end-users, to curtail (to some extent) their use of electricity and encourage them to use substitutes[4]. These responses would lessen the demand for electricity, lowering electricity production costs and prices and reducing generation and emissions.

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

Energy Impact

According to *Executive Order 13211: Actions that Significantly Affect Energy Supply, Distribution, or Use*, this proposed rule is significant because it has a greater than a 1% impact on the cost of electricity production and because it results in the retirement of greater than 500 MW of coal-fired generation, this regulation is significant. It should be noted that EPA has proposed a trading program to achieve mercury reduction as an alternative to the MACT standard, which is a command and control regulation. The relative flexibility offered by a trading program may ease the impact on energy production.

APPENDIX

Table A-1 **Base Case Projected State Level Emissions for Hg, NOx (summer and total) and SO_2 in 2010**				
State	***Hg (tons)***	***Summer NOx***	***Total NOx***	***Total SO_2***
		(thousand tons)		
Alabama	1.59	39	131	458
Arizona	0.48	35	79	48
Arkansas	0.93	23	51	123
California	0.04	1	2	11
Colorado	0.22	35	80	70
Connecticut	0.10	1	3	6
Delaware	0.19	4	10	46
Florida	0.82	62	140	233
Georgia	1.88	25	148	609
Illinois	1.89	44	170	591
Indiana	2.13	60	236	656
Iowa	0.78	36	82	152
Kansas	0.97	45	101	64
Kentucky	1.31	36	192	369
Louisiana	0.73	21	46	113
Maine	0.01	0	1	3
Maryland	1.28	10	60	229
Massachusetts	0.20	3	8	16
Michigan	1.42	36	118	375
Minnesota	0.69	43	101	85
Mississippi	0.23	18	42	73
Missouri	1.70	44	132	281
Montana	0.32	16	37	18
Nebraska	0.57	25	57	97
Nevada	0.21	14	36	17
New Hampshire	0.05	1	3	7
New Jersey	0.57	4	27	40
New Mexico	0.59	34	76	48
New York	1.23	18	47	197
North Carolina	0.93	22	60	191
North Dakota	1.11	33	78	160
Ohio	3.58	61	261	1,183
Oklahoma	1.19	34	76	133
Oregon	0.09	4	9	15
Pennsylvania	4.78	45	206	868
South Carolina	0.56	15	64	199
South Dakota	0.11	5	10	35
Tennessee	0.94	22	103	306
Texas	3.45	66	148	489
Utah	0.15	31	69	31
Virginia	0.60	14	53	186
Washington	0.24	9	21	6
West Virginia	1.96	26	155	539
Wisconsin	1.30	46	104	200
Wyoming	0.66	39	89	46
Total	***44.79***	***1,204***	***3,723***	***9,625***

Note: Base Case results shown here may differ slightly from other EPA Base Case results due to a different aggregation of run-years. Source: Integrated Planning Model results.

Table A-2 **Proposed MACT Projected State Level Emissions for Hg, NOx (summer and total) and SO_2 in 2010**				
	Hg (tons)	***Summer NOx***	***Total NOx***	***Total SO_2***
State		***(thousand tons)***		
Alabama	0.94	45	103	434
Arizona	0.33	35	79	48
Arkansas	0.86	23	51	123
California	0.05	1	2	11
Colorado	0.19	35	80	70
Connecticut	0.04	1	3	6
Delaware	0.06	4	8	38
Florida	0.62	52	117	237
Georgia	1.39	26	61	609
Illinois	1.52	47	129	513
Indiana	1.61	58	138	545
Iowa	0.77	35	83	154
Kansas	0.93	45	99	68
Kentucky	0.68	34	81	346
Louisiana	0.66	21	46	113
Maine	0.00	0	1	3
Maryland	0.32	10	24	233
Massachusetts	0.09	3	7	15
Michigan	1.33	39	94	377
Minnesota	0.69	43	99	88
Mississippi	0.18	18	42	73
Missouri	1.53	44	108	283
Montana	0.32	16	37	18
Nebraska	0.53	25	56	96
Nevada	0.12	14	35	16
New Hampshire	0.04	1	3	7
New Jersey	0.11	4	10	38
New Mexico	0.59	34	76	48
New York	0.25	17	39	188
North Carolina	0.72	21	60	191
North Dakota	1.12	35	80	172
Ohio	1.42	55	147	912
Oklahoma	1.09	34	76	133
Oregon	0.09	4	9	15
Pennsylvania	1.16	42	108	744
South Carolina	0.31	15	35	199
South Dakota	0.13	5	12	41
Tennessee	0.49	22	51	306
Texas	3.45	66	148	557
Utah	0.14	31	69	31
Virginia	0.32	14	33	183
Washington	0.24	9	21	6
West Virginia	0.92	27	71	502
Wisconsin	1.18	46	104	200
Wyoming	0.66	39	89	46
Total	30.17	1,195	2,824	9,034

Note: Since there is an emissions cap on SO_2, these incremental reductions reflect a shift in emissions from 2010 to other year(s). Source: Integrated Planning Model results.

Table A-3 EPA Mercury Removal Assumptions for Pollution Control Equipment (% removal from the Hg content of coal)			
Name for Control(s)	**Bit % removal**	**Subbit % removal**	**Lignite % removal**
PC/CS-ESP	36%	3%	0%
PC/CS-ESP/FGD	66%	16%	44%
PC/CS-ESP/FGD-Dry	36%	35%	0%
PC/CS-ESP/SCR/FGD	90%	66%	44%
PC/FF	89%	73%	0%
PC/FF/FGD	97%	73%	0%
PC/FF/FGD-Dry	95%	25%	0%
PC/FF/SCR/FGD	90%	85%	44%
PC/FGD	42%	30%	0%
PC/FGD-Dry	40%	15%	0%
PC/HS-ESP	10%	6%	0%
PC/HS-ESP/FGD	42%	20%	0%
PC/HS-ESP/FGD-Dry	40%	15%	0%
PC/HS-ESP/SCR/FGD	90%	25%	0%

Note: PC: Pulverized Coal,
CS-ESP: Cold side electrostatic precipitator,
HS-ESP: Hot side electrostatic precipitator,
FGD: Flue Gas Desulfurization - Wet,
FGD-Dry: Flue Gas Desulfurization - Dry,
SCR: Selective Catalytic Reduction,
FF: Fabric Filter

Source: Documentation of EPA Modeling Applications using the IPM model (www.epa.gov/airmarkets/epa-ipm)