BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	R06-25
PROPOSED NEW 35 ILL. ADM. CODE 225	)	(Rulemaking – Air)
CONTROL OF EMISSIONS FROM	)	
LARGE COMBUSTION SOURCES(MERCURY)	)	

TESTIMONY OF EZRA D. HAUSMAN, Ph.D.

Qualifications

My name is Ezra D. Hausman, Ph.D. I am a Senior Associate with Synapse Energy Economics, Inc. ("Synapse"), a research and consulting firm specializing in energy and environmental issues. Synapse's areas of expertise include electricity market analysis; generation, transmission and distribution system reliability; market power analysis; electricity market price forecasting; valuation of stranded costs and benefits; and integration of energy efficiency and renewable energy in wholesale electricity and capacity markets.

I have been employed by Synapse since July of 2005. Prior to this I was employed as a Senior Associate with Tabors Caramanis & Associates (TCA) since 1997, performing a wide range of electricity market and economic analyses and price forecast modeling studies, including asset valuation studies, market transition cost/benefit studies, market power analyses, and litigation support studies. I have extensive personal experience with market simulation software including GE-MAPS, and I have strong familiarity with a number of other market simulation environments and approaches to electricity market, and economic analysis.

I hold a B.A. from Wesleyan University, a M.S. in civil engineering from Tufts University, an S.M. in applied physics from Harvard University and a Ph.D. in atmospheric chemistry from Harvard University.

Purpose and Summary of Testimony

I was asked to testify today by the Illinois Environmental Protection Agency (Illinois EPA) in order to offer my expert analysis of how the proposed Mercury emissions rule in

Illinois will impact the Illinois electricity market and the Illinois economy. Much of my analysis is based upon information contained in the Technical Support Document (TSD) provided by the Illinois EPA in support of the rule. I have also relied upon data provided by ICF Corporation relating to their use of the IPM model to analyze the impacts of this rule. While I do rely upon the same underlying data used by ICF, in many cases, my analysis differs from the conclusions reached by ICF using this model. I will explain these differences, and why I feel my analysis to be more realistic, as appropriate throughout my testimony.

I begin with my analysis of the TSD's conclusions regarding the proposed rule's expected impact on wholesale and retail electricity prices, and on the competitiveness of Illinois generating units. I will address the question of whether existing coal-fired generating plants would be likely to “retire” as a result of the proposed rule, and whether this would cause reliability concerns in the state of Illinois. Finally, I will offer some analysis of the economic impact of the proposed rule on the economy and employment in the State of Illinois, as well as health-related impacts. My conclusions may be summarized as follows:

- The cost of producing electricity at Illinois coal plants is likely to increase by about 0.0375 cents/kwH;
- The impact on retail prices is likely to be much smaller than the impact on production cost because coal units in Illinois only set the price of electricity for a fraction of the hours of any year. I calculate that the *total* price impact of the rule for Illinois ratepayers will be between zero and $11 million per year, in 2006 dollars;
- I calculate that the *total* price impact on consumers in the broader region (Illinois and the surrounding states) will be up to $60 million annually, which is roughly twice the total annual cost of compliance for Illinois generators;
- In terms of reliability impacts due to retirements of plants that would be rendered uneconomic by the rule, I conclude that a very small number of plants are likely to retire, if any, and that the impact on system reliability is negligible;
- In terms of economic impacts, I find that any direct job losses due to the proposed rule are likely to be more than offset by economic benefits, including construction, installation and operational employment increases, and new jobs in the tourism and recreational fishing industries;

- The health and avoided premature death benefits of reducing mercury emissions under the rule will be hundreds of millions of dollars per year, well in excess of the cost of implementing the rule.

Impact of Proposed Rule on wholesale and retail electricity prices

I first address the TSD's analysis and conclusions regarding the proposed rule's expected impact on wholesale and retail electricity prices and on the competitiveness of Illinois generating units, relating especially to the material on that point contained in Chapter 9 of the TSD. This section of my testimony supports the following conclusions:

1. The analysis of electricity markets summarized in Chapter 9 of the TSD overstates the effects of the proposed rule on electricity market prices and costs to Illinois electricity consumers.
2. The retail electricity cost impact for Illinois is likely to fall somewhere between zero and $11 million per year.
3. The effect of the proposed rule on the competitiveness of coal-fired generating units in Illinois is likely to be quite modest, smaller than the effects of other factors.

Electric Power System Modeling

The operation and evolution of electric power systems are complex processes subject to a wide variety of technical, economic, and regulatory factors. Computer models are used to understand these processes, and to estimate the impacts of changes to the system upon the characteristics and costs of the system; one such change would be a proposed environmental regulation such as the proposed mercury rule. When analyzing such a change, it is useful to consider the short-term and the long-term separately, since the roles of various factors and the uncertainty associated with market simulations differ for the two situations.

In the short-term, the set of capacity resources is largely fixed and impact analyses can focus upon the *operation* of the system. System operations are complex but relatively well understood and subject to rules and procedures that are implemented by grid operators such as PJM and MISO[1]. Regional wholesale power markets are dispatched

[1] The PJM Interconnection (“PJM”) and the Midwest Independent Transmission System Operator (“MISO”) are centrally-dispatched Regional Transmission Organizations (RTOs) which control large

based upon bids submitted by generators in order to minimize the total costs, subject to various physical constraints such as transmission limitations and generator ramp rates.

Dispatch models such as MAPS and MARKETSYM simulate the dispatch using very detailed inputs on the available resources, their costs and heat rates, their locations relative to transmission constraints, and chronological electricity demand by customers, typically on an hourly basis. The inputs that matter to operations analysis are mainly "variable costs" which include fuel and some O&M costs including the variable costs of pollution controls. The outcome of these models depends directly upon the input data, so any uncertainty in forecasting future conditions, of which there is a great deal, results in implicit uncertainty in the forecast. Nonetheless, the algorithms are generally accepted to be good for representing the phenomena that they attempt to simulate – the deterministic operation of the electric power system given a certain set of input assumptions.

In the long-term, say five years or more, the set of capacity resources can be changed by capital investment decisions. In this case impact analysis must address the *capacity mix* of the system as it evolves over a period of years, with power plant additions and retirements as well as capital investment in the generating plants, including investments in air emissions controls. Capital investment and plant retirement decisions are quite complex and notoriously difficult to represent in a computer model. In the simplest sense, they depend upon reasonably well understood fundamentals such as discounted cash flow analysis. For example, a unit retirement decision would, at its simplest, be a straightforward matter of projecting forward-going costs (e.g., for fuel, O&M, and required investments for continued operation) and expected revenue (e.g., for selling capacity, energy, and any ancillary services into the market), and applying a discount rate to compute the present value of the net revenues. However, these decisions also depend upon a number of highly complex factors and considerations such as:

- Selection of the discount rate to use in the present value calculation in any particular situation;

regions of the eastern United States electricity market. Illinois is split between these two, with the northern area (including Chicago) controlled by PJM, while the southern part of the state is controlled by MISO.

- Consideration of strategic factors such as market power;
- Consideration of uncertainty, risk, and option value, which are generally not represented in market simulation models;
- Regulatory constraints and risks.

Attempts have been made to incorporate some of these into computer models, but this is quite challenging, and the accuracy of such models will be relatively poor. The results depend upon the input data assumptions as well as algorithms to represent complex corporate investment behavior, which at times can turn on little more than a decision-maker's hunch about the future. The assumptions and algorithms may or may not be realistic in any particular situation.

In this case, the Integrated Planning Model (IPM) was used to estimate the electric market effects that are reported in Chapter 9 of the TSD. The IPM model has previously been applied by the U.S. EPA for environmental policy impact analysis, including analysis of the impact of the Clean Air Mercury Rule on a nationwide basis. The model, developed by ICF Consulting, attempts to represent both system operations and capital investment decisions over a multi-year planning horizon; in tackling both complex problems at once, of necessity it does both in a highly simplified manner.

IPM is a linear programming model that develops a single scenario for system capacity additions and retirements by finding the set of decisions that minimizes the present value total costs to operate the entire electric power system over a specified period, subject to various constraints. For example, demand must be met in each region for each time period, and capacity requirements must be satisfied. Limitations on air emissions must be observed, transmission limits on key interfaces must be respected, and so on. IPM is a deterministic model that works with perfect foresight, by which I mean that it makes its internal choices about operations and investment as if decision-makers knew (or believed) that the modeler's input assumptions about future load conditions and technology costs were guaranteed to be perfectly accurate. It calculates some costs endogenously, such as fuel costs and emissions allowance prices, based on input assumptions about emission caps and well-head and minemouth prices, plus its internally calculated demand for those items. However, both the deterministic inputs and the algorithms used to calculate prices involve some amount of uncertainty that is not publicly estimated by IPM, but which must be assumed to exist by anyone using these results.

In order to accommodate the large geographic scope and the ambitious incorporation of capital investment decisions into the model, IPM used aggregated and simplified data in its unit dispatch function. For example, IPM represents system load conditions using a very limited number of "segments" (i.e., a year of customer loads is represented by six load segments in each of two seasons.) Generating units are not dispatched chronologically as they are in a real market; rather, the generators are dispatched to meet each of these load segments as part of the single, all-encompassing optimization problem, and the resulting unit operation is extrapolated and interpreted to represent annual operations. IPM simulates generating unit forced outages as capacity deratings. That is, rather than simulate actual random outages of generating units during dispatch, the model reduces the capacity of each generating unit to approximate the effect of forced outages. IPM predicts plant additions and retirements such that total present value system cost in the model, over the entire planning period, is minimized, but selects additions only from among a list of potential resource additions with specified cost and operational characteristics. All of these simplifications should be kept in mind when interpreting the results of one or more IPM model runs.

The nature and extent of the simplifying assumptions suggest that the dispatch representation in the model is quite coarse-grained. For capital investment and retirement decisions, the model has some problematic differences with the way that such decisions are actually made; for example, IPM allows fractions of units to be built or retired in order to reach an "optimal" result, and does not take uncertainty about the future into account. The model results show a considerable degree of lumpiness, as is inevitable in a model that represents hourly dispatch in such a highly aggregated fashion. This may not be a problem in some cases where the policy being analyzed in much larger in scope or impact, such as a national CAMR analysis, for which one could argue that the errors tend to cancel each other out. However, when trying to discern impacts on the scale of a single state, this lumpiness can obscure the information one seeks to obtain from the model. In sum, my judgment is that IPM is ill-suited for analysis of a rule in a limited geographic area (e.g., Illinois), affecting a small number of generating units (e.g., the existing coal-fired units in Illinois), with a relatively small compliance cost (e.g., estimated at $33 million per year in Table 8.7 of the TSD). The model results in this case bear out this judgment.

My concern about the coarse resolution of the model is particularly acute in this case because the result of interest is the *difference* between two model runs, one with and one without the Illinois rule. If the inaccuracy in an individual model run is, say, plus or minus 5 percent for the output variable of interest (e.g., the market price in a particular location) that might be perfectly acceptable for some purposes. But for understanding the difference between two such model runs where the policy is a relatively small effect (e.g., less than 1 percent) then it is impossible to get a meaningful result by comparing two individual runs each with 5% uncertainty. The “noise” simply overwhelms the “signal”.

In a national scenario, IPM is simulating a system of more than 10,000 generating units in 48 states, representing a total electricity industry with a total capacity of about 950,000 MW and annual plant expenditures of about $90 *billion*. In contrast, the Illinois rule which it is attempting to analyze, will effect 25 coal-fired generating units and will have a compliance cost of about $33 *million* on an annualized basis. This level of precision is simply far too much to ask from such a coarse-grained and large scale modeling exercise.

Impacts of the Proposed Rule on Costs and Electricity Market Price

The application of the Illinois mercury control rule will reduce the mercury emissions from Illinois coal plants, but will also add to the costs of those plants and to the variable cost of their generated electricity. A detailed analysis of the mercury control costs on a unit by unit basis is contained in Chapter 8 of the TSD. The analysis supporting these findings was carried out by Dr. James Staudt of Andover Technology Partners. The starting point for our cost impact analysis is summarized in Table 8.7 of that report and presented below, in a slightly different format.

Mercury Control Costs for Illinois Coal Plants

In thousands of 2006 $

	CAMR 2010	Illinois Rule	Difference
Capital Investment	$35,515	$75,593	$40,078
Annual costs:			
Sorbent Cost	$18,665	$41,729	$23,064
Toxecon O&M	$0	$425	$425
Ash Disposal	$9,900	$13,403	$3,503
Annualized Capital Cost*	$4,972	$10,583	$5,611
Total Annual Cost	$33,537	$66,140	$32,603

*Assumes 14% capital recovery factor

The yearly additional control costs associated with the Illinois rule are $33 million, of which most of the cost is for sorbent. This is the cost borne by the generating unit owners to retrofit and operate their units with mercury emissions controls; it does not translate directly into electricity prices and costs to consumers.

The historic generation from the Illinois coal plants, from TSD Chapter 8, is 86,997 GWh. That converts into an average cost increase for the Illinois coal plants of $0.375/MWh. For comparison, current retail prices in Illinois are about $70.00/MWh and are likely to increase if price caps are removed as proposed.

In order to determine how this increase in coal plant costs will affect electricity market prices, it is necessary to estimate the amount of time that the coal units bearing these extra costs are "on the margin" and therefore influencing the market price for electricity in the regional dispatch. That, in turn, depends upon regional operation of the electricity grid and the dynamics of new entry to the electricity market. I believe that a reasonable range for the annual electricity wholesale market cost to Illinois customers is between zero and $11 million.

I calculate the upper end of this range as follows.

1. I estimate that coal generation is "on the margin" in the regional dispatch 85% of the time.[2]

2. The Illinois electricity market is a tightly interconnected part of a much broader wholesale electricity market. For current purposes I will conservatively assume that this market includes Illinois, Indiana, Wisconsin, Iowa, Missouri, and Michigan, of which Illinois contains about 20% of the regional coal generation.[3]

3. I multiply the $0.375/MWh cost increase from the rule for Illinois coal by 0.85 and 0.20 to reflect the contribution of Illinois coal units to the regional electricity market price, yielding a wholesale electricity market price impact of $0.064/MWh.

4. At annual electricity sales of about 166,000 GWh,[4] the wholesale cost impact to Illinois electricity customers amounts to $11 million. I assume that this increase is passed directly through to the retail cost impact.

I believe this is a conservatively high estimate of the price impact of the rule on Illinois electricity consumers, for the following reasons.

First, my calculations include the variable costs (sorbent and ash disposal) and fixed costs (annualized investment) of compliance with the rule. A dispatch model simulation would only apply the increased variable costs to calculate the energy price effects, since the fixed costs would generally not be included in the generators' energy supply offers.

Second, the compliance scenario introduced in the TSD is a very simple one, and there may be ways that the market could respond to the rule that would achieve compliance at a lower cost. These might include increasing electricity imports (or decreasing electricity exports), retiring inefficient generators, and installing other emission control technologies (e.g., FGD and SCR, where Hg reductions would be a co-benefit). To the extent that

[2] Based upon the PJM Market Monitoring Unit's "2005 State of the Market Report," March 8, 2006 (which indicates on page 86 that coal was on the margin 62% of the time in PJM in 2005); MISO's "March Monthly Report: April 20, 2006" (which indicates on page 77 that coal was on the margin about 86% of the time in MISO in that month); and inspection of the capacity supply curve compared with load levels.

[3] A broader region would probably be more appropriate for wholesale market price calculations, given the strong transmission interconnections in the MAIN and ECAR reliability regions. Ideally, multi-area electricity market simulation model analysis would be used to determine the impact of an electricity market price increase upon the regional market, and the extent to which the price increases occur in different portions of the Eastern Interconnection. However, given the lack of transmission constraints inhibiting the *import* of electricity to Illinois, we believe that the six-state region is a reasonably conservative proxy.

[4] According to EIA data, retail electricity sales in Illinois were 139,254 GWh in 2004 and 144,554 GWh in 2005. Extrapolating this growth rate (3.8% annual) to 2009 yields 166,000 GWh.

some of these approaches were found to be lower cost and to contribute to a mixed compliance approach, the overall total cost would tend to be reduced. There is no indication that Dr. Staudt attempted to find the *least cost* compliance scenario, nor was it his task to do so.

Third, and most importantly, is the impact of new market entry in response to anticipated electricity market price increases. In regional electricity markets, the long-term price of electricity is generally expected to be equal to the levelized annual cost of building and operating a new power plant. While there will be excursions above and below this “equilibrium price” set by market entry, there are strong forces working to bring prices into line. If market prices fall below the cost of entry, then developers will defer and cancel generating facility construction projects. If market prices exceed the cost of entry for a prolonged period, then developers will initiate and accelerate capacity construction projects, in order to earn the high profits available under such conditions.

This dynamic of market entry disciplining price increases that would otherwise occur is one reason that I put the low end of potential market price effect at zero. The other reason is that, with excess generating capacity in the region and no relevant and binding limits on power imports (or decreased exports), it may be that existing generators simply cannot increase market prices in order to pass along compliance costs to customers.

The modest impact of the proposed rule on electricity prices can also be seen in the “supply curves” provided here as Exhibits EDH-1 and EDH-2. These were derived from the IPM model files provided by ICF. The graph in Exhibit EDH-1 shows the cost of electricity from Illinois generators only, with and without the proposed rule. The line for the case with the rule shows a slight cost increase relative to the case without the rule, in the middle range of the supply curve—this represents the increased production cost for specific coal units under the proposed rule relative to CAMR. At some load levels, the cost of electricity is actually *lower* with the proposed rule in place, according to the IPM model results. This would occur if certain plants opted to invest in emission control technology as a result of the rule and thereby eliminated the need to purchase allowances for NO_x and SO_2 emissions. The associated capital investment is not a variable cost of production, so it is not reflected in the figure. The graph in Exhibit EDH-2 is an analogous supply curve but for the multi-state region, including Illinois, Indiana, Wisconsin, Iowa, Missouri, and Michigan. Here the effect of the Illinois rule is considerably more subtle, reflecting the fact that the marginal cost of electricity at just about any regional load level would be largely unaffected by the rule. If the curve in Exhibit EDH-2 represents the highly competitive generation mix that serves a large interconnected market including Illinois, then the only time prices can be affected by this rule is when the load falls in the area where these two curves diverge. Even in those cases, the price impact of the rule can be no more than the vertical distance between the lines in that region.

There are large differences in production cost between coal units and the lower-operating-cost nuclear units, and also between coal units and the high-operating-cost oil and gas units. There are, in fact, some substantial differences in production cost among the coal-fired units, which inhabit the range between about $16/MWh and $23/MWh in production cost as shown on the vertical axis. These differences among the coal units have to do with variations in age, size, efficiency, fuel supply and other factors. The cost implications of compliance with the Illinois rule, 37.5 cents per MWh, are quite small in the overall context of variation among generating unit costs of production, and thus the effect on the supply curve for energy is, as shown in the Exhibits, quite small.

Impacts of the Proposed Rule on Generators

The cost impacts are of importance from the perspective of Illinois electricity customers, and they will be of use in estimating the direct impact on the Illinois economy later in this testimony. For generators, the range of impacts differs, but the likely impacts are also quite modest on a net basis.

Consider first the scenario in which market prices are not increased as a result of the rule. In that case, Illinois generators would bear the full compliance cost impact of $33 million per year. While not a trival sum, in the context of the overall electricity markets it is almost negligible. To put it in context, the total cost of fuel to electric power plants located in Illinois amounts to about $2 billion per year.[5]

It is also interesting to consider a scenario in which electricity market prices do increase as a result of the proposed rule. I have proposed a high case in which regional market prices increase by $0.064/MWh. In this case, the total annual cost increase to customers in the multi-state region amounts to about $60 million annually. This is roughly twice the estimated annual compliance cost of $33 million, indicating that generators as a group will be better off financially with the rule than without it. Of course, in this scenario there are winners and losers within the group of generating companies, but on average the generation owners would be more than made whole.

IPM Results

The IPM model was discussed earlier in my testimony, where I highlighted how the coarse resolution of the model limit its utility for simulating a market effect as subtle as the one under consideration here. As may be seen in Chapter 9 of the TSD, the electricity price and cost results obtained using the IPM model are dramatically higher than those I have calculated. Specifically, ICF reported incremental price increases associated with the Illinois rule, relative to the CAIR/CAMR case, of $0.57/MWh, $1.67/MWh, and $1.15/MWh for the years 2009, 2015, and 2018, respectively.[6]

In terms of costs to Illinois electricity consumers, the same IPM runs put the totals for 2009, 2015, and 2018 at $99 million, $311 million, and $221 million.[7] For costs to

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[5] Source: IPM model reports.

[6] The prices reported in Exhibit A.3 on page 4 of “Analysis of the Proposed Illinois Mercury Rule, Appendix A: Summary Results Tables,” March 10, 2006, by ICF, are $0.50/MWh, $1.46/MWh, and $1.00/MWh for the three years. But these are reported in 1999 dollars. The “Price Indexes for the Gross Domestic Product” reported by the US Department of Commerce, Bureau of Economic Analysis, indicate an inflator of 14.6 percent from 1999 to 2005. I applied the 14.6 percent inflation factor to convert the prices from 1999 dollars to 2005 dollars.

[7] The costs reported in Exhibit A.5 on page 6 of “Analysis of the Proposed Illinois Mercury Rule, Appendix A: Summary Results Tables,” March 10, 2006, by ICF, are separately by customer class. I totaled the customer classes, and got $86 million, $271 million, and $193 million. But because these are in 1999 dollars I applied the 14.6 percent inflation factor to convert the costs from 1999 dollars to 2005 dollars.

"national" electricity consumers, the IPM runs put the totals for 2009, 2015,and 2018 at $332 million, $529 million, and $786 million.[8]

The IPM results imply that $33 million in annual production cost increases would translate into hundreds of millions of dollars of annual costs to consumers. Electricity markets may have their flaws, but the idea that they could be so inefficient and so punitive to customers, and that we reside on a precipice where a small increase in the cost of coal generation will tip us into the abyss, defies credulity. The implication of these results suggests a tremendous windfall to generators flowing from the Illinois rule. My judgment is that that this windfall will not occur, but rather that the impacted coal generators in Illinois may or may not recover the costs of compliance, that the net impact on these entities will be small.

There are various aspects of the way the Illinois rule is modeled in the IPM model that make the IPM impact results conservatively high, including the representation of the emission caps (maximum total emissions instead of maximum emission rates), decreased flexibility in compliance (relative to the Proposed Rule's actual provisions), and the accelerated compliance date (at the beginning of 2009 rather than at mid-year 2009). I review some of these in greater detail in the next section of my testimony. But while these aspects of the IPM modeling approach will tend to exaggerate the impact of the rule, it remains difficult to see how they could account for ICF's results in terms of market prices and customer costs. I can only conclude that the results are an artifact of the model structure, which is designed more for wide-ranging analysis of national policy than for highlighting the smaller-scale impacts of a regional rule.

One effect predicted by the IPM model with which I do concur is that energy exports from Illinois may be decreased as a result of this rule. Units with production costs just below the marginal cost of electricity in the absence of sorbent costs, for example, may be rendered uneconomic to run during certain hours given this small additional expense.

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[8] As with the Illinois costs to consumers, I totaled the customer classes (yielding $290 million, $462 million, and $686 million for the 3 years, respectively) and applied 14.6 inflation factor to convert to 2005 dollars.

However, in this case the revenue they would have earned during these hours would have just barely covered their running costs, so the impact of this output reduction on their overall economic performance will be minimal. Further, if other states adopt similar rules in the future, this effect will be abated.

Finally, I find that IPM is unrealistic in its treatment of power plant retirement decisions. This issue is discussed in the next section.

Electric System Reliability Impacts of the Proposed Rule

The IPM model runs performed in support of the Illinois rulemaking predict the retirement of a number of older, coal-fired generating units as a result of the proposed rule. My judgment is that this prediction is overstated, and that in any case that this level of potential retirements raises no reliability concerns. My reasons are as follows:

- The total MW capacity of retirements predicted by the IPM model runs as a result of this rule is quite modest, representing less than 1% of in-state capacity and a much smaller share of regional capacity. Even this is likely to be an overestimate, given differences between the model implementation and the realities of the marketplace;
- Illinois is strongly interconnected and shares capacity requirements with a large region that will be unaffected by this rule[9], making the total MW capacity of possible retirements comparatively even less significant;
- The reliability regions and market operators encompassing Illinois have rules in place to prevent retirements if the specified units are required for reliability reasons;
- If there are any subregions within Illinois that have capacity shortages, these subregions are likely to have higher electricity prices, meaning that units located in these areas will receive extra revenues and are less likely to retire;
- The units identified for retirement by the IPM model are small and relatively inefficient, and may well be nearing the end of their operating lives in any case; it is likely that they would be retired, upgraded or replaced with more efficient and cleaner technology with or without the proposed rule within the next several years;

[9] A number of other states in the region are considering similar state-specific mercury rules , but the current analysis is focused upon the effect of Illinois' proposed.

- The cost of new entry is only lightly impacted by the rule, so the rule will hasten, if anything, the development of new generating capacity in Illinois and the surrounding region.

Retirements likely to be minimal

The IPM forecast predicts 345 MW of coal plant retirements in Illinois by 2009 in the case including national CAIR/CAMR rule, and an additional 252 MW of coal plant retirements in Illinois by 2009 under the proposed, more stringent Illinois EPA mercury rule. For perspective, the model represents a total of 16,000 MW coal-fired capacity in Illinois and 43,000 MW of total in-state generating capacity. Thus the retirements represent 1.6% of in-state coal generation capacity and 0.6% of total in-state generating capacity.

I believe the IPM model over-predicts retirement in this case, and that the actual number is likely to be far smaller. There are a few reasons for this. One reason is that it is much easier to build and retire generating units in a model than it is in the real world. For example, the IPM model can and does predict "partial" retirements, which is to say that it finds an optimal number of units to retire which may include part of some unit even if that is physically impossible. My understanding is that the IPM model does not have the ability to "mothball" a unit (maintain it in a standby mode) instead of retiring it, which would otherwise allow it to be returned to service much more easily in the future should conditions render that profitable. Mothballing of generating units is quite common in real electricity markets. This is because the option of returning a unit to service in the future, should market conditions become favorable, is valued in a way that is difficult to capture in electricity market models with "perfect foresight".

Another reason that the model overstates likely retirement is that the gas prices calculated by the model are very low compared to today's gas and gas futures prices. Gas prices are calculated endogenously in the IPM model, presumably based on a formula that has been fit to historical gas price trends. Unfortunately, the current gas market prices are well above the historical norm for reasons that reflect the unprecedented growth in demand, increasingly costly domestic gas production, and the globalization of the gas market. ICF provided the gas prices to Synapse upon request, and they come out at about $4.25 per

MMBtu in 1999 dollars. This is perhaps half the cost of gas in today's market or less. As a result, the IPM model would seriously understate electricity prices and revenues coal units would receive when gas is on the margin. If more realistic gas prices were considered in the model, the economics of coal units would look quite a bit more attractive.

Finally, the implementation of the Illinois rule in the IPM model is unrealistically stringent. The rule as proposed allows some flexibility in meeting the requirement, including some averaging of emissions among plants under certain conditions. In the model implementation a hard cap is in place for each plant. Clearly, generation owners who are able to reallocate their emissions among plants will find more economical ways of controlling emissions than they would were they required to rigidly reduce emissions equally on all plants. Specifically, it would often make sense to leave uncontrolled those units that run infrequently, taking advantage of the ability to average overall emissions instead of investing in emissions controls that would be underutilized. While it is hard to draw solid conclusions on capacity factor due to the low resolution of the IPM model, the units that are slated for retirement are those with the lowest reported non-zero capacity factors of all coal units in Illinois. These units would be particularly subject to this particular distortion.

Thus I conclude that the 252 MW of coal retirements predicted by the IPM model are unlikely to occur, but even if they did the implications for reliability would be negligible.

Despite this judgment on my part, it is important to consider the implications in case this level of retirement did occur. I do not believe that this would present a problem in terms of reliability, because both the local and regional systems have considerable reserve capacity. The most recent projection of reserve capacity in the MAIN region,[10] for example, indicates that for the coming summer MAIN has a planning reserve of 17.6% without including "uncommitted resources". When uncommitted resources are

[10] The MAIN region has been superseded as of January 1, 2006, so that Illinois is now divided between the Reliability First and SERC reliability regions. However, the most recent market reports concerning capacity margins were issued under the previous configuration, under which all of Illinois was in the MAIN region.

considered, the planning reserve increases to 21.4%. This compares favorably to the recommended long-term planning reserve margin of 16 to 19% based on the most recent NERC Long-term Reliability Assessment. The same report lists projections of planning reserve margin for the summer of 2010 at 14.8%, without including uncommitted resources. With the uncommitted resources included the planning reserve, the 2010 margin rises to 20.5%. Since MAIN is a summer-peaking region, the winter reserve margins are much higher.

The surrounding regions also report planning reserves ranging from 14.5 to 14.9%, of the same magnitude as MAIN's 14.8% projection, and as these areas have aggregated into larger regions the reserve requirements have decreased (see discussion below). Thus, I conclude that even if 252 MW of Illinois coal generation were to retire, this would not present a reliability problem from a regional capacity perspective.

Sharing of reserves

Any impact of retirements on the ability of Illinois entities to meet their capacity requirement is further diminished by at least three regional initiatives, each of which will increase the effectiveness of resources from the large regional area surrounding Illinois to support system adequacy. First, the former ECAR, MAIN and MAAC reliability regions have been reformed into a single large region reliability organization known as Reliability First, meaning that Illinois (which was in MAIN) now has a much broader capacity pool from which to draw. The MRO region[11], to the north and west of Illinois, is considering consolidation into this larger region. This kind of consolidation generally results in greater levels of reserve sharing and thus boosts reliability throughout the system. Essentially, the diversity of use of resources – i.e., varying times at which systems experience their peak loads – allows for a more efficient sharing of resources across the broader area. This is evidenced by the way in which capacity reserve obligations in PJM have been steadily lowered (on a percentage basis) as the PJM RTO region expanded to include additional utility areas such as American Electric Power,

[11] Formerly known as MAPP

Commonwealth Edison, and Dominion Power--PJM reserve obligations have been reduced from 19% in 1998 to 15.0 in 2005.

Second, the Midwest ISO region is currently planning to coordinate an explicit operating reserve market. This will allow for more efficient use of capacity to support adequacy needs.

Third, the Midwest ISO and the PJM RTO continue to discuss way in which to coordinate their respective market operations, and they have signed agreements with the SPP RTO to further coordinate operations. Such coordination can increase the ability of capacity resources in one region to serve needs in adjacent regions, especially given the diversity in peak load use across such large regions.

Because of all of these trends towards greater cooperation in reserves sharing, and because Illinois is almost invariably is an exporter of power so there are no import constraints, we do not believe that reliability will be threatened by lack of access to adequate reserves with or without the proposed mercury rule.

Rules governing retirements

If, despite all of these factors, a generating unit which is needed for reliability reasons were to be nominated for retirement, either PJM or the Midwest ISO (MISO) can take steps to keep the unit operating, depending on the location of the unit. Indeed, RTOs have done so from time to time. Generally, this involves entering into an agreement with the unit's owner to ensure that the costs of continuing to operate a unit will be recovered, even if the RTO must supplement market or regulated payments for operation with additional compensation.

Thus I conclude that if units are rendered uneconomic by the proposed Illinois mercury rule, but are needed for reliability reasons, either the MISO or PJM market operator has the necessary authority and the procedures in place to either compel or adequately compensate the generation owner to keep the unit on line until an alternative solution can be found.

Retirements unlikely to occur in load pockets due to price signals

The IPM model runs which form the basis for the analysis in the TSD do not represent transmission constraints within, for example, the MANO area which contains Illinois. Thus it may be that there are certain subregions which, for reasons of local transmission or distribution constraints, are particularly vulnerable to reliability problems should generating units in these areas retire. If this were the case, perhaps retirements of small, aging coal plants in these areas would raise some reliability concerns.

However, I do not believe that these concerns would be justified for two reasons. The first is outlined above, which is that the RTOs have the tools and structure in place to prevent retirements of units that are needed for reliability reasons. Secondly, both RTOs operate under a locational electricity pricing system known as LMP, which is designed to produce higher electricity prices in regions that are more expensive to serve. If this is not enough, PJM is moving towards implementation of a locational capacity compensation scheme in PJM, under which generation owners will be paid for their capacity (in addition to their energy) in a way that is designed to compensate generators in capacity-short regions sufficiently to deter retirements and encourage new entry. Thus, I once again conclude that if any specific units are needed for reliability reasons—in this case to ensure local reliability—it would be compensated at a greater rate than would be predicted by the IPM model, and would be unlikely to retire.

Predicted retirements are not unusual

The specific generating units which are predicted by the IPM model to retire as a result of the Illinois mercury rule are Hutsonville Units 5 and 6 (partial) and Meredosia Units 1 through 4. As noted in the TSD, these units are all at least 50 years old and may well be nearing the end of their operating life. Based on data from the IPM model, these units are about 10% less efficient than average for coal-fired power plants in Illinois, and considerably less efficient than newer units. It would not be surprising, especially under conditions of surplus such as those seen in the Illinois region today, to find that such plants are no longer economically justified with or without the proposed rule, especially if there is not some specific reliability-based need for these particular assets. In some cases, units such as these would be replaced with more efficient new plants such as natural gas combined cycle units, or with gas-fired peaking units, at the same location.[12] Such units would offer greater operational flexibility and much lower emissions. Thus, while it is possible that the owners of certain inefficient coal units would find it preferable to take the units out of service rather than to bring them into compliance with new emissions rules, my judgment is that this would not be out of line with the normal evolution of generating assets, may in fact make way for the construction of newer, more efficient units, and in any case would not pose a reliability problem for the state or the region.

New entry unaffected by proposed rule

The final point I would like to make with regard to the reliability impact of the proposed rule is that new generating units are unlikely to be significantly affected by this rule, because they are already required to meet stringent emissions criteria. To the contrary, this rule may give a slight economic boost to new entry if it does, indeed, cause a small number of retirements to be accelerated, or raise local electricity prices by a small amount. Along with this comes greater efficiency, greater operational flexibility, greater unit reliability, and lower emissions. If anything, this would provide a net benefit in terms of electric system reliability in Illinois and the surrounding region.

Conclusions

Based on my analysis of the IPM model data and results, and based on my understanding of market conditions in the MISO and PJM regions, I conclude that the proposed rule will have little if any effect on electric system reliability in the region. I conclude that the number of generating unit retirements caused or accelerated as a result of the rule is very small if any, that there is more than adequate capacity in the region to accommodate any retirements that may occur, and that there are safeguards in place to make sure that retirements will not occur if they would raise reliability concerns.

[12] For example, all units over 50 MW retired between 1999 and 2004 identified EIA Form 860 filing database were replaced with new units mostly gas combine cycle units.

Impacts on the Economy and Employment in Illinois

I have not performed a specific economic modeling study on the impacts of the proposed mercury rule on the economy of the State of Illinois. I do not believe that such a study would be particularly informative as to the impacts attributable to changes in generation costs or prices. As I explained above, the direct impact of the rule in terms of electricity prices and costs to consumers will be quite modest. However, based on a range of existing studies and on closely related modeling analysis performed by Synapse staff in similar cases, I am able to estimate certain of the effects of this rule on the Illinois economy. Many of these direct and indirect economic costs and benefits to the state of Illinois are also modest in scale relative to their uncertainty. As will be explained below, the situation with regard to economic value of the public health benefits of the Proposed Rule is quite another story.

Retail Rate Impact

My estimate of the incremental total retail cost impact from the proposed rule is between zero to $11 million per year in 2006 dollars, over and above the cost impact of the CAIR/CAMR requirements. For perspective, this range represents approximately 0% to 0.1% of the Illinois retail electric bill of $9,359 million per year.[13]

In an earlier study performed for the Citizens Utility Board of Illinois, Synapse estimated the effect on employment in Illinois associated with changes in the total cost of electricity. On the basis of that relationship, this Proposed Rule’s estimated incremental retail cost impact would result in the loss of between zero and about 69 jobs in the state of Illinois. I would caution that even the upper end of this range is quite small relative to the precision of macroeconomic models, and relative to what I assume to be the day-to-day variation in employment in the state. Thus I would conclude that the magnitude of this effect may be statistically indistinguishable from zero impact on employment.

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[13] Total retail electric costs in 2003 according to the US EIA: http://www.eia.doe.gov/cneaf/electricity/esr/esr_tabs.html

Impact of Potential Generating Unit Retirements

The IPM model results reported in the TSD predict that the Proposed Rule may lead to retirement of certain coal plants now operating in Illinois, over and above the potential impact of the CAIR/CAMR requirements, totaling 243 MW or about 0.6% of in-state generating capacity. This includes one "partial retirement" which is wholly an artifact of the model structure. The employment at these units is estimated to total 160 jobs.[14] In addition, these plants purchase goods and services from the economy to operate. If there were a net loss of generating capacity in Illinois, the loss of jobs would exceed the direct decrease in generating plant employment by some factor.

As discussed above, however, my judgment is that the unit retirements are probably overestimated due to limitations of the model, and in any case the prediction that these small, aging, and inefficient coal plants will retire during the next decade is not out of line with normal evolution of the generation stock. Furthermore, were these retirements to occur, it is likely that the retired capacity would be replaced by newer, more efficient plants, quite possibly even in the same location, providing employment benefits associated with plant construction for up to several years. Thus I judge the direct impact in terms of employment at Illinois generating units to be small, if any.

Other employment impacts in Illinois

In addition to the direct impact flowing from employment at generating units, there are a number of beneficial impacts on employment in Illinois that may be expected from the Proposed Rule. These include:

1. Employment gains due to installation and operation of mercury controls.

   Compliance with the Proposed Rule will require certain capital investments in the early years of the Proposed Rule and certain ongoing operating and maintenance costs, the largest of which is likely to be purchase of sorbent. The TSD provides an estimate of the capital cost of incremental Hg controls. Table 8.7 of the TSD estimates this cost at $35.5 million over the CAMR cost of $75.6 million in 2006

[14] TSD at 201

dollars. The Proposed Rule provides considerable flexibility in implementation timing and details, and as a result it is likely that the employment benefit of the capital investment portion of compliance costs, as well as any multiplier effect through the state economy, will be spread over several years.

There are also likely to be annual O&M costs for mercury controls; estimates of these are provided in Table 8.7. These costs include:

- Sorbent cost $23.064 million per year
- Toxecon O&M cost $0.435 million per year
- Ash disposal cost $3.503 million per year

I cannot predict what fraction of this annual expenditure will be for Illinois goods and services, but there will clearly be some local benefit.

2. Impact of Increased Demand for Illinois Coal

The IPM model predicts that there will be an increase in generation from Illinois coal under the Proposed Rule compared to the CAIR/CAMR scenario. The increase varies with the scenario year, ranging from 40 TBtu to 67 TBtu, assuming that all bituminous coal burned in Illinois coal-burning EGUs comes from Illinois.[15] On the other hand, the analysis in Chapter 8 of the TSD suggests that all existing Illinois coal-burning EGUs can meet the Proposed Rule's requirements without changing the type of coal they burn. For purposes of this analysis, I assume a range of incremental use of Illinois coal of zero to 50 TBtu.

The US average as received heat content of bituminous coal is 24 MMBtu/ton.[16] A range of incremental consumption of Illinois coal from zero to 50 TBtu then corresponds to an increase in consumption of Illinois bituminous coal of zero to 2.08 million tons. The 2004 production of bituminous coal in Illinois was 31.5 million tons, which was 79% of total coal production in Illinois that year.[17] This is a

[15] TSD Table 9.10; TSD at 201.
[16] US EIA online glossary, at http://www.eia.doe.gov/glossary/glossary_b.htm.
[17] US EIA Annual Coal Report 2004.

percentage increase of zero to 6.6%. Average direct employment in coal mining in Illinois for 2004 was 3573 jobs.[18] If we assume that 79%, or 2823 jobs, were in bituminous coal mines, a 6.6% increase in production of Illinois bituminous coal production would result in an approximate increase in employment of 186 direct jobs, along with a substantial number of additional jobs in secondary employment.

3. Impact of Enhanced Sport Fishing and Other Wildlife Activities

According to the TSD, "Any improvement, or prevention of loss, to Illinois' fish and wildlife activities through implementation of Illinois' mercury rule could have a positive impact to this important industry."[19] I agree. The relevant wildlife-associated recreation activities include at least sport fishing said to be worth "more than $1.6 billion to the State economy when considering the salaries from jobs created, as well as sales and motor fuel taxes, and State and federal income taxes."[20] However, this includes all such activities in the state, including those on the Great Lakes. Preparing a specific estimate of the likely impact of the Proposed Rule on these expenditures is beyond the scope of this study. However, for illustrative purposes, consider the scenario where the Proposed Rule results in an incremental 1% increase in sport fishing. This would produce an additional stimulus to the state economy of about $16 million per year, and to an incremental increase in employment of about 130 jobs.

4. Impact of Health Benefits

The most significant economic impact to be anticipated from the proposed rule flows from the long-term health and avoided premature mortality benefits of reducing the environmental loading of mercury. Chapter 3 of the TSD reviews several studies of the direct economic cost of mercury exposure, whether due to power plant emissions or other sources. There is wide variation in these estimates, and they were not necessarily specific to Illinois or the Proposed Rule. However, they may be taken as indicative of the hidden costs of mercury emissions associated with human health,

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[18] EIA *Annual Coal Report*, 2004.
[19] TSD at 189.
[20] TSD at 189.

lost IQ points and premature mortality impacts that will be partially abated by the proposed rule.

To estimate the economic value of this benefit, I rely on the results of the very recent NESCAUM/Harvard study[21] cited in the TSD. This study concludes that the *annual* economic benefit of avoided health and mortality impacts is about $182 to $194.5 million per ton of mercury removed.[22] The TSD (p. 29) indicates that the incremental mercury removal due to the proposed rule is approximately 2400 pounds per year relative to the CAMR limit for the first ten years of implementation; the benefits of each ton of avoided mercury emissions will continue to accrue year after year. This leads to a health and avoided mortality benefit from the Proposed Rule which may be valued well into the billions of dollars over 10 years. Estimating the considerable secondary effects of this reduction in adverse health impacts, avoided intellectual impairment and improved productivity is beyond the scope of this study.

In summary, I find that the direct economic losses associated with implementation of the proposed rule to be between zero and 69 jobs due to the retail rate impact of between zero and $11 million, and a maximum of 160 jobs associated with unit retirements should they occur as projected by the IPM model. On the other hand, I find that there are likely to be employment benefits associated with installation, operation and maintenance of mercury control technologies, construction and operation of replacement generation technology, and possibly with the increased use of Illinois bituminous coal. I find that employment benefits associated with increased fishing and tourism due to decreased mercury loading in the Illinois environment and waterways will be on the order of 130 jobs for each 1% increase in recreational fishing. My judgment is that the increase in employment associated with these benefits is likely to more than offset the potential decreases. Additional employment benefits associated with installation and maintenance of mercury controls, and short- and long-term employment associated with construction and

[21] NESCAUM, 2005. *Economic Valuation of Human Health Benefits of Controlling Mercury Emissions from U.S. Coal-Fired Power Plants.* http://www.nescaum.org/documents/rpt050315mercuryhealth.pdf/
[22] Ibid. p. 193.

operation of new power plants, would be likely to put employment gains associated with this rule well in excess of employment losses.

Finally, I conclude that there will be significant long-term economic benefits associated with reduced health care costs, improved productivity and avoided premature mortality due to the proposed rule. These combined benefits would be worth several billion dollars over the first ten years, alone exceeding by over an order of magnitude the implementation cost of the plan during that period. Thus, I expect the Proposed Rule to have a significantly positive and long lasting effect on the economy of the State of Illinois.

Overall Conclusions

My overall conclusions may be summarized as follows:

- The proposed rule will have at most a modest impact on the cost of electricity to consumers, reflecting the relatively modest cost of compliance for Illinois generating companies;
- The proposed rule will not raise system reliability concerns because its overall effect on plant retirements will be small;
- While there may be some negative direct economic and employment-related impacts of the rule flowing from the increased price of electricity and the loss of jobs if power plants do close down, these effects are small and will be overwhelmed by the positive economic impacts of the rule. These positive impacts include (but are not limited to) direct employment benefits, benefits in tourism and recreational fishing, and the substantial economic value of improvements in human health and avoided premature mortality.

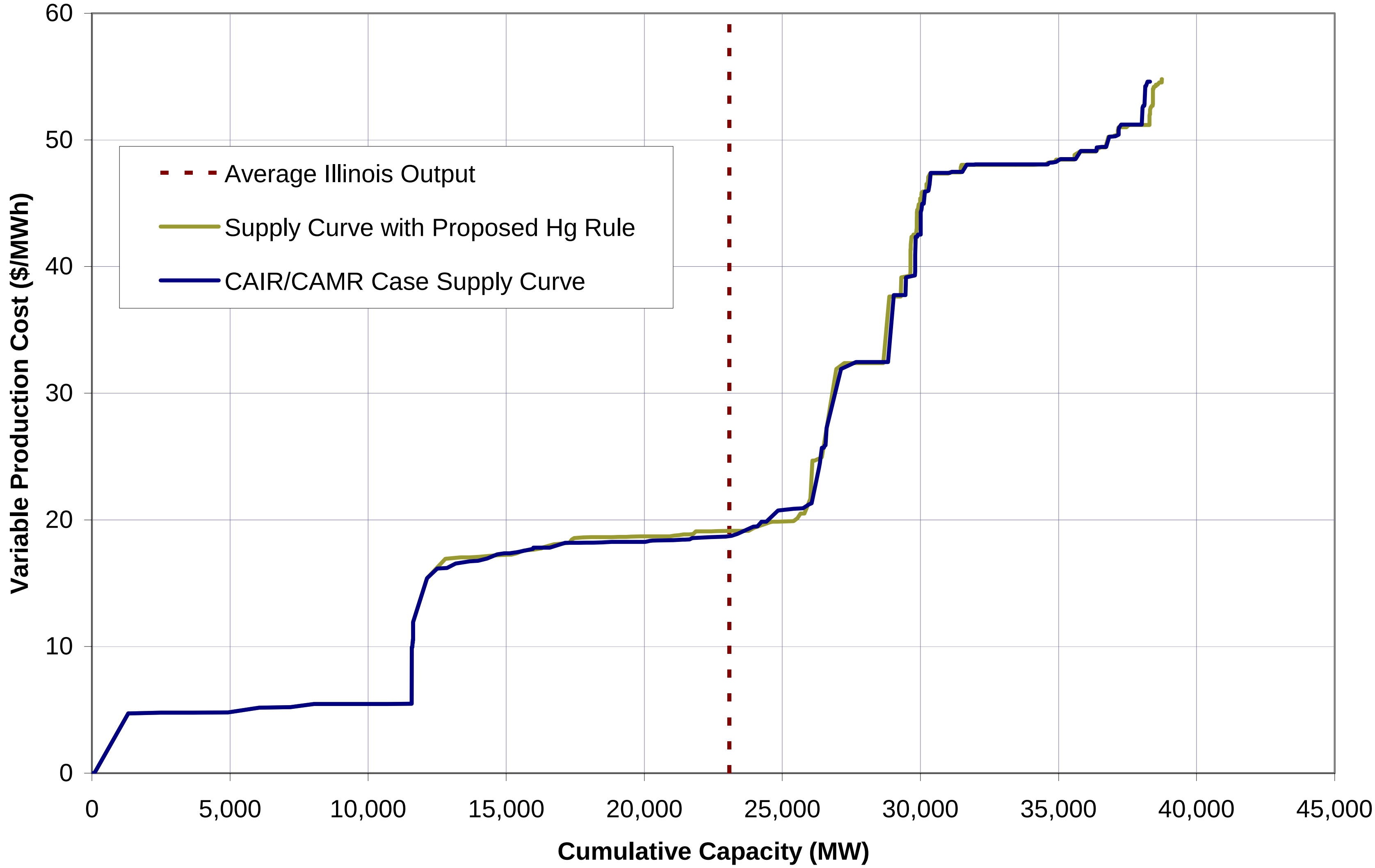

Exhibit EDH-1. Variable cost supply curve for Illinois generating units under the proposed mercury rule, compared with the supply curve under CAIR/CAMR only case. Based on IPM model data and results.

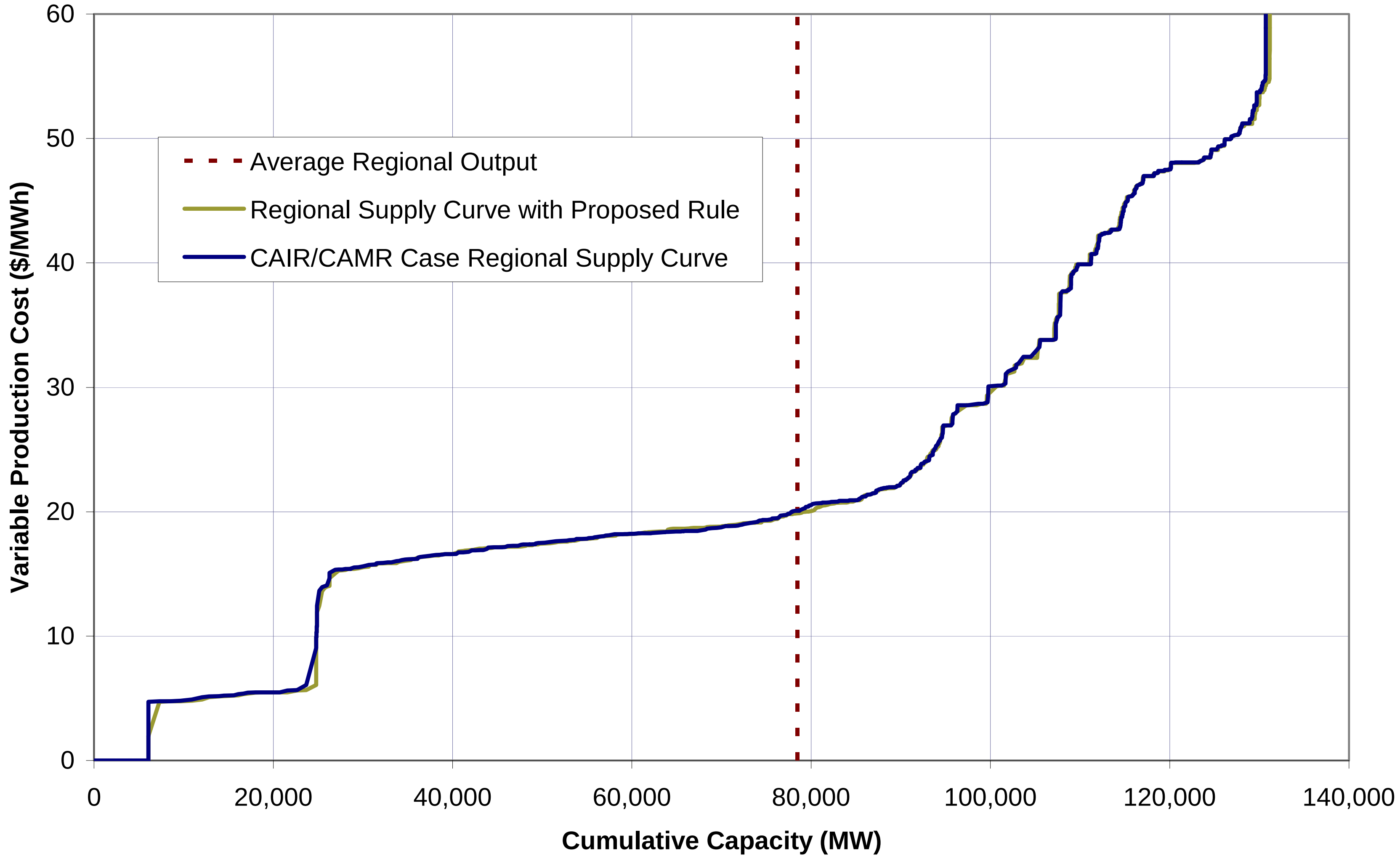

Exhibit EDH-2. Comparison of variable cost supply curves for combined generating stock in six-state region, including Illinois, Indiana, Wisconsin, Iowa, Missouri, and Michigan. Based on IPM model data and results.