

APPENDIX B - Comparison of State Programs in EPA’s Region 5 to Reduce Mercury Emissions from Coal-fired Power Plants

	Wisconsin	Illinois	Indiana	Michigan	Minnesota	Ohio
Mercury Reductions Required	<p>1. <i>Large EGU Mercury Emission Standard</i> - By January 1, 2015, existing coal-fired EGUs with nameplate capacity of 150 MW or greater must achieve a 90% mercury reduction or limit the concentration of mercury emissions to 0.008 pounds mercury per gigawatt-hour. Compliance must be demonstrated annually on a unit-by-unit basis. However, units under common ownership or control can average to meet the mercury emission standard.</p> <p>2. <i>Small EGU Mercury Emission Standard</i> - By January 1, 2015, existing coal-fired EGUs with a nameplate capacity greater than 25 MW but less than 150 MW must achieve a level of mercury emissions defined as BACT.</p> <p>3. New EGUs, proposed after the effective date of the rule, must limit mercury emissions to LAER.</p>	<p>1. 90% as measured from the mercury content of coal combusted or limit the concentration of mercury emissions to 0.008 pounds mercury per gigawatt-hour on a rolling 12-month basis for all units that are in operation as of December 31, 2008.</p> <p>2. Emission averaging, with other units is allowed until December 31, 2013, provided each unit involved achieves a 75% reduction or output emission standard of 0.02 pounds per gigawatt-hour on a rolling 12-month basis.</p> <p>3. New power plants, beginning January 1, 2009, must meet 90% as measured from the mercury content of coal combusted or limit the concentration of mercury emissions to 0.008 pounds mercury per gigawatt-hour on a rolling 12-month basis upon start-up. This requirement does not apply to replacement of units at an existing power plant.</p>	<p>Reductions that meet the annual Indiana mercury emission budget established in the CAMR:</p> <p>Baseline: 4,884 lbs.</p> <p>2010: 4,196 lbs. (14.1%)</p> <p>2018: 1,656 lbs. (66.1%)</p>	<p>1. 90% reduction from a baseline based on mercury in coal combusted or output based emission standard of 0.008 pounds per gigawatt-hour annual average.</p> <p>2. New units (after January 30, 2004) may be subject to more stringent requirements.</p>	<p>90% reduction from mercury emitted from six units located at the three largest power plants in Minnesota. This action will result in a 70% reduction of mercury emissions from coal-fired power plants in Minnesota.</p>	<p>Reductions that meet the Ohio mercury emission budget established in the CAMR:</p> <p>Baseline: 7,109 lbs.</p> <p>2010: 4,114 lbs. (42.1%)</p> <p>2018: 1,624 lbs. (77.2%)</p>
Mercury Reduction	1. Large EGU and small EGU mercury emission	1. Achieve the required reductions by July 1,	Achieve the annual mercury emission budget	1. Achieve the required reductions by January 1,	1. For units equipped with a spray dryer and fabric	Achieve the annual mercury emission budget

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Schedule	standards must be achieved by January 1, 2015. 2. For large units, an optional multipollutant compliance pathway extends compliance with the mercury emission standard until January 1, 2021.	2009. 2. If employing a multipollutant approach, achieve reductions by January 1, 2015. 3. New power plants can meet a temporary technology standard until January 1, 2019.	according to the schedule established in the CAMR – 2010 and 2018.	2015. 2. Prior to 2015, emission caps are set by distributing the state CAMR budget based on adjusted baseline heat input to all affected electrical generating units. 3. In 2015 and beyond, source specific caps set for each unit based on either 90% reduction from a baseline of mercury in coal combusted or output based emission standard of 0.008 pounds per gigawatt-hour.	filter (dry scrubbed units) submit plan by December 31, 2007, and implement plan by December 31, 2010. If two units owned, implementation at one by December 31, 2009. 2. For wet scrubbed units, plan required by December 31, 2009, and implemented by December 31, 2014. 3. The required mercury reduction level for each unit is fixed in a permit after completion of a start-up period and reflects emission monitoring and expected performance over the upcoming five-year period.	according to the schedule established in the CAMR – 2010 and 2018.
Trading Limitations	Trading not included.	No interstate trading.	No limitation. Compliance through regulation that follows EPA's model rule which allows participation in a national trading program.	No interstate trading.	Interstate trading allowed under a CAMR federal implementation plan.	No limitation. Compliance through regulation that follows EPA's model rule which allows participation in a national trading program.
Allowance Allocation or Emission Cap Methodology	Since CAMR vacated no allowances or emission cap related to the vacated CAMR.	Allowance allocations are not a feature of the Illinois mercury regulation.	1. Indiana follows EPA's model rule. The only difference is a 1% set-aside of the annual state-wide mercury emission budget available to clean coal technology units for the years 2010 through 2021. 2. The heat input approach outlined in EPA's model rule is used	1. In Michigan, affected units do not receive allocations. Instead annual mercury emission caps are established. 2. These emission caps are set by a procedure that ensures that the CAMR annual emission budget is not exceeded. 3. Annual determination and written notification	Minnesota is not proposing to submit a state plan to implement the CAMR therefore, allocation of allowances will be under a federal implementation plan and mirror EPA's model rule methodology.	1. Ohio follows EPA's model rule. 2. The heat input approach outlined in EPA's model rule is used in their allocation methodology however, there is no adjustment for fuel type. 3. Retired units receive allowance allocations that do not sunset.

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			in their allocation methodology however, there is no adjustment for fuel type. 3. Retired units receive allowance allocations that do not sunset.	provided for the upcoming year with opportunity for appeal. 4. Highest three year heat input average from the most recent five year period. 5. Retired units do not receive an emission cap.		
Flexibility	<p>1. Compliance must be demonstrated annually on a unit-by-unit basis. However, large units under common ownership or control can average to meet the mercury, nitrogen oxides (NOx) and sulfur dioxide (SO2) emission standards. Averaging can only occur among those units participating within the same compliance pathway.</p> <p>2. Under the multipollutant compliance pathway a 70% mercury removal from coal is established for 2015.</p> <p>3. An interim 80% mercury removal from coal is required by 2018</p> <p>4. Under the multipollutant compliance pathway, 90% mercury removal from coal combusted must be achieved by 2021.</p> <p>5. Early emission</p>	<p>1. A multipollutant approach is available as an alternative provided notice is given by December 31, 2007. This is a system-wide approach and once a commitment is made, opting out is not possible. Units planned for permanent shutdown can be exempted provided notice is received by June 30, 2009, and shutdown occurs within the next two years. There are emission standards for nitrogen oxides (NOx), sulfur dioxide (SO2) and mercury that each unit must achieve. Mercury control installation must occur between July 1, 2009, and December 31, 2014. Every unit must achieve compliance with the emission standard or reduction of mercury input standard beginning January 1, 2015.</p> <p>2. New power plants can</p>		<p>1. Multipollutant proposal that achieves a minimum of 75% reduction on an affected unit may be substituted.</p> <p>2. Small units, less than 9 lbs. per year, may have an alternative plan.</p> <p>3. Technical or economic exception possible.</p> <p>4. Exceptional circumstances adjustment is available in 2016 and 2017.</p>	<p>1. Extension of deadlines allowed if necessary however, final compliance deadline cannot be extended more than 12 months.</p> <p>2. Power plants with wet scrubbed units can consider substitute units for control in lieu of a targeted unit.</p>	

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	reduction credits can be used to achieve the mercury reductions under the multipollutant pathway.	meet a temporary technology based standard until December 31, 2018, provided they are achieving Best Available Control Technology (BACT) for SO ₂ , NO _x and particulate matter (PM) and employ an approved mercury control technology.				
Compliance Demonstration	Mercury emissions for compliance determined by monitoring, recordkeeping and reporting requirements in the CAMR.	Mercury emissions for compliance determined by monitoring, recordkeeping and reporting requirements in the CAMR.	Mercury emissions for compliance determined by monitoring, recordkeeping and reporting requirements in the CAMR.	1. Mercury emissions for compliance determined by monitoring requirements in the CAMR. 2. Annual compliance demonstration plan beginning October 2009. 3. Annual and quarterly emission reporting required beginning April 2010.	Mercury emissions for compliance determined by monitoring, recordkeeping and reporting requirements in the CAMR.	Mercury emissions for compliance determined by monitoring, recordkeeping and reporting requirements in the CAMR.
Adopted or Proposed	Rule to be effective in 2008.	Rule effective December 2006.	Rule adopted October 2007.	Rule to be effective in 2008.	Mercury Emission Reduction Act of 2006 – Signed May 11, 2006	Rule effective May 2007.
Additional Comments	1. BACT proposals for small EGUs are required within 30 months of the effective date of the rule. 2. Large EGUs must identify whether they will follow the multipollutant compliance pathway within 24 months of the effective date of the rule. 3. The mercury reduction requirements and schedule will be reviewed in 2013.			1. System-wide averaging or a multipollutant proposal can be disapproved if local mercury impacts a factor. 2. Units involved in a multipollutant proposal, subject to a small unit alternative or operating under a technical or economic exception cannot be involved in a system-wide average compliance approach.	1. The Minnesota Pollution Control Agency reviews plans and makes recommendations to the Minnesota Public Utilities Commission which has approval authority. 2. Owners can recover costs for monitoring, control equipment, construction, operation and maintenance, relevant studies and other related costs incurred prior to plan	

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				3. Mercury pretreatment credit available.	approval. 3. Multipollutant control proposals submitted with a mercury plan may also qualify for cost recovery.	
CAMR 1999 Baseline Emissions	2,264 lbs.	5,989 lbs.	4,884 lbs.	3,081 lbs.	1,265 lbs.	7,109 lbs.
CAMR 2010 – 2017 Emission Budget (% reduction)	1,781 lbs. (21.4%)	3,188 lbs. (46.8%)	4,196 lbs. (14.1%)	2,606 lbs. (15.4%)	1,390 lbs. (+ 9.9%)	4,114 lbs. (42.1%)
CAMR 2018 and thereafter Emission Budget (% reduction)	702 lbs. (68.9%)	1,258 lbs. (79.0%)	1,656 lbs. (66.1%)	1,028 lbs. (66.6%)	550 lbs. (56.5%)	1,624 lbs. (77.2%)
Coal Use Characterization for Electrical Energy Production – Data from Energy Information Administration	2005 Coal Consumption for Electric Power – 24,615 (thousand short tons) 2005 Coal Received from Colorado, Montana and Wyoming for Electricity Generation – 22,493 (thousand short tons)	2005 Coal Consumption for Electric Power – 53,822 (thousand short tons) 2005 Coal Received from Colorado, Montana and Wyoming for Electricity Generation – 45,699 (thousand short tons)	2005 Coal Consumption for Electric Power – 60,011 (thousand short tons) 2005 Coal Received from Colorado, Montana and Wyoming for Electricity Generation – 11,843 (thousand short tons)	2005 Coal Consumption for Electric Power – 36,273 (thousand short tons) 2005 Coal Received from Colorado, Montana and Wyoming for Electricity Generation – 28, 820 (thousand short tons)	2005 Coal Consumption for Electric Power – 20,008 (thousand short tons) 2005 Coal Received from Colorado, Montana and Wyoming for Electricity Generation – 19,268 (thousand short tons)	2005 Coal Consumption for Electric Power – 59,607 (thousand short tons) 2005 Coal Received from Colorado, Montana and Wyoming for Electricity Generation – 11,659 (thousand short tons)