The Projected Impacts of Mercury Emissions Reductions on Electricity Prices in Indiana

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1. Introduction

This paper examines the impact of various mercury emissions control scenarios on the projected prices of electricity in the state of Indiana. The scenarios represent different methods for achieving the reductions in emissions mandated by the United States Environmental Protection Agency (EPA) under its Clean Air Mercury Rule (CAMR) and an alternate, more stringent, reductions requirement as proposed by the Hoosier Environmental Council (HEC). The analyses were performed using a traditional regulation forecasting model that equilibrates between price and demand. Thus, the effects of price changes on demand levels were captured. Price impacts are presented at an overall average level as well as by customer class. The impacts of various assumptions made in the selection of the scenarios are analyzed. This paper does not attempt to compare the cost of emissions controls to the benefits of reduced emissions.

The price projections here are an average retail regulated rate paid by the consumer. Therefore, non-utility generators are not included. While the State Utility Forecasting Group (SUFG) models both the investor-owned and not-for-profit utilities in the state, the prices for the not-for-profit utilities are only known at the wholesale level (i.e., the price at which the utility sells to its member cooperative or municipal member). Thus, the price projections are only for the investor-owned utilities.

The emissions control scenarios included here were developed using a different set of electricity usage growth assumptions than those SUFG used for its *Indiana Electricity Projections: The 2005 Forecast*. Since some of the costs modeled are included per unit of output for the generator, this results in total costs being somewhat different from those in the original scenarios. The results presented here are subject to a number of assumptions regarding the compliance strategies used by the utilities to meet the mercury standards, the capital and operating costs associated with emissions control devices, the future market price of emissions allowances, and any reduction in overall plant efficiency resulting from the addition of pollution control devices. As with any forecast of unknown events, there is a degree of uncertainty surrounding these assumptions. A total of four alternative scenarios (two for each of the CAMR and HEC restrictions levels) are presented that were developed using different sets of assumptions.

2. Background

Mercury is found naturally in the earth, either in its elemental form or as an organic or inorganic compound. Some amount of mercury is contained in coal and is released into the atmosphere when the coal is burned. Over time, airborne mercury is deposited on the earth's surface, where it eventually collects in waterways. It can then be converted by microorganisms into a highly toxic form, methylmercury. Methylmercury is then passed up the food chain and is known to build up in certain types of fish and shellfish. High levels of mercury exposure in humans can damage the brain, heart, lungs, kidneys, and immune system. Furthermore, methylmercury may harm the nervous systems of unborn and young children, leading to learning problems [1].

Due to its large reserves of Illinois Basin coal, Indiana depends quite heavily on coal as a fuel source for electricity generation. 74 percent of the electric power generating capacity in the state is coal-fired and over 94 percent of the electricity generated in-state is derived from coal. As a result of this reliance on coal, as of 2004 Indiana ranked fourth in the United States in the amount of NO_x emitted annually and third in SO_2 [2]. Therefore, mercury emissions reduction regulations may significantly affect Indiana.

EPA Regulations

Table 1 summarizes the main legislation under which the EPA derives its authority. Under these laws, the EPA issues regulations regarding various emissions and timelines for meeting the regulations. The regulations are often legally challenged and revised as needed in response to court decisions.

1963 Clean Air Act (Original)	
1967 Clean Air Act Amendments	• Requires New Source Performance Standards (NSPS)
1970 Clean Air Act Amendments	• Requires National Ambient Air Quality Standards (NAAQS) • Required State Implementation Plans (SIPs) to achieve NAAQS • Requires National Emissions Standards for Hazardous Air Pollutants (NESHAPs) • Mandates New Source Reviews in non-attainment areas
1977 Clean Air Act Amendments	• Prevention of Significant Deterioration (PSD) of air quality
1990 Clean Air Act Amendments *(complete rewrite of the old Clean Air Act)*	• Revises the Titles and requires EPA to issue 175 new regulations, 30 guidance documents, and 22 reports • Requires EPA to establish interstate air pollution transport regions • Mandates maximum achievable control technology (MACT) for 189 airborne toxics by 2003 • Mandates reduction of sulfur dioxide (SO_2) emissions to an annual maximum of 8.9 million tons per year by 2000 • Requires EPA to establish an allowance trading and tracking system for SO_2 emissions • Mandates permit and emissions fee system for acid rain emissions • Basis for regulations including two phase SO_2 reduction program, Title IV nitrogen oxides (NO_x) reductions, NAAQS NO_x reductions, 2005 Clean Air Interstate Rule, and 2005 Clean Air Mercury Rule

Table 1. Major U.S. Laws and Regulations Regarding Air Emissions [3]

In March 2005, the EPA promulgated new regulations affecting electric power plant emissions. The Clean Air Interstate Rule (CAIR) lowers allowed emissions of SO_2 and NO_x by roughly 56 percent and 68 percent, respectively, from currently allowed levels. CAIR is a cap and trade type program for SO_2 and NO_x emissions with new emissions caps to be fully implemented in two phases. The first phase takes place in 2009 (NO_x) and 2010 (SO_2), and the second phase in 2015 for both SO_2 and NO_x. In the spring of 2005, the EPA also finalized CAMR. The mercury rule is also a cap and trade, two-phase rule and is projected to reduce mercury emissions from electric power plants by approximately 70 percent from 1999 levels by 2018. The first phase of CAMR depends upon the co-benefits of control measures implemented under phase one of CAIR, as the control measures used to remove SO_2 and NO_x will also remove some mercury. The second phase of CAMR is expected to require additional mercury specific control measures. In an earlier report, SUFG focused on CAIR and did not attempt to measure the impact of the second phase mercury restrictions of CAMR [4]. This report looks at the combined impacts of CAIR and CAMR.

Compliance Options

The compliance options available to fossil generators fall into four distinct categories: emission control technologies, fuel switching, the use of emission allowances, and the retirement of affected generating units. Possible emission control technologies modeled include selective catalytic reduction (SCR) systems and flue gas desulfurization (FGD) systems, activated charcoal injection (ACI), and activated charcoal injection with a fabric filter (ACI+FF). The use of advanced sorbents, which is in the developmental phase, is not included in the scenarios modeled for this report.

In SCR systems, ammonia vapor is used as the reducing agent and is injected into the flue gas stream downstream of the boiler. The mixture passes over a catalyst, reducing the NO_x to nitrogen and water. FGD systems inject a sorbent, often crushed limestone, into the exhaust stream. The sorbent reacts with the SO_2, thus removing it from the exhaust gas and producing gypsum. While SCRs and FGDs are primarily used to control NO_x and SO_2, respectively, they also reduce mercury emissions. Installation of SCRs are included in some of the scenarios modeled for this report, while FGD installations are not.

ACI is a post-combustion technology that involves injecting activated charcoal in powder form to the flue gas. Mercury in the flue gas binds to the activated charcoal, which is then captured by a particulate control device, such as an electrostatic precipitator or fabric filter. Fabric filters are generally more efficient in removing mercury in conjunction with ACI. Both ACI and ACI+FF are included in the scenarios modeled for this report.

Fuel switching involves replacing coal or oil as a source of fuel with natural gas to lower mercury emissions or switching to a coal with lower mercury content. Fuel switching can involve a complete switch to a different fuel or partial fuel switching. The costs associated with fuel switching vary greatly depending on the boiler size and design as well as access to natural gas or different types of coal, which may result in higher fuel costs. Fuel switching was not used as a method for reducing mercury emissions in any of the scenarios modeled for this report.

Retirement may be an option for older, smaller generating units where the cost associated with installing an emission control device or switching to a different fuel exceeds the expected economic benefit of keeping the unit in operation. Retirement was not used as a method for reducing mercury emissions in any of the scenarios modeled for this report, although some older, smaller units are assumed to be retired during the analysis period.

All scenarios modeled for this analysis include the installation of continuous emissions monitoring systems (CEMS). The cost and required number of CEMS installations vary from one scenario to another. For instance, the scenarios based on the CAMR restrictions require that CEMS be installed on the effluent, since CAMR limits the total amount of mercury emitted. Under the HEC restrictions scenarios, CEMS must be installed for both the effluent and the incoming fuel, since these restrictions use a minimum removal efficiency.

Rather than setting a fixed maximum amount of mercury emissions, the HEC proposal sets a minimum removal efficiency. It requires that either a maximum mercury output of 0.6 pounds per trillion British thermal units (Btu) of fuel input or 90 percent of the mercury in the fuel be removed prior to being emitted. The HEC restrictions apply for each generating station individually, with the more readily achievable of the two options applying. Thus, the 70 percent reduction associated with CAMR should not be compared directly to the 90 percent removal under the HEC proposal. The HEC proposal is more stringent than is required by EPA, with a greater impact on electricity rates.

3. Methodology

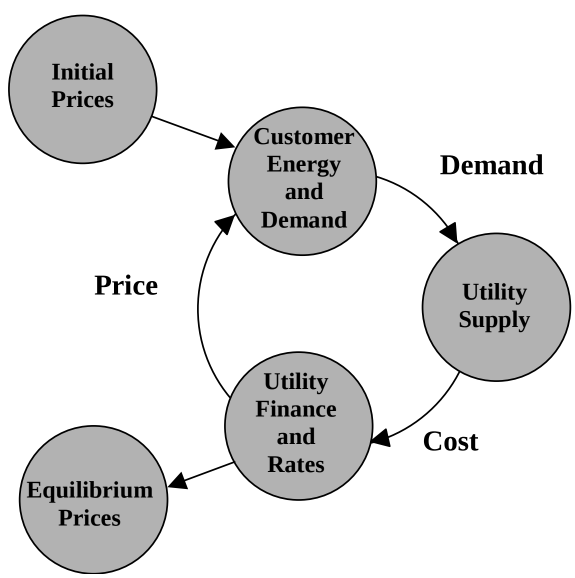
The analyses were performed for the five investor-owned utilities (Indiana Michigan Power Company, Indianapolis Power & Light Company, Northern Indiana Public Service Company, Duke Energy Indiana, and Southern Indiana Gas & Electric Company) and three major not-for-profit entities (Hoosier Energy Rural Electric Cooperative, Indiana Municipal Power Agency, and Wabash Valley Power Association) that supply electric power to Indiana customers. The statewide electricity prices reported here were determined using energy-weighted averages of the five investor-owned utilities for the residential, commercial, and industrial sectors as well as for all customer groups combined.

To determine the impacts on prices of various mercury emissions restrictions, scenarios were analyzed using a traditional regulation forecasting model developed by the State Utility Forecasting Group (SUFG) [5]. This model projects electric energy sales and peak demand as well as future electric rates given a set of exogenous factors. These factors describe the future of the Indiana economy and prices of fuels that compete with electricity in providing end-use services or are used to generate electricity. Combinations of econometric and end-use models are used to project electricity use for the major customer groups -- residential, commercial, and industrial. The modeling system predicts future electricity rates for these sectors by simulating the cost-of-service based rate structure traditionally used to determine rates under regulation. In this type of rate structure, ratepayers are typically allocated a portion of capital costs and fixed operating costs based on the customers' service requirements and are assigned fuel and other variable operating costs based upon the electric utility's out-of-pocket operating costs.

The fuel price and economic activity forecasts that form the primary drivers of these models were not changed from one scenario to another to maintain consistency in the analyses. The other major model driver, the price of electricity, varies according to the results of the scenario. Therefore, any changes in customer demand from one scenario to another result entirely from the emissions reduction requirements.

Using an initial set of electricity prices for each utility, a forecast of customer demands is developed. These demands are then sent through a generation dispatch model to determine the operating costs associated with meeting the demands. The operating costs and demands are sent to a utility finance and rates model that determines a new set of electricity prices for each utility. These new prices are sent to the energy and demand model and a new iteration begins. The process is repeated until an equilibrium state is reached where prices and demands do not vary from one iteration to the next for each year of the analyses. Thus, the model includes a feedback mechanism that equilibrates energy and demand simultaneously with electric rates (Figure 1).

Figure 1. Cost-Price-Demand Feedback Loop



While the SUFG modeling system captures the impact of electricity price increases at the microeconomic level (i.e., a firm or individual's decision to use an alternate source of energy or a more efficient process), it does not capture the impact of price increases at the macroeconomic level (i.e., the effect on the state's economic development as firms decide where to locate new facilities). All scenarios included in this report were developed from the same set of macroeconomic assumptions.

In the later years of the analyses, new resources are needed for the utilities to adequately meet the load. This is accomplished through another iterative process with the costs associated with acquiring these resources (either through purchases, construction or conservation) impacting the rates accordingly. Since the demand levels in each scenario differ due to the price impacts, the amount of required resources changes also. However, the criteria for determining resource requirements are held constant to ensure consistency between scenarios.

Emissions control technologies will affect the price of electricity in several ways. In this modeling system, the capital cost of equipment is captured in the rates and finance model, using a traditional regulated rate of return. The operating cost impacts are captured in the generation dispatch model. These impacts include changes in fuel costs resulting from changes in overall plant efficiency, increased maintenance costs, and changes to generation unit availability, for both emissions reduction equipment installation and maintenance.

4. Emissions Control Scenarios

Previously, SUFG analyzed two different scenarios for complying with CAIR emissions reductions: one developed by the Indiana Department of Environmental Management (IDEM) and one from the Indiana Utility Group (IUG) [6]. The scenarios used different combinations of compliance options (new equipment, fuel switching, allowance trading, and generating unit retirement). Options varied between the scenarios in terms of capital cost, operating cost, and the year implemented. Table 2 lists the amount of capacity affected and the installation costs for both CAIR scenarios.

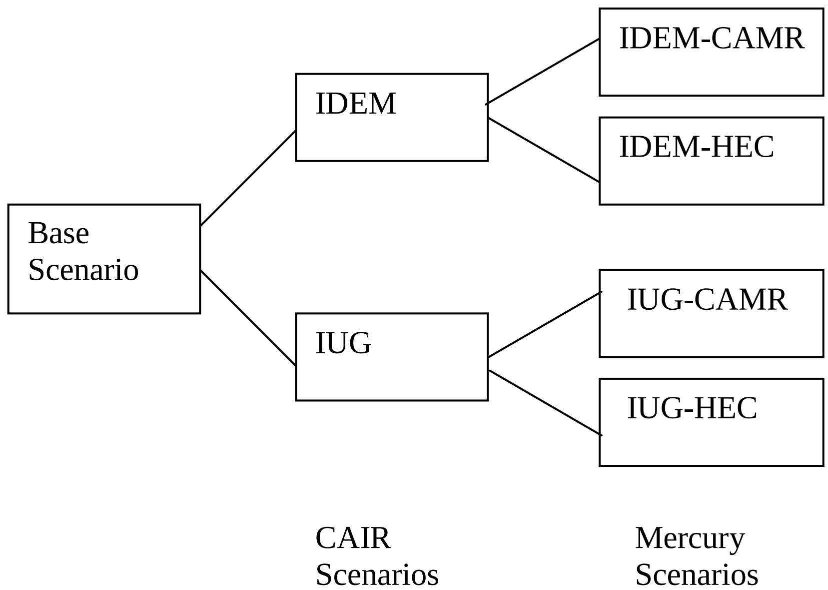
Scenario	Capacity Affected (MW)			Installation Costs (million 2005$)
	SNCR	SCR	FGD	
IDEM	180	2611	4686	1617
IUG	0	2508	3698	1976

Table 2. Capacity Affected and Installation Costs for CAIR Analysis

The four scenarios analyzed in this report begin under the assumptions developed for the CAIR analysis. Thus, the IDEM-CAMR scenario models the impact of the restrictions established by CAMR, under the compliance options and cost assumptions provided by IDEM. Similarly, the IDEM-HEC scenario models the impact of the restrictions proposed by HEC, under the compliance options and cost assumptions provided by IDEM. These scenarios are consistent with the assumptions used in the IDEM scenario for the CAIR analysis. Similarly, the IUG-CAMR (IUG compliance assumptions for

CAMR restrictions) and IUG-HEC (IUG compliance assumptions for HEC restrictions) are consistent with the assumptions used in the IUG scenario for the CAIR analysis. Figure 2 shows the relationship between the different scenarios that were used for this analysis. The scenario descriptions are also provided as an appendix to this report.

Figure 2. Relationships between Scenarios



The capacity affected and installation costs for the four scenarios are listed in Table 3. The SCR installations are incremental to those installed for the IDEM scenario in the CAIR analysis.

Scenario	Capacity Affected (MW)			Installation Costs (million 2005$)
	SCR	ACI	ACI+FF	
IDEM-CAMR	1499	0	0	159
IDEM-HEC	0	1015	6675	508
IUG-CAMR	0	0	3012	168
IUG-HEC	0	0	15069	1008

Table 3. Incremental Capacity Affected and Installation Costs for Mercury Analysis

In addition to the scenario assumptions, SUFG made further assumptions in order to perform this analysis using SUFG's traditional (or regulated) modeling structure. These assumptions pertain to future capital costs for retrofit control equipment, expenditure streams for retrofit equipment installation, and the timing of retrofit installations. SUFG feels these assumptions are reasonable, but also recognizes that they should be subject to further refinement in subsequent analyses, as further information becomes available.

SUFG has assumed that capital costs for emissions control equipment will escalate at an annual rate of 2.5% per year from the 2005 dollar base year estimates provided by IDEM and IUG. While this escalation rate assumption is open to debate, it is consistent with the assumptions SUFG employed in preparing the 2005 SUFG report *Indiana Electricity Projections: The 2005 Forecast*, which is used as a base case in estimation of the additional costs to ratepayers of further emissions reductions.

SUFG has assumed that control equipment for all affected generation units will be installed over an 18-month period for all retrofit options. SUFG has further assumed that the stream of expenditures for such retrofit is evenly divided across this 18-month period. Since the SUFG model is an annual model, SUFG has allocated the control retrofit costs to specific years based upon the assumed on-line date of the control equipment. Capital costs are escalated from the 2003 dollar base year to the middle of the 18-month construction period and then allocated to specific years. For example, if a control device is assumed to be on-line in the spring of 2009, capital costs are escalated from 2003 dollars to mid-year 2008 dollars and then allocated to 2007 expenditures (1/6 of the total), 2008 (2/3 of the total), and 2009 expenditures (1/6 of the total). The same procedure is used for fall installations, with capital escalation through the beginning of the on-line year and capital cost allocations of 50 percent (prior year) and 50 percent (on-line year). Fixed operations and maintenance costs are assumed to be incurred immediately following the installation of a control device even if the control is installed prior to the compliance requirement date.

The 18-month installation period used in these analyses does not represent the total time needed for planning, design and engineering. These processes take a considerable amount of time before the actual physical construction begins. Likewise, the 18-month time period does not represent the time that the generating unit must be taken out of service for the installation process. Any additional required downtime for mercury control device installation was not modeled for this analysis.

Since detailed installation schedules for emissions control devices were unavailable, SUFG assigned on-line dates for all retrofit controls in accordance with the installation time frame indicated in the individual compliance strategies. The procedure used to assign on-line dates is somewhat arbitrary and should be refined in future analysis. SUFG assigned on-line dates by attempting to minimize the capacity off-line for retrofits and delaying retrofits until required for compliance on an individual utility basis. For example, if a utility is required to retrofit two large coal units, the units were assigned retrofit periods of Fall and Spring; three large units were assigned retrofit periods of Spring, Fall, and Spring and so forth. A more reasonable allocation of retrofit dates would explicitly incorporate the utilities' maintenance schedules and attempt to overlay final installation with major maintenance periods as well as attempt to coordinate installation outages across utilities where possible.

While these analyses capture the price effects of retrofit outages, they do not address the question of whether the reliability of the system will be impaired. In 2001, SUFG conducted a study for the NO_x retrofits associated with the National Ambient Air Quality

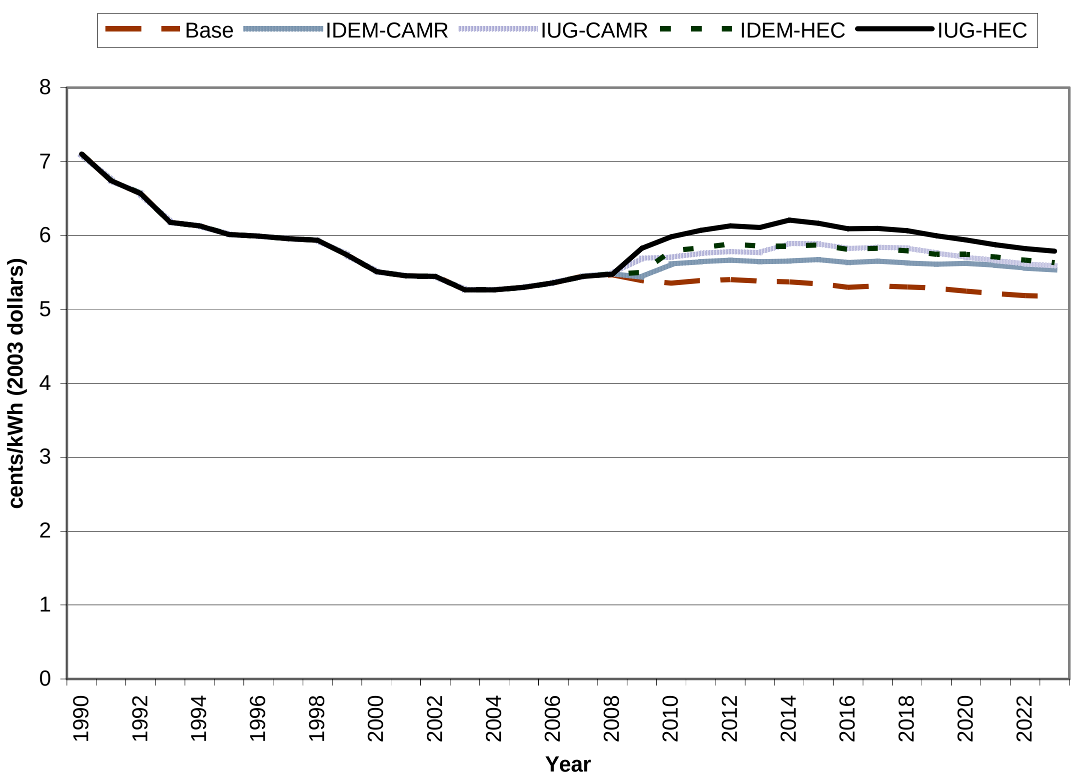
Standards, in which it was determined that the state would likely have sufficient capacity to handle the necessary retrofits [7]. It is uncertain whether that conclusion would be reached for the retrofits under the HEC proposed regulations, which take effect in 2010. If all retrofits were not completed by 2010 under these regulations, additional costs could be incurred as replacement power from more expensive sources may be needed. Since the first retrofits for the CAMR regulations do not take place until 2015, sufficient lead time should be available for utilities to complete the retrofits without compromising system reliability.

5. Results

Comparison of Rates to the SUFG Base Case

SUFG's projections of future electricity rates for the four mercury emissions control scenarios are compared with the base case from SUFG's 2005 report *Indiana Electricity Projections: The 2005 Forecast* in Figure 2. The base case was constructed assuming no emissions controls from either CAIR or mercury restrictions, so the scenarios represent cumulative changes to the base case. The rate projections in Figure 2 are an energy-weighted average for the residential, commercial, and industrial sectors for the five Indiana investor-owned utilities.

Figure 2. Electricity Rates by Scenario



The figure illustrates that average retail rates would be expected to increase 5 to 10 percent above the rates in the base scenario under the CAMR regulations, depending on the time period and scenario. The corresponding increase under the HEC proposal ranges from 10 to 16 percent. The rate projections for individual utilities vary from the state average, as some utilities will have a greater amount of capacity affected than others.

The effect on the individual rate classes is similar to the average but differs somewhat due to cost-of-service allocation of capital recovery and fixed operating costs. The differences across customer classes for the lowest and highest cost scenarios (IDEM-CAMR and IUG-HEC, respectively) for representative years are presented in Tables 4 through 6. Rates are provided in 2003 dollars in order to be consistent with the base scenario from SUFG's 2005 forecast.

	Base Scenario (¢/kWh)	IDEM-CAMR Scenario		IUG-HEC Scenario	
		Rate (¢/kWh)	Change	Rate (¢/kWh)	Change
Residential	6.79	7.09	+4.40 %	7.51	+10.62 %
Commercial	5.83	6.09	+4.44 %	6.45	+10.72 %
Industrial	4.10	4.33	+5.57 %	4.63	+12.87 %
Average	5.35	5.62	+4.91 %	5.98	+11.76 %

Table 4. Rate Comparisons by Sector in 2010 (in 2003 dollars)

	Base Scenario (¢/kWh)	IDEM-CAMR Scenario		IUG-HEC Scenario	
		Rate (¢/kWh)	Change	Rate (¢/kWh)	Change
Residential	6.62	7.00	+5.78 %	7.56	+14.30 %
Commercial	5.74	6.06	+5.66 %	6.57	+14.44 %
Industrial	4.23	4.50	+6.30 %	4.87	+15.21 %
Average	5.35	5.68	+6.17 %	6.17	+15.36 %

Table 5. Rate Comparisons by Sector in 2015 (in 2003 dollars)

	Base Scenario (¢/kWh)	IDEM-CAMR Scenario		IUG-HEC Scenario	
		Rate (¢/kWh)	Change	Rate (¢/kWh)	Change
Residential	6.34	6.78	+7.06 %	7.14	+12.65 %
Commercial	5.56	5.93	+6.65 %	6.25	+12.49 %
Industrial	4.29	4.60	+7.05 %	4.84	+12.71 %
Average	5.25	5.62	+7.18 %	5.94	+13.18 %

Table 6. Rate Comparisons by Sector in 2020 (in 2003 dollars)

The rate increase in ¢/kWh tends to be slightly higher in the residential sector and slightly lower in the industrial sector, with the commercial sector close to the average. In terms of a percentage increase, the industrial sector sees a higher increase due to the lower initial rates. These tendencies also hold for the two scenarios not listed in Tables 4 through 6 (IUG-CAMR and IDEM-HEC).

Comparison of Rates to the CAIR Scenarios

In order to estimate the incremental cost of mercury restrictions, it is necessary to compare the four mercury control scenarios to the two CAIR scenarios upon which they were developed. Table 7 shows the comparison between the IDEM scenario and the IDEM-CAMR and IDEM-HEC scenarios for selected years. Similarly, Table 8 provides the comparison between the IUG scenario and the IUG-CAMR and IUG-HEC scenarios.

	IDEM Scenario (¢/kWh)	IDEM-CAMR Scenario		IDEM-HEC Scenario	
		Rate (¢/kWh)	Change	Rate (¢/kWh)	Change
2010	5.63	5.62	-0.24 %	5.79	+2.80 %
2015	5.67	5.68	+0.19 %	5.87	+3.61 %
2020	5.58	5.62	+0.79 %	5.74	+2.95 %

Table 7. Rate Comparisons for IDEM-based Scenarios (in 2003 dollars)

	IUG Scenario (¢/kWh)	IUG-CAMR Scenario		IUG-HEC Scenario	
		Rate (¢/kWh)	Change	Rate (¢/kWh)	Change
2010	5.70	5.71	+0.14 %	5.98	+5.00 %
2015	5.80	5.89	+1.47 %	6.17	+6.28 %
2020	5.65	5.71	+1.06 %	5.94	+5.16 %

Table 8. Rate Comparisons for IUG-based Scenarios (in 2003 dollars)

Under EPA's CAMR the first phase of mercury emissions reductions are achieved from co-benefits associated with SO_2 and NO_x reductions from CAIR. Therefore, there is little change early in the forecast period for the two scenarios based upon the CAMR restrictions, since there are no new incremental pollution control devices installed. The cost of installing mercury monitoring equipment tends to be offset by revenue from the sale of mercury emissions permits. Furthermore, the convergence tolerance of SUFG's modeling system is 0.25 percent, so the changes due to CAMR in 2010 should not be considered to be significant.

Comparison between the CAMR and HEC Restrictions

The mercury restrictions proposed by the Hoosier Environmental Council are significantly different than those promulgated by EPA under CAMR. Thus, a comparison of prices under both sets of restrictions is warranted. Table 9 shows the comparison for both IDEM-based mercury control scenarios for selected years and Table 10 shows the comparison for the IUG-based mercury scenarios.

	IDEM-CAMR Scenario Rate (¢/kWh)	IDEM-HEC Scenario Rate (¢/kWh)	Change
2010	5.62	5.79	+3.05 %
2015	5.68	5.87	+3.41 %
2020	5.62	5.74	+2.14 %

Table 9. CAMR vs. HEC Restrictions for IDEM-based Scenarios (in 2003 dollars)

	IUG-CAMR Scenario Rate (¢/kWh)	IUG-HEC Scenario Rate (¢/kWh)	Change
2010	5.71	5.98	+4.85 %
2015	5.89	6.17	+4.74 %
2020	5.71	5.94	+4.05 %

Table 10. CAMR vs. HEC Restrictions for IUG-based Scenarios (in 2003 dollars)

Thus, it appears that the greater restrictions associated with the HEC proposal results in electric rates between 2 and 5 percent higher than those seen under CAMR, depending on the assumptions regarding the amount, type, and cost of the control equipment needed.

6. Summary and Conclusions

This paper presented the projected impacts of mercury emissions reductions on Indiana electricity prices. Scenario analyses were performed using the SUFG traditional regulation modeling system. These scenarios depict various combinations of control technologies, such as selective catalytic reduction systems, activated charcoal injection systems, and fabric filters. The scenarios also incorporate two different sets of mercury emissions reductions regulations: EPA's Clean Air Mercury Rule and an alternative rule proposed by the Hoosier Environmental Council.

The results of these scenarios indicate a wide possible variation in electricity price increases due to mercury emissions reductions. Under the IDEM scenario, prices are expected to increase by up to 1 percent (above the previously analyzed impact of the Clean Air Interstate Rule) due to the emissions controls required by CAMR. This represents a cumulative 5 to 7 percent increase above the 2005 SUFG base forecast. In the IUG scenario under the HEC proposal, prices are expected to increase by roughly 5 to 6 percent above prices under CAIR and as much as 15 percent over the 2005 SUFG base forecast. This variation is largely a function of the different assumptions regarding the emissions controls needed and their costs, as well as the fundamental differences in the level of reductions required under CAMR and the HEC proposal.

Finally, the increase in electricity rates resulting from mercury emissions reductions is felt by all three customer classes, with the increase to residential rates being slightly greater (and the increase to industrial rates being slightly lower) than the increase to commercial rates.

Acknowledgements

The State Utility Forecasting Group would like to acknowledge the Indiana Department of Environmental Management and the Indiana Utilities Group for their input to this project. SUFG would also like to acknowledge the support of the Indiana Utility Regulatory Commission. The results of the work and any conclusions drawn from them are entirely the responsibility of SUFG. The assistance provided by IDEM, IUG, and IURC should not be construed as an endorsement of this work.

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Appendix

Scenario	Description
Base	SUFG 2005 Forecast base case; does not include costs associated with CAIR or either CAMR or HEC mercury restrictions
IDEM	Includes IDEM's assumptions for meeting CAIR, but does not include costs associated with either CAMR or HEC mercury restrictions
IDEM-CAMR	Includes IDEM's assumptions for meeting CAIR and CAMR
IDEM-HEC	Includes IDEM's assumptions for meeting CAIR and HEC mercury restrictions
IUG	Includes IUG's assumptions for meeting CAIR, but does not include costs associated with either CAMR or HEC mercury restrictions
IUG-CAMR	Includes IUG's assumptions for meeting CAIR and CAMR
IUG-HEC	Includes IUG's assumptions for meeting CAIR and HEC mercury restrictions