EXHIBIT C

RECEIVED
MAR 09 2015
DEPARTMENT OF ENVIRONMENTAL QUALITY
STATE A Q PROGRAM

P4 Production, LLC

Soda Springs Plant
1853 Highway 34
P.O. Box 816
Soda Springs, Idaho 83276-0816
Phone: (208) 547-4300
Fax: (208) 547-3312

March 5, 2015

VIA CERTIFIED MAIL;
RETURN RECEIPT REQUESTED – **7013 1710 0000 3213 0898**

Mr. Bill Rogers
Air Quality Division
Department of Environmental Quality
1410 North Hilton
Boise, ID 83706

RE: MBACT Tier II Permit Application

Dear Mr. Rogers:

Per IDAPA 58.01.01.402.a.ii. P4 Production, LLC (P4) is submitting the enclosed Tier II Permit application and updated Mercury Best Available Control Technology (MBACT) Analysis. The intent of this application is to amend P4's current Tier II MBACT Permit No. T2-2012.0016 (the Permit), issued March 4, 2014, to incorporate additional information obtained during the initial compliance test required by the current Tier II permit.

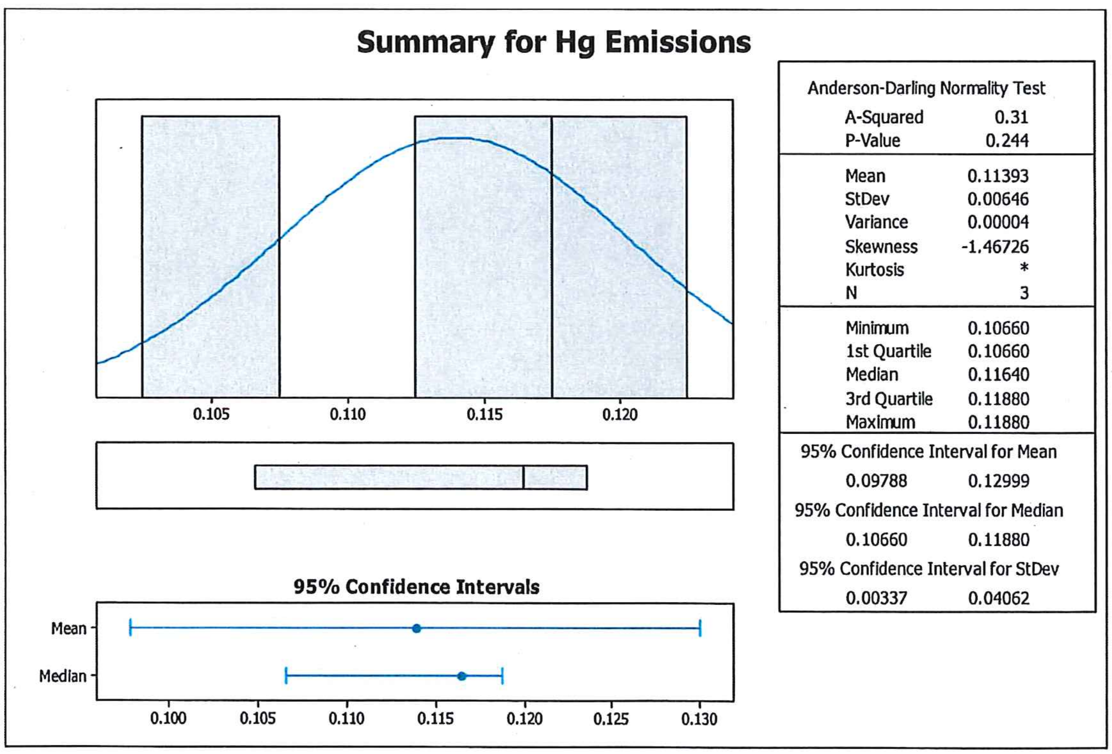
The initial permit application, submitted on April 6, 2012, included a complete MBACT analysis, and, pursuant to a request from the Department, a proposed limit for mercury emissions. That proposed emission limit was based on a single emissions test conducted in 2002 and was intended to reflect the amount of mercury expected to be emitted from the plant at maximum annual operating rates. The emission limit was calculated by multiplying the 2002 emission rate (lb Hg emitted per ton of ore fed to the kiln) by maximum annual ore feed rate to the kiln to obtain an annual emission limit of 746.4 pounds of mercury per any consecutive 12 calendar month period. The Permit was issued on March 4, 2014.

As P4 discussed with the Department during the development of the Permit, there is substantial variability in the operation of the plant, including the nodulizing kiln. Given the scale of the operations and the process rates of the kiln, such variability can result in substantial differences between individual samples of various process streams, including emissions. The initial compliance testing in August of 2014 measured a higher mercury emission rate (lb Hg emitted per ton of ore fed to the kiln) than that measured in 2002. Applying that emission rate to the mass emission rate in the Permit, then, will have the effect of limiting the throughput at the kiln.

As stated in P4's cover letter for the August stack test report, dated October 24, 2014, P4's understanding is that the Permit was intended to reflect the Department's determination that the current operations of the kiln constituted MBACT and that the Permit would authorize P4's current process and emissions. Though P4 installed an SO2 scrubbing process in 2005 and has moved twice to different phosphate ore mines, the kiln process has not been modified and remains unchanged since 2002 in terms of capacity and potential to emit mercury.

In a recent meeting held with the Department on February 17, 2015, P4 expressed its concerns around the emission limit in the Permit given the variability of operating conditions and a lack of a proper amount of data to reliability establish an appropriate mass emission limit. In response to the Department's suggestion, P4 is submitting this permit application to amend the Permit by adopting a higher emission limit based on the results of stack testing conducted in 2014 that would continue to authorize current operating rates and continue the required compliance testing until such time as sufficient data is collected that would allow for the development of a more accurate limit.

To develop a proposed revised emission limit in the amended permit, P4 used the mean plus three sigma at the upper end of the 95% confidence interval for both parameters measured during the 2014 compliance testing as shown below:



95% Confidence Interval for Mean = 0.12999

95% Confidence Interval for StDev = 0.04062

Hg Emission Limit = (0.12999) + 3*(0.04062) = 2205.4 lb/year

Total Kiln Feed remains the same as (249.9 ton/hr) * (8760 hours) = 2,189,214 tons/year

The updated MBACT analysis was based on actual mercury emissions and the highest measured emission of .1188 lb/hr from December 2014 testing. P4 intends to continue stack testing as required by the Permit.

When the results of the 2014 compliance testing are applied to the current annual emission limit in the Permit, P4 will be required to substantially reduce operating rates, with the maximum impact on operating rates occurring in August 2015. Therefore, P4 respectfully requests all effort be made to respond to this application in a timely manner as to avoid the impact to current operations by August of this year.

In addition, Condition 2.7 of the existing Tier II operating permit requires that mercury emissions tests of kiln stack emissions "measure total mercury emissions in pounds per hour and determine particle bound mercury, oxidized mercury and elemental mercury emissions rates". Developed to measure elemental, oxidized and particle-bound mercury emissions from coal-fired stationary sources, ASTM D6784-02 (Ontario Hydro method) is the sole test method capable of yielding these results. Repeated mercury emissions tests of the Main Kiln stacks using ASTM D-6784-02 demonstrate that elemental mercury consistently accounts for 95% – 97% of total mercury emissions. P4 suggests that this consistency of mercury emissions partitioning to the elemental species enables flexibility in the selection of the test method employed to demonstrate compliance of the Kiln Hydrosonics with the emissions limit imposed by the revised Tier II Operating Permit. P4 further suggests that other methods developed to measure mercury emissions from coal-fired sources which measure elemental mercury emissions can be considered suitable for compliance demonstration because of the consistent partitioning of Main Kiln mercury emissions almost entirely to the elemental species.

P4 proposes the use of USEPA Method 30B as a suitable alternative method to demonstrate compliance of the Kiln Hydrosonics with the emissions limit imposed by the new Tier II operating permit. USEPA identifies the method as suitable to measure elemental mercury emissions from coal-fired stationary sources, much the same as ASTM D6784-02. The Method incorporates performance-based QA/QC measures including paired-train sampling with paired-sample Relative Deviation limits and sample spiking /recovery requirements for validation of test results. These built-in quality elements, which do not exist in ASTM D6784-02, provide a direct measure of accuracy and consistency of result which is not available with ASTM D6784-02.

Previous discussions with IDEQ have included questions about an impact analysis. As such, P4 has included a preliminary assessment of local impacts from mercury emitted from the Soda Springs facility along with a copy of Dr. Steve Lindberg's presentation to the Board of Environmental Quality on February 12, 2009.

In accordance with IDAPA 58.01.01.123, I certify based on information and belief formed after reasonable inquiry, that the statements and information in this document are true, accurate, and complete. If you have any questions regarding this submittal, please contact Mr. Jim McCulloch at (208) 547-1233.

Sincerely,

Roger W. Gibson
Vice President, Operations

enclosures

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Cover Sheet for Air Permit Application – Tier II **Form CSTII**

Please see instructions on page 2 before filling out the form.

COMPANY NAME, FACILITY NAME, AND FACILITY ID NUMBER			
1. Company Name	P4 Production, LLC		
2. Facility Name	Soda Springs Facility	3. Facility ID No.	029-00001
4. Brief Project Description - One sentence or less	MBACT Analysis and Tier II Permit Update		

PERMIT APPLICATION TYPE

5. ☐ Initial Tier II Permit ☒ Tier II Renewal: Permit No.: T2-2012.0016 Date Issued: March 4, 2014
☐ Required by Enforcement Action – Case No. ____ ☐ Bank an Emissions Reduction Credit (Section 461)
☐ Tier II Facility Emissions Cap Permit Application ☐ Synthetic Minor Permit Application ☐ SIP Permit Application Required by DEQ

FORMS INCLUDED

Included	N/A	Forms	DEQ Verify
☒	☐	Form CSTII – Cover Sheet	☐
☒	☐	Form GI – Facility Information	☐
☒	☐	Form EU0 – Emissions Units General	☐
☐	☒	Form EU1– Industrial Engine Information Please specify number of EU1s attached: ____	☐
☐	☒	Form EU2– Nonmetallic Mineral Processing Plants Please specify number of EU2s attached: ____	☐
☐	☒	Form EU3– Spray Paint Booth Information Please specify number of EU3s attached: ____	☐
☐	☒	Form EU4– Cooling Tower Information Please specify number of EU4s attached: ____	☐
☐	☒	Form EU5 – Boiler Information Please specify number of EU5s attached: ____	☐
☐	☒	Form CBP– Concrete Batch Plant Please specify number of CBPs attached: ____	☐
☐	☒	Form HMAP – Hot Mix Asphalt Plant Please specify number of HMAPs attached: ____	☐
☐	☒	PERF – Portable Equipment Relocation Form	☐
☐	☒	Form AO – Afterburner/Oxidizer	☐
☐	☒	Form CA – Carbon Adsorber	☐
☒	☐	Form CYS – Cyclone Separator	☐
☐	☒	Form ESP – Electrostatic Precipitator	☐
☐	☒	Form BCE– Baghouses Control Equipment	☐
☒	☐	Form SCE– Scrubbers Control Equipment	☐
☒	☐	Form VSCE – Venturi Scrubber Control Equipment	☐
☐	☒	Form CAM – Compliance Assurance Monitoring	☐
☒	☐	Forms EI-CP1 - EI-CP4– Emissions Inventory– criteria pollutants (Excel workbook, all 4 worksheets)	☐
☒	☐	PP – Plot Plan	☐
☐	☒	Forms MI1 – MI4 – Modeling (Excel workbook, all 4 worksheets)	☐
☒	☐	Form FRA – Federal Regulation Applicability	☐

Instructions for Form CSTII

This form is the cover sheet for an air quality permit application. It provides DEQ with basic information regarding the company and the proposed permitting action. This form helps DEQ efficiently determine whether the application is administratively complete. This form also provides the applicant with a list of forms available to aid the applicant to successfully submit a complete application.

Company Name, Facility Name, and Facility ID Number

1-3. Provide the name of your company, the name of the facility (if different than company name), and the facility identification (ID) number (Facility ID No.) in the boxes provided. The facility ID number is also known as the AIRS number or AIRS/AFS number (example: 095-00077). If you already have a permit, the facility ID number is located in the upper right hand corner of the cover page. The facility ID number must be provided unless your facility has not received one, in which case you may leave this box empty. **Use these same names and ID number on all forms**. This is useful in case any pages of the application are separated.

4. Provide a brief description of this permitting project in one sentence or less. Examples might be "Initial Tier II operating permit required by DEQ to protect an ambient standard" or "Tier II operating permit renewal." **This description will be used by DEQ as a unique identifier for this permitting project, in conjunction with the name(s) and ID number referenced in 1-3.** You will need to put this description, using the exact same words, on all other forms that are part of this project application. This is useful in case any pages of the application are separated.

Permit Application Type

5. Provide the reason you are submitting the permit application by checking the appropriate box and filling in the number and/or date if needed.

Forms Included

Check the "Included" box for each form included in this permit to construct application. If there are multiples of a form for multiple units of that type, check the box and fill in the number of forms in the blank provided.

The "N/A" box should only be checked if the form is absolutely unnecessary to complete the application. Additional information may be requested.

Processing Fee

A Tier II operating permit processing fee shall be payable in accordance with IDAPA 58.01.01.407 and 408. The processing fee can be paid by check, credit card, or Electronic Funds Transfer (EFT). If you choose to pay by credit card or EFT, please refer to the following Access Idaho link:
https://www.accessidaho.org/secure/deq/payport/item.html?id=511
If you choose to pay by check, send the fee payment to the following address:

Air Quality Tier II Fees
Fiscal Office
Department of Environmental Quality
1410 N. Hilton
Boise, ID 83706-1255

Submit Application

When complete, submit the hardcopy application certified by a responsible official (as defined in IDAPA 58.01.01.006.94), to:

Air Quality Program Office – Application Processing
Department of Environmental Quality
1410 N. Hilton
Boise, ID 83706-1255

Note: **If this permitting action is a Tier II modification that requires a PTC, the PTC application fee must be submitted along with the certified hardcopy application. Refer to Form –**

CSPTC for PTC application fee submission instructions.

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

General Information **Form GI**
Revision 7
2/18/10

Please see instructions on page 2 before filling out the form.

All information is required. If information is missing, the application will not be processed.

IDENTIFICATION

1. Company Name	2. Facility Name:
P4 Production, LLC	Soda Springs Facility
3. Brief Project Description:	MBACT Analysis and Tier II Permit Update

FACILITY INFORMATION

4. Primary Facility Permit Contact Person/Title	Jim McCulloch		Sr. Environmental Engineer	
5. Telephone Number and Email Address	208-547-1233		james.r.mcculloch@monsanto.com	
6. Alternate Facility Contact Person/Title	Angela Aalbers		ESH Business Unit Lead	
7. Telephone Number and Email Address	(208) 547-1250		angela.renee.aalbers@monsanto.com	
8. Address to Which the Permit Should be Sent	1853 Highway 34 North, PO Box 816			
9. City/County/State/Zip Code	Soda Springs	Caribou	Idaho	83276
10. Equipment Location Address (if different than the mailing address above)	1853 Highway 34 North, PO Box 816			
11. City/County/State/Zip Code	Soda Springs	Caribou	Idaho	83276
12. Is the Equipment Portable?	☐ Yes ☒ No			
13. SIC Code(s) and NAICS Code	Primary SIC: 2819	Secondary SIC:	NAICS: 325188	
14. Brief Business Description and Principal Product	Elemental phosphorus production			
15. Indentify any adjacent or contiguous facility that this company owns and/or operates	N/A			
16. Specify the reason for the application	☐ Permit to Construct (PTC) For Tier I permitted facilities only: If you are applying for a PTC then you must also specify how the PTC will be incorporated into the Tier I permit. ☐ Incorporate the PTC at the time of the Tier I renewal ☐ Co-process the Tier I modification and PTC ☐ Administratively amend the Tier I permit to incorporate the PTC upon your request (IDAPA 58.01.01.209.05.a, b, or c) ☐ Tier I Permit ☒ Tier II Permit ☐ Tier II/Permit to Construct			

CERTIFICATION

In accordance with **IDAPA 58.01.01.123** (Rules for the Control of Air Pollution in Idaho), I certify based on information and belief formed after reasonable inquiry, the statements and information in the document(s) are true, accurate, and complete.

17. Responsible Official's Name/Title	Roger W. Gibson		Vice President, Operations
18. Responsible Official Address	1853 Highway 34 North, PO Box 816		
19.Responsible Official Telephone Number	(208) 547-4300		
20. Responsible Official Email Address	roger.w.gibson@monsanto.com		
21. Responsible Official's Signature	Roger Gibson	Date:	3/5/15

22. ☒ Check here to indicate that you would like to review the draft permit prior to final issuance.

Instructions for Form GI

This form is used by DEQ to identify a company or facility, equipment locations, and personnel involved with the permit application. Additional information may be requested.

1 – 3. Please fill in the same company name, facility name (if different), and brief project description as on Form CS. This is useful in case any pages of the application are separated.

4. Name of the primary person who should be contacted regarding this permit.

5. Telephone number and e-mail address of person listed in 4.

6. Name of the person who should be contacted if the person listed in 4 is not available.

7. Telephone number and e-mail address of person listed in 6.

8 - 9. Address to which DEQ should mail the permit.

10 – 11. Physical address at which the equipment is located (if different than 9).

12. If the equipment is portable (such as an asphalt plant), identify by marking "yes." If there are other locations where you know the portable equipment will be used, attach a Portable Equipment Relocation Form (PERF) to list those locations. An electronic copy of the PERF can be obtained from the DEQ website at http://www.deq.idaho.gov/media/576773-ptc_relocation.pdf or http://www.deq.idaho.gov/media/576769-ptc_relocation.doc (for Word format).
Important note: In addition to being submitted with this PTC application, a PERF must also be completed and filed at DEQ at least 10 days in advance of relocating any of the equipment covered in this application.

13. Provide the Standard Industrial Classification (SIC) code and the North American Industry Classification System (NAICS) code for your plant. NAICS codes can be found at http://www.census.gov/epcd/naics02/naicod02.htm. If a secondary SIC code is applicable, provide it also.

14. Describe the primary activity and principal product of your business as it relates to the SIC code or NAISC code listed in line 13.

15. Please indicate if there are any other branches or divisions of this company located on adjacent or contiguous properties.

16. Check the box which describes the type of permit application.

For existing Tier I facilities that are applying for a PTC the applicant must specify how the PTC will be incorporated to the Tier I permit (IDAPA 58.01.01.209.05; Call the Air Permit Hotline if you have questions 1-877-573-7648).

17 – 21. Provide the name, title, telephone number, email address of the facilities responsible official. Responsible official is defined in IDAPA 58.01.01.006.94. The Responsible official must sign and date the application before it is submitted to DEQ.

22. If you would like to review a draft before the final permit is issued, check this box.

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION		
1. Company Name: P4 Production, LLC	2. Facility Name: Soda Springs Facility	3. Facility ID No: 029-00001
4. Brief Project Description:	MBACT Analysis and Tier II Permit Update	

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION	
5. Emissions Unit (EU) Name:	PHOSPHATE ORE NODULIZING KILN
6. EU ID Number:	P-1
7. EU Type:	☐ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8. Manufacturer:	ALLIS CHAMBERS
9. Model:	
10.. Maximum Capacity:	300 MMBTU/HR
11. Date of Construction:	1965
12. Date of Modification (if any):	
13. Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT	
14. Control Equipment Name and ID:	C-1 Dust Knockout Chamber
15. Date of Installation:	1965 16. Date of Modification (if any):
17. Manufacturer and Model Number:	Allis Chambers
18. ID(s) of Emission Unit Controlled:	P-1
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency						

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency. See attached MBACT Determination

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)	
22. Actual Operation:	7884 HOURS/YEAR
23. Maximum Operation:	8760 HOURS/YEAR

REQUESTED LIMITS	
24. Are you requesting any permit limits?	☒ Yes ☐ No (If Yes, indicate all that apply below)
☐ Operation Hour Limit(s):	
☐ Production Limit(s):	
☐ Material Usage Limit(s):	
☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
☒ Other:	183 LB/MONTH ON A 12-MONTH ROLLING AVERAGE
25. Rationale for Requesting the Limit(s):	SEE ATTACHED MBACT DETERMINATION

Instructions for Form EU0

This form provides DEQ with information about an emissions unit. An emissions unit is the equipment or process that generates emissions of regulated air pollutant(s). This form is used by the permit writer to become familiar with the emissions unit (EU). This form is also used by DEQ to identify the control equipment and the emission point (stack or vent) used for the emission unit(s) proposed in this permit application. This form also asks for supporting documents to verify stated control efficiencies and details about the emission point. Additional information may be requested.

1 - 4. Provide the same company name, facility name (if different), facility ID number, and brief project description as on Form CS in the boxes provided. This is useful in case any pages of the application get separated.

5. Provide the name of the emissions unit (EU), such as "Union boiler," etc. A separate EU0 form is required for each emissions unit.

6. Provide the identification (ID) number of the EU. It can be any unique identifier you choose; however, this ID number should be unique to this EU and should be used consistently throughout this application and any other air quality permit application(s) (e.g., operating permit application) to identify this EU.

7. Indicate the type of EU by checking the appropriate box (e.g., a new source to be constructed, an unpermitted existing source (as-built) applying for the first time, or an existing permitted source to be modified). If the EU is being modified, indicate on the form the most recent permit issued for the EU.

8. Provide the manufacturer's name for the EU. If the EU is custom-designed or homemade, indicate so.

9. Provide the model number of the EU. If the EU is custom-designed or homemade, indicate so.

10. Provide the maximum capacity of the EU. For example, a boiler's rated capacity may be modified in units of MMBtu/hr in terms of heat input of natural gas; an assembly line capacity may be in parts produced per day. Capacity should be based on a rated nameplate or as stated in the manufacturer's literature.

11. The date of construction is the month, day, and year in which construction or modification was commenced.

Definitions:

Construction fabrication, erection, or installation of an affected facility.

Commenced an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.

Modification any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted to the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) to the atmosphere not previously emitted.

12. If the EU has been or will be modified, provide the month, day, and year of the most recent or future modification as defined in IDAPA 58.01.01.006.

13. Indicate if emissions from the EU are controlled by air pollution control equipment. If the answer is yes, complete the next section. If the answer is no, go to line 18.

14. Provide the name of the air pollution control equipment (e.g., wet scrubber) and the control equipment's identification number. This identification number should be unique to this air pollution control equipment and should be used consistently throughout this and all other air quality permit applications (e.g., operating permit application) to identify this air pollution control equipment.

15. Provide the date the air pollution control equipment was installed.

16. If the air pollution control equipment has been modified, provide the date of the modification.

17. Provide the name of the manufacturer and the model number for the air pollution control equipment.

18. If this air pollution control equipment controls emissions from more than this EU, provide the identification number(s) of the other EU(s).

19. Indicate if this air pollution control equipment operates on a schedule different from the EU(s) it controls.

20. Indicate if the air pollution control manufacturer guarantees the control efficiency of the control equipment. If the answer is yes, attach the manufacturer's guarantee and label it with the air pollution control equipment identification number. Indicate the control efficiency for the target pollutant(s).

21. If the control efficiency of the air pollution control equipment is not guaranteed, attach the design specifications and any performance data to support the control efficiency stated in part 16. Label the supporting documentation with the air pollution control equipment identification number.

22. Provide the projected actual operating schedule for the emission unit in hours/day, hours/year, or other.

23. Provide the maximum operating schedule for the emission unit in hours/day, hours/year, or other.

24. If you are requesting to have limits placed on this EU, mark "Yes." Then, check the applicable requested limit(s) and provide the limit(s). For example, production limits may be in terms of parts produced per year, material usage limits may be in gallons per day.

25. Please provide the reason you are requesting limits, if any. This helps DEQ and the applicant determine whether the limits are necessary, and if they will accomplish the desired purpose. Provide supporting documentation (calculations, modeling assessment, regulatory review, etc.) for each limit requested.

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
P4 Production, LLC	Soda Springs Facility	029-00001
4. Brief Project Description:	MBACT Analysis and Tier II Permit Update	

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	PHOSPHATE ORE NODULIZING KILN
6.	EU ID Number:	P-1
7.	EU Type:	☐ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	ALLIS CHAMBERS
9.	Model:	
10..	Maximum Capacity:	300 MMBTU/HR
11.	Date of Construction:	1965
12.	Date of Modification (if any):	
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	C-2 North Spray Tower	
15. Date of Installation:	1999	16. Date of Modification (if any):
17. Manufacturer and Model Number:	Monsanto	
18. ID(s) of Emission Unit Controlled:	P-1	
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No	
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)	

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency						

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency. See attached MBACT Determination

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	7884 HOURS/YEAR
23.	Maximum Operation:	8760 HOURS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☒ Yes ☐ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☒ Other:	183 LBS/MONTH ON A 12-MONTH ROLLING AVERAGE
25.	Rationale for Requesting the Limit(s):	SEE ATTACHED MBACT DETERMINATION

Instructions for Form EU0

This form provides DEQ with information about an emissions unit. An emissions unit is the equipment or process that generates emissions of regulated air pollutant(s). This form is used by the permit writer to become familiar with the emissions unit (EU). This form is also used by DEQ to identify the control equipment and the emission point (stack or vent) used for the emission unit(s) proposed in this permit application. This form also asks for supporting documents to verify stated control efficiencies and details about the emission point. Additional information may be requested.

1 - 4. Provide the same company name, facility name (if different), facility ID number, and brief project description as on Form CS in the boxes provided. This is useful in case any pages of the application get separated.

5. Provide the name of the emissions unit (EU), such as "Union boiler," etc. A separate EU0 form is required for each emissions unit.

6. Provide the identification (ID) number of the EU. It can be any unique identifier you choose; however, this ID number should be unique to this EU and should be used consistently throughout this application and any other air quality permit application(s) (e.g., operating permit application) to identify this EU.

7. Indicate the type of EU by checking the appropriate box (e.g., a new source to be constructed, an unpermitted existing source (as-built) applying for the first time, or an existing permitted source to be modified). If the EU is being modified, indicate on the form the most recent permit issued for the EU.

8. Provide the manufacturer's name for the EU. If the EU is custom-designed or homemade, indicate so.

9. Provide the model number of the EU. If the EU is custom-designed or homemade, indicate so.

10. Provide the maximum capacity of the EU. For example, a boiler's rated capacity may be modified in units of MMBtu/hr in terms of heat input of natural gas; an assembly line capacity may be in parts produced per day. Capacity should be based on a rated nameplate or as stated in the manufacturer's literature.

11. The date of construction is the month, day, and year in which construction or modification was commenced.

Definitions:

Construction	fabrication, erection, or installation of an affected facility.
Commenced	an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.
Modification	any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted to the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) to the atmosphere not previously emitted.

12. If the EU has been or will be modified, provide the month, day, and year of the most recent or future modification as defined in IDAPA 58.01.01.006.

13. Indicate if emissions from the EU are controlled by air pollution control equipment. If the answer is yes, complete the next section. If the answer is no, go to line 18.

14. Provide the name of the air pollution control equipment (e.g., wet scrubber) and the control equipment's identification number. This identification number should be unique to this air pollution control equipment and should be used consistently throughout this and all other air quality permit applications (e.g., operating permit application) to identify this air pollution control equipment.

15. Provide the date the air pollution control equipment was installed.
16. If the air pollution control equipment has been modified, provide the date of the modification.
17. Provide the name of the manufacturer and the model number for the air pollution control equipment.
18. If this air pollution control equipment controls emissions from more than this EU, provide the identification number(s) of the other EU(s).
19. Indicate if this air pollution control equipment operates on a schedule different from the EU(s) it controls.
20. Indicate if the air pollution control manufacturer guarantees the control efficiency of the control equipment. If the answer is yes, attach the manufacturer's guarantee and label it with the air pollution control equipment identification number. Indicate the control efficiency for the target pollutant(s).
21. If the control efficiency of the air pollution control equipment is not guaranteed, attach the design specifications and any performance data to support the control efficiency stated in part 16. Label the supporting documentation with the air pollution control equipment identification number.
22. Provide the projected actual operating schedule for the emission unit in hours/day, hours/year, or other.
23. Provide the maximum operating schedule for the emission unit in hours/day, hours/year, or other.
24. If you are requesting to have limits placed on this EU, mark "Yes." Then, check the applicable requested limit(s) and provide the limit(s). For example, production limits may be in terms of parts produced per year, material usage limits may be in gallons per day.
25. Please provide the reason you are requesting limits, if any. This helps DEQ and the applicant determine whether the limits are necessary, and if they will accomplish the desired purpose. Provide supporting documentation (calculations, modeling assessment, regulatory review, etc.) for each limit requested.

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
P4 Production, LLC	Soda Springs Facility	029-00001
4. Brief Project Description:	MBACT Analysis and Tier II Permit Update	

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	PHOSPHATE ORE NODULIZING KILN
6.	EU ID Number:	P-1
7.	EU Type:	☐ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	ALLIS CHAMBERS
9.	Model:	
10..	Maximum Capacity:	300 MMBTU/HR
11.	Date of Construction:	1965
12.	Date of Modification (if any):	
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	C-3a, b, c, d - Four Parallel Cyclonic Separators
15. Date of Installation:	1987 16. Date of Modification (if any):
17. Manufacturer and Model Number:	Hydro-Sonics
18. ID(s) of Emission Unit Controlled:	P-1
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency						

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency. See attached MBACT Determination

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	7884 HOURS/YEAR
23.	Maximum Operation:	8760 HOURS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☒ Yes ☐ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☒ Other:	183 LBS/MONTH ON A 12-MONTH ROLLING AVERAGE
25.	Rationale for Requesting the Limit(s):	SEE ATTACHED MBACT DETERMINATION

Instructions for Form EU0

This form provides DEQ with information about an emissions unit. An emissions unit is the equipment or process that generates emissions of regulated air pollutant(s). This form is used by the permit writer to become familiar with the emissions unit (EU). This form is also used by DEQ to identify the control equipment and the emission point (stack or vent) used for the emission unit(s) proposed in this permit application. This form also asks for supporting documents to verify stated control efficiencies and details about the emission point. Additional information may be requested.

1 - 4. Provide the same company name, facility name (if different), facility ID number, and brief project description as on Form CS in the boxes provided. This is useful in case any pages of the application get separated.

5. Provide the name of the emissions unit (EU), such as "Union boiler," etc. A separate EU0 form is required for each emissions unit.

6. Provide the identification (ID) number of the EU. It can be any unique identifier you choose; however, this ID number should be unique to this EU and should be used consistently throughout this application and any other air quality permit application(s) (e.g., operating permit application) to identify this EU.

7. Indicate the type of EU by checking the appropriate box (e.g., a new source to be constructed, an unpermitted existing source (as-built) applying for the first time, or an existing permitted source to be modified). If the EU is being modified, indicate on the form the most recent permit issued for the EU.

8. Provide the manufacturer's name for the EU. If the EU is custom-designed or homemade, indicate so.

9. Provide the model number of the EU. If the EU is custom-designed or homemade, indicate so.

10. Provide the maximum capacity of the EU. For example, a boiler's rated capacity may be modified in units of MMBtu/hr in terms of heat input of natural gas; an assembly line capacity may be in parts produced per day. Capacity should be based on a rated nameplate or as stated in the manufacturer's literature.

11. The date of construction is the month, day, and year in which construction or modification was commenced.

    Definitions:

    Construction fabrication, erection, or installation of an affected facility.

    Commenced an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.

    Modification any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted to the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) to the atmosphere not previously emitted.

12. If the EU has been or will be modified, provide the month, day, and year of the most recent or future modification as defined in IDAPA 58.01.01.006.

13. Indicate if emissions from the EU are controlled by air pollution control equipment. If the answer is yes, complete the next section. If the answer is no, go to line 18.

14. Provide the name of the air pollution control equipment (e.g., wet scrubber) and the control equipment's identification number. This identification number should be unique to this air pollution control equipment and should be used consistently throughout this and all other air quality permit applications (e.g., operating permit application) to identify this air pollution control equipment.

15. Provide the date the air pollution control equipment was installed.

16. If the air pollution control equipment has been modified, provide the date of the modification.

17. Provide the name of the manufacturer and the model number for the air pollution control equipment.

18. If this air pollution control equipment controls emissions from more than this EU, provide the identification number(s) of the other EU(s).

19. Indicate if this air pollution control equipment operates on a schedule different from the EU(s) it controls.

20. Indicate if the air pollution control manufacturer guarantees the control efficiency of the control equipment. If the answer is yes, attach the manufacturer's guarantee and label it with the air pollution control equipment identification number. Indicate the control efficiency for the target pollutant(s).

21. If the control efficiency of the air pollution control equipment is not guaranteed, attach the design specifications and any performance data to support the control efficiency stated in part 16. Label the supporting documentation with the air pollution control equipment identification number.

22. Provide the projected actual operating schedule for the emission unit in hours/day, hours/year, or other.

23. Provide the maximum operating schedule for the emission unit in hours/day, hours/year, or other.

24. If you are requesting to have limits placed on this EU, mark "Yes." Then, check the applicable requested limit(s) and provide the limit(s). For example, production limits may be in terms of parts produced per year, material usage limits may be in gallons per day.

25. Please provide the reason you are requesting limits, if any. This helps DEQ and the applicant determine whether the limits are necessary, and if they will accomplish the desired purpose. Provide supporting documentation (calculations, modeling assessment, regulatory review, etc.) for each limit requested.

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION		
1. Company Name: P4 Production, LLC	2. Facility Name: Soda Springs Facility	3. Facility ID No: 029-00001
4. Brief Project Description:	MBACT Analysis and Tier II Permit Update	

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION	
5. Emissions Unit (EU) Name:	PHOSPHATE ORE NODULIZING KILN
6. EU ID Number:	P-1
7. EU Type:	☐ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8. Manufacturer:	ALLIS CHAMBERS
9. Model:	
10.. Maximum Capacity:	300 MMBTU/HR
11. Date of Construction:	1965
12. Date of Modification (if any):	
13. Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT						
14. Control Equipment Name and ID:	C-4 a, b, c, d - Four Parallel Hydro-sonic scrubbers/demisters					
15. Date of Installation:	1987	16. Date of Modification (if any):				
17. Manufacturer and Model Number:	Hydro-Sonics					
18. ID(s) of Emission Unit Controlled:	P-1					
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No					
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)					
	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency						
21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency. See attached MBACT Determination						

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)	
22. Actual Operation:	7884 HOURS/YEAR
23. Maximum Operation:	8760 HOURS/YEAR

REQUESTED LIMITS	
24. Are you requesting any permit limits?	☒ Yes ☐ No (If Yes, indicate all that apply below)
☐ Operation Hour Limit(s):	
☐ Production Limit(s):	
☐ Material Usage Limit(s):	
☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
☒ Other:	183LBS/MONTH ON A 12-MONTH ROLLING AVERAGE
25. Rationale for Requesting the Limit(s):	SEE ATTACHED MBACT DETERMINATION

Instructions for Form EU0

This form provides DEQ with information about an emissions unit. An emissions unit is the equipment or process that generates emissions of regulated air pollutant(s). This form is used by the permit writer to become familiar with the emissions unit (EU). This form is also used by DEQ to identify the control equipment and the emission point (stack or vent) used for the emission unit(s) proposed in this permit application. This form also asks for supporting documents to verify stated control efficiencies and details about the emission point. Additional information may be requested.

1 - 4. Provide the same company name, facility name (if different), facility ID number, and brief project description as on Form CS in the boxes provided. This is useful in case any pages of the application get separated.

5. Provide the name of the emissions unit (EU), such as "Union boiler," etc. A separate EU0 form is required for each emissions unit.

6. Provide the identification (ID) number of the EU. It can be any unique identifier you choose; however, this ID number should be unique to this EU and should be used consistently throughout this application and any other air quality permit application(s) (e.g., operating permit application) to identify this EU.

7. Indicate the type of EU by checking the appropriate box (e.g., a new source to be constructed, an unpermitted existing source (as-built) applying for the first time, or an existing permitted source to be modified). If the EU is being modified, indicate on the form the most recent permit issued for the EU.

8. Provide the manufacturer's name for the EU. If the EU is custom-designed or homemade, indicate so.

9. Provide the model number of the EU. If the EU is custom-designed or homemade, indicate so.

10. Provide the maximum capacity of the EU. For example, a boiler's rated capacity may be modified in units of MMBtu/hr in terms of heat input of natural gas; an assembly line capacity may be in parts produced per day. Capacity should be based on a rated nameplate or as stated in the manufacturer's literature.

11. The date of construction is the month, day, and year in which construction or modification was commenced.

Definitions:

Construction fabrication, erection, or installation of an affected facility.

Commenced an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.

Modification any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted to the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) to the atmosphere not previously emitted.

12. If the EU has been or will be modified, provide the month, day, and year of the most recent or future modification as defined in IDAPA 58.01.01.006.

13. Indicate if emissions from the EU are controlled by air pollution control equipment. If the answer is yes, complete the next section. If the answer is no, go to line 18.

14. Provide the name of the air pollution control equipment (e.g., wet scrubber) and the control equipment's identification number. This identification number should be unique to this air pollution control equipment and should be used consistently throughout this and all other air quality permit applications (e.g., operating permit application) to identify this air pollution control equipment.

15. Provide the date the air pollution control equipment was installed.

16. If the air pollution control equipment has been modified, provide the date of the modification.

17. Provide the name of the manufacturer and the model number for the air pollution control equipment.

18. If this air pollution control equipment controls emissions from more than this EU, provide the identification number(s) of the other EU(s).

19. Indicate if this air pollution control equipment operates on a schedule different from the EU(s) it controls.

20. Indicate if the air pollution control manufacturer guarantees the control efficiency of the control equipment. If the answer is yes, attach the manufacturer's guarantee and label it with the air pollution control equipment identification number. Indicate the control efficiency for the target pollutant(s).

21. If the control efficiency of the air pollution control equipment is not guaranteed, attach the design specifications and any performance data to support the control efficiency stated in part 16. Label the supporting documentation with the air pollution control equipment identification number.

22. Provide the projected actual operating schedule for the emission unit in hours/day, hours/year, or other.

23. Provide the maximum operating schedule for the emission unit in hours/day, hours/year, or other.

24. If you are requesting to have limits placed on this EU, mark "Yes." Then, check the applicable requested limit(s) and provide the limit(s). For example, production limits may be in terms of parts produced per year, material usage limits may be in gallons per day.

25. Please provide the reason you are requesting limits, if any. This helps DEQ and the applicant determine whether the limits are necessary, and if they will accomplish the desired purpose. Provide supporting documentation (calculations, modeling assessment, regulatory review, etc.) for each limit requested.

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
P4 Production, LLC	Soda Springs Facility	029-00001
4. Brief Project Description:	MBACT Analysis and Tier II Permit Update	

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	PHOSPHATE ORE NODULIZING KILN
6.	EU ID Number:	P-1
7.	EU Type:	☐ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	ALLIS CHAMBERS
9.	Model:	
10..	Maximum Capacity:	300 MMBTU/HR
11.	Date of Construction:	1965
12.	Date of Modification (if any):	
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	C-6 SO2 Scrubbing System (LCDA)
15. Date of Installation:	16. Date of Modification (if any):
17. Manufacturer and Model Number:	Monsanto
18. ID(s) of Emission Unit Controlled:	P-1
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency						

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency. See attached MBACT Determination

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	7884 HOURS/YEAR
23.	Maximum Operation:	8760 HOURS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☒ Yes ☐ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☒ Other:	183 LBS/MONTH ON A 12-MONTH ROLLING AVERAGE BASIS
25.	Rationale for Requesting the Limit(s):	SEE ATTACHED MBACT DETERMINATION

Instructions for Form EU0

This form provides DEQ with information about an emissions unit. An emissions unit is the equipment or process that generates emissions of regulated air pollutant(s). This form is used by the permit writer to become familiar with the emissions unit (EU). This form is also used by DEQ to identify the control equipment and the emission point (stack or vent) used for the emission unit(s) proposed in this permit application. This form also asks for supporting documents to verify stated control efficiencies and details about the emission point. Additional information may be requested.

1 - 4. Provide the same company name, facility name (if different), facility ID number, and brief project description as on Form CS in the boxes provided. This is useful in case any pages of the application get separated.

5. Provide the name of the emissions unit (EU), such as "Union boiler," etc. A separate EU0 form is required for each emissions unit.

6. Provide the identification (ID) number of the EU. It can be any unique identifier you choose; however, this ID number should be unique to this EU and should be used consistently throughout this application and any other air quality permit application(s) (e.g., operating permit application) to identify this EU.

7. Indicate the type of EU by checking the appropriate box (e.g., a new source to be constructed, an unpermitted existing source (as-built) applying for the first time, or an existing permitted source to be modified). If the EU is being modified, indicate on the form the most recent permit issued for the EU.

8. Provide the manufacturer's name for the EU. If the EU is custom-designed or homemade, indicate so.

9. Provide the model number of the EU. If the EU is custom-designed or homemade, indicate so.

10. Provide the maximum capacity of the EU. For example, a boiler's rated capacity may be modified in units of MMBtu/hr in terms of heat input of natural gas; an assembly line capacity may be in parts produced per day. Capacity should be based on a rated nameplate or as stated in the manufacturer's literature.

11. The date of construction is the month, day, and year in which construction or modification was commenced.

Definitions:

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Modification any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted to the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) to the atmosphere not previously emitted.

12. If the EU has been or will be modified, provide the month, day, and year of the most recent or future modification as defined in IDAPA 58.01.01.006.

13. Indicate if emissions from the EU are controlled by air pollution control equipment. If the answer is yes, complete the next section. If the answer is no, go to line 18.

14. Provide the name of the air pollution control equipment (e.g., wet scrubber) and the control equipment's identification number. This identification number should be unique to this air pollution control equipment and should be used consistently throughout this and all other air quality permit applications (e.g., operating permit application) to identify this air pollution control equipment.

15. Provide the date the air pollution control equipment was installed.

16. If the air pollution control equipment has been modified, provide the date of the modification.

17. Provide the name of the manufacturer and the model number for the air pollution control equipment.

18. If this air pollution control equipment controls emissions from more than this EU, provide the identification number(s) of the other EU(s).

19. Indicate if this air pollution control equipment operates on a schedule different from the EU(s) it controls.

20. Indicate if the air pollution control manufacturer guarantees the control efficiency of the control equipment. If the answer is yes, attach the manufacturer's guarantee and label it with the air pollution control equipment identification number. Indicate the control efficiency for the target pollutant(s).

21. If the control efficiency of the air pollution control equipment is not guaranteed, attach the design specifications and any performance data to support the control efficiency stated in part 16. Label the supporting documentation with the air pollution control equipment identification number.

22. Provide the projected actual operating schedule for the emission unit in hours/day, hours/year, or other.

23. Provide the maximum operating schedule for the emission unit in hours/day, hours/year, or other.

24. If you are requesting to have limits placed on this EU, mark "Yes." Then, check the applicable requested limit(s) and provide the limit(s). For example, production limits may be in terms of parts produced per year, material usage limits may be in gallons per day.

25. Please provide the reason you are requesting limits, if any. This helps DEQ and the applicant determine whether the limits are necessary, and if they will accomplish the desired purpose. Provide supporting documentation (calculations, modeling assessment, regulatory review, etc.) for each limit requested.

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline: 1-877-5PERMIT

Cyclone Separator - **Form CYS**
Revision 2
08/28/08

Please see instructions on page 3 before filling out the form.

IDENTIFICATION

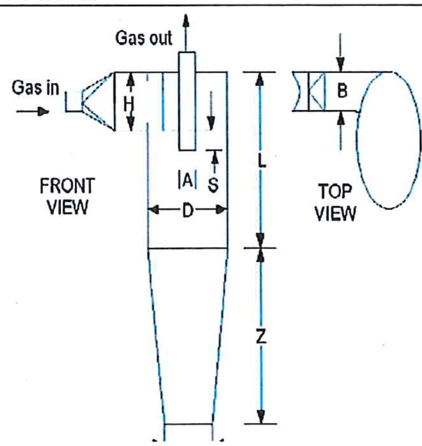
1. Company Name:	P4 Production, LLC	2. Facility Name:	Soda Springs Facility	3. Facility ID No.:	029-00001
4. Brief Project Description:	MBACT Analysis and Tier II Permit Update				

CYCLONE SEPARATOR INFORMATION

Equipment Description

5. Manufacturer:	Hydro-Sonics
6. Model Number:	

7. Dimensions



Give dimensions of cyclone. (See sample diagram above.)

1. B:	in.	5. Z:	in.
2. H:	in.	6. D:	in.
3. S:	in.	7. A:	in.
4. L:	in.	8. J:	in.

8. Particulate Size Distribution Data

Micron range	Particle size distribution weight %	Manufacturer's guaranteed removal efficiency for each micron range
0.5-1.0		
1.0-5.0		
5-10		
10-20		
Over 20		

9. Type of Cyclone	☐ Wet	☐ Dry
10. Type of Cyclone Unit	☐ Single ☐ Dual	☐ Quadruple ☐ Multiclone
11. Blower	Blower horsepower: hp Design flow rate: scfm Draft: ☐ Forced ☐ Induced	

12. Design Criteria	Cyclone configuration: ☐ Positive pressure ☐ Negative pressure
13. Pre-Treatment Device	☐ Cyclone ☐ Knock-out chamber ☐ Precooler ☐ None ☐ Preheater
14. Post-Treatment Device	☐ Baghouse/Cartridge ☐ HEPA ☐ Other:

Process Stream Characteristics	
15. Brief Description of Process	.
16. Flow Data	Gas stream temperature: degrees F Moisture content: grams of water/cubic feet (ft^3) of dry air <u>Pressure drop range</u> High: in. H_2O Low: in. H_2O Dew point temperature of process stream: degrees F Inlet flow rate: ACFM
17. Dust Collection Device	☐ Pneumatic conveyor ☐ Rotary airlock values ☐ Screw conveyors ☐ Closed container ☐ Double dump ☐ Drag conveyor ☐ Manual discharge device: ☐ Slide gate OR ☐ Hinged doors or drawers
18. Operating Schedule	Normal: hours/day days/week weeks/year Maximum: hours/day days/week weeks/year

Instructions for Form CYS

For cyclone separators only, this form may be used *in place of* Form EU0 and control equipment forms.

1 – 4. Provide the same company name, facility name (if different), facility ID number, and brief project description as on Form CS. This is useful in case any pages of the application are separated.

Equipment Description

5 – 14. The information requested should be found in the operations and maintenance manual supplied by the manufacturer of the cyclone separator.

Process Stream Characteristics

15. Include a process flow diagram and engineering drawing of the filter system and the material processed. In the space provided, indicate what equipment is vented to the cyclone and how material is handled and disposed of.

16. Fill in all the requested information about flow rate.

17. Check the appropriate box to indicate the type of dust collection device.

18. Fill in the number of hours per day, days per week, or weeks per year for the normal operating schedule and separately for the maximum operating schedule.

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Scrubber Control Equipment - **Form SCE**
Revision 5
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION									
1. Company Name:	P4 Production, LLC			2. Facility Name:	Soda Springs Facility		3. Facility ID No.:	029-00001	
4. Brief Project Description:	MBACT Analysis and Tier II Permit Update								
EMISSION UNIT ID				SCRUBBER					
5.	6.	7.	8.	9.	10.	11.	12.	13	14.
Emission Unit	EU ID No.	CE ID No.	Stack ID No.	Manufacturer Name	Model No.	Type	Dimensions In Feet (Ht x Dia x L)	Water Flow (gpm)	Pressure Drop (in H_2O)
PHOSPHATE ORE NODULIZING KILN	P-1	C-2		Monsanto		spray tower	30' diameter x 60' tall	3200	4.86
PHOSPHATE ORE NODULIZING KILN	P-1	C-6		Hydro-Sonics		scrubbing system		≥ 900	≥ 40

Instructions for Form SCE

This information is used by DEQ to identify the scrubber control equipment in this permit application.

1 – 4. Provide the same company name, facility name (if different), facility ID number, and brief project description as on Form CS. This is useful in case any pages of the application are separated.

Provide the following:

5. The name of the emissions unit, exactly the same as it appears on Form EU0.
6. The emissions unit ID No., exactly the same as it appears on Form EU0.
7. Control equipment ID No., exactly the same as it appears on Form EU0.
8. Stack ID No.
9. Name of the scrubber manufacturer.
10. Model number of the scrubber.
11. Type of scrubber (e.g., spray chamber, venturi, packed bed, etc.).
12. Dimensions in feet (height x diameter x length)
13. Scrubber water flow to scrubber (gallons per minute).
14. Pressure drop across scrubber.

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Venturi Scrubber Control Equipment - **Form VSCE**
Revision 2
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION										
1. Company Name:	P4 Production, LLC			2. Facility Name:	Soda Springs Facility			3. Facility ID No.:	029-00001	
4. Brief Project Description:	MBACT Analysis and Tier II Permit Update									
EMISSION UNIT ID				**SCRUBBER**						
5.	6.	7.	8.	9.	10.	11.	12.	13	14.	15.
Emission Unit	EU ID No.	CE ID No.	Stack ID No.	Manufacturer Name	Model No.	Efficiency (PM_{10}@70%, SO_2@50%, etc.)	Basis for Efficiency (i.e., guarantee, source test, etc.)	Design Scrubbing Liquid Flow (gpm)	Design Pressure Drop (in H_2O)	Design pH (for acid gas control)
PHOSPHATE ORE NODULIZING KILN	P-1	C-4		Hydro-Sonics		Hg@35%	source test and material analysis	>900	40	6.7

Describe the maintenance required to assure the scrubber operates as designed (i.e. frequency of inspection, nozzle inspection, nozzle cleaning, etc.). (Provide an attachment if necessary.) Flow and pressure drop are monitored continuously by the process control system and every 4 hours by the operator. Both flow and pressure drop are calibrated every 6 months. If flow or pressure drop falls outside permitted CAM limits, field inspections and maintenance activity is initiated.

Instructions for Form VSCE

This information is used by DEQ to identify the scrubber control equipment in this permit application.

1 – 4. Provide the same company name, facility name (if different), facility ID number, and brief project description as on Form CS. This is useful in case any pages of the application are separated.

Provide the following:

5. The name of the emissions unit, exactly the same as it appears on Form EU0.
6. The emissions unit ID No., exactly the same as it appears on Form EU0.
7. Control equipment ID No., exactly the same as it appears on Form EU0.
8. Stack ID No.
9. Name of the scrubber manufacturer.
10. Model number of the scrubber.
11. Give scrubber control efficiency and pollutant controlled (i.e., PM_{10}@70%, SO_2@50%, etc.). For particulate matter, give efficiency for PM_{10} and for total PM.
12. The basis for stated efficiency must be documented. Attach supporting documentation such as manufacturer guarantees, source tests, design calculations, or other means of substantiating control efficiency.
13. Give the design scrubbing media flowrate in gpm to achieve stated control efficiency.*
14. Give the design pressure drop in inches of water column to achieve stated control efficiency.*
15. For acid gas scrubbers, give the design scrubbing liquid pH.*

* These parameters will become operating standards in a permit.

STATE OF IDAHO
DEPARTMENT OF
ENVIRONMENTAL QUALITY

Version 1, August 2010

Facility Wide Potential to Emit Emission Inventory

Application Template and Instructions

For new stationary sources provide the facility's potential to emit for all NSR Regulated Air Pollutants. The potential to emit provided here must match the emissions rates which are requested to be permitted.

For modifications to existing facilities (including the addition of new emissions units), if the existing facility classification is in question an existing facility wide potential to emit emission inventory will be required to be submitted[1]. Contact DEQ to determine if a facility wide emission inventory for the existing facility is required.

All emissions inventories must be submitted with thorough documentation. The emission inventories will be subjected to technical review. Therefore, prepare your application with sufficient documentation so that the public and DEQ can verify the validity of the emission estimates. **Applications submitted without sufficient documentation are incomplete. Follow the instructions provided on page 2; do not proceed until you have read the instructions.**

Applicants must use the Potential to Emit Summary table provided below.

Table 1. POTENTIAL TO EMIT FOR MERCURY

Emissions Unit	Mercury	Mercury	NSR Pollutant[a]	NSR Pollutant[a]	NSR Pollutant[a]	NSR Pollutant[a]
	Lbs/yr	Lbs/yr	T/yr	T/yr	T/yr	T/yr
Point Sources						
Facility-Wide Hg Emission Units	See Attached Table 2	1082.95 lbs	-	-	-	-
Fugitive Sources *{For listed source categories only, see item 3 below in the instructions}*						
Facility-Wide Fugitive Hg	See Attachment Table 2	0.59 lbs	-	-	-	-
Totals		**1083.54 lbs**	-	-	-	-

a) NSR Regulated air Pollutants are defined[2] as: Particulate Matter (PM, PM-10, PM-2.5), Carbon Monoxide, Lead, Nitrogen Dioxide, Ozone (VOC), Sulfur Dioxide, CO_2e[3], Green House Gases (GHG) mass, all pollutants regulated by NSPS (40 CFR 60)(i.e. TRS, fluoride, sulfuric acid mist) & Class I & Class II Ozone Depleting Substances (40 CFR 82)(i.e. CFC, HCFC, Halon, etc.)

Applicants are encouraged to call DEQ's Air Quality Permit Hotline (1-877-573-7648) to ask questions as they prepare the application.

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[1] The applicant must determine if the existing facility is a major facility. If the facility is an existing PSD major facility and changes are being made to the facility the major modification test must be conducted.

[2] 40 CFR 52.21(b)(50), as incorporated by reference at IDAPA 58.01.01.107.03.d

[3] Multiply each green house gas (GHG) by the global warming potential (GWP) listed at 40 CFR 98, Table A- 1 of Subpart A then sum all values to determine CO_2e (GHGs are carbon dioxide, nitrous oxide, methane, hydrofluorcarbons, perfluorcarbons, sulfur hexafluoride). Be sure to show all calculations as described in the instructions.

Emission Inventory Instructions:

1. Use the same emission unit name throughout the application (i.e. in air pollution control equipment forms and for modeling purposes).

2. The application must **show in detail all calculations** used to develop the PTE summary and include:

- Electronic copies of any spreadsheets used to estimate emissions. If a spreadsheet is used submit an electronic copy of the spread sheet (i.e. Excel File).
- Documentation of all calculations conducted by hand (i.e. show all calculations).
- Clear statements on all assumptions relied upon in estimating emissions.
- Documentation of the emissions factors used to estimate emissions. If the emissions factor documentation is readily available to DEQ, such as an EPA AP-42 emissions factor, a simple reference to the emissions factor suffices. If the emissions factor documentation is not readily available to DEQ the applicant must submit the documentation with the application; ask DEQ if you are uncertain. **Applications without sufficient documentation are incomplete.** Documentation may consist of manufacturer guarantees, research conducted by trade organizations, published emission factors, and source test results. **If there are multiple factors for a given operation, note why the factor used is the most representative.**
- Copies of manufacturer guarantees upon which emission inventories are based.
- The best available emission information (see DEQ's Guidance on Emission Data Hierarchy).
- If source tests are used as the basis for emissions estimates the source test report must be submitted. If the source test report is on file with DEQ provide the date of the source test was submitted along with the name of the facility and the emission unit that was tested. Source data from similar emissions units may be considered reliable provided it is clearly described why the sources are similar. Similar sources are those that the applicant has shown serve a similar function, use similar raw materials, and have similar processing rates.

3. Fugitive emissions of NSR regulated air pollutants from the source categories listed below must be included in the emission inventory.

Listed Source Categories for Inclusion of Fugitive Emissions

- Coal cleaning plants (with thermal dryers)
- Kraft pulp mills
- Portland cement plants
- Primary zinc smelters
- Iron and steel mills
- Primary aluminum ore reduction plants
- Primary copper smelters
- Municipal incinerators -250 T/day of refuse
- Hydrofluoric, sulfuric, or nitric acid plants
- Petroleum refineries
- Lime plants
- Phosphate rock processing plants
- Coke oven batteries
- Sulfur recovery plants
- Carbon black plants (furnace process)
- Primary lead smelters
- Fuel conversion plants
- Sintering plants
- Secondary metal production plants
- Chemical process plants (excluding ethanol plants by natural fermentation).
- Fossil-fuel fired boilers totaling more than 250 MMBtu/hr
- Petroleum storage and transfer units with total capacity of 300,000 barrels
- Taconite ore processing plants
- Glass fiber processing plants
- Charcoal production plants
- Fossil fuel-fired steam electric plants greater than 250 MMBtu/hr)
- Categories regulated by NSPS or NESHAP prior to 8/7/80

Point Source Emission Calculations

Table 2 - Determination of Potential Hg Emissions for P4 Productions, Soda Springs, Idaho

ID	Process Area	Emission Source	2006 Mercury Emissions (lb/yr)	2007 Mercury Emissions (lb/yr)	2008 Mercury Emissions (lb/yr)	2009 Mercury Emissions (lb/yr)	2010 Mercury Emissions (lb/yr)	2011 Mercury Emissions (lb/yr)	2012 Mercury Emissions (lb/yr)	2013 Mercury Emissions (lb/yr)	2014 Mercury Emissions (lb/yr)	Average (2006 - 2014) Hg Emissions (lb/yr)	Potential Emission Estimate (lb/yr)
310	Kiln Hydrosonics	Kiln Hydrosonics Stacks (Total)	6.56E+02	4.87E+02	6.09E+02	5.11E+02	5.84E+02	6.16E+02	6.02E+02	5.89E+02	8.58E+02	6.12E+02	1078
409	Nodule Crushing and Screening Scrubber	Nodule Crushing and Screening Scrubber Stack	2.58E+00	1.80E+00	2.15E+00	1.59E+00	2.11E+00	2.28E+00	1.52E+00	1.40E-01	1.29E-01	1.59E+00	2.80
314	Cooler Spray Tower	Cooler Spray Tower Stack	2.52E-01	2.61E-01	7.53E-01	5.19E-01	6.09E-01	6.49E-01	6.31E-01	6.16E-01	6.39E-01	5.47E-01	9.64E-01
546	#7 THFC	#7 THFC Stack	2.51E-02	2.55E-02	6.14E-02	4.29E-02	6.64E-02	6.67E-02	1.72E-02	1.92E-02	2.11E-02	3.84E-02	6.76E-02
594	#9 THFC	#9 THFC Stack	2.40E-02	3.80E-04	7.63E-03	5.55E-03	8.35E-03	8.38E-03	8.12E-03	8.55E-03	8.52E-03	8.83E-03	1.56E-02
570	#8 THFC	#8 THFC Stack	2.26E-02	1.82E-02	5.53E-02	4.58E-02	4.89E-02	5.71E-02	3.23E-02	3.34E-02	3.20E-02	3.84E-02	6.76E-02
429	SDM Bin Vent	SDM Bin Vent Stack	2.49E-04	2.49E-04	1.51E-04	1.50E-04	1.50E-04	1.50E-04	1.50E-04	1.47E-04	1.49E-04	1.72E-04	3.02E-04
119	Coke Handling Baghouse (C&Q)	Coke Handling Baghouse Stack	1.37E-04	1.41E-04	1.63E-05	1.24E-05	1.75E-05	1.82E-05	1.83E-05	1.89E-05	1.77E-05	4.41E-05	7.76E-05
403	Nodule Reclaim Baghouse	Nodule Reclaim Baghouse Stack	7.02E-05	7.32E-05	7.37E-05	7.33E-05	7.40E-05	7.45E-05	2.54E-03	7.27E-05	6.89E-05	3.47E-04	6.11E-04
501	Scaleroom Baghouse	Scaleroom Baghouse Stack	6.57E-05	6.25E-05	6.41E-05	4.82E-05	6.59E-05	6.88E-05	6.70E-05	6.93E-05	6.90E-05	6.45E-05	1.14E-04
524	Main Furnace Baghouse	Main Furnace Baghouse Stack	2.01E-05	1.92E-05	2.32E-05	1.74E-05	2.38E-05	2.49E-05	2.42E-05	2.50E-05	2.49E-05	2.25E-05	3.96E-05
592	No. 9 CO Dust Baghouse	No. 9 CO Dust Baghouse Stack	1.78E-05	1.67E-05	1.64E-06	1.20E-06	1.80E-06	1.81E-06	1.75E-06	1.84E-06	1.84E-06	5.15E-06	9.07E-06
568	No. 8 CO Dust Baghouse	No. 8 CO Dust Baghouse Stack	1.52E-05	1.51E-05	2.57E-06	2.12E-06	2.27E-06	2.65E-06	2.59E-06	2.68E-06	2.57E-06	5.31E-06	9.34E-06
108	Dryer BH	Dryer Baghouse Stack	1.03E-05	1.24E-05	1.39E-05	1.05E-05	1.40E-05	1.45E-05	1.30E-05	4.40E-05	1.35E-05	1.62E-05	2.86E-05
603	#309 Coke Fines Bin Vent	#309 Coke Fines Bin Vent Stack	7.83E-06	3.19E-06	1.77E-06	1.81E-06	4.10E-06	4.36E-06	1.15E-06	3.78E-07	0.00E+00	2.73E-06	4.81E-06
544	No. 7 CO Dust Baghouse	No. 7 CO Dust Baghouse Stack	7.73E-06	7.29E-06	1.09E-06	7.62E-07	1.18E-06	1.18E-06	1.04E-06	1.16E-06	1.28E-06	2.52E-06	4.44E-06
592	#9 CO Dust Collection Bypass	#9 CO Dust Collection Bypass Stack	5.14E-06	2.59E-06	3.77E-07	1.55E-06	7.90E-07	2.93E-07	3.44E-07	2.10E-06	2.65E-06	1.76E-06	3.10E-06
568	#8 CO Dust Collection Bypass	#8 CO Dust Collection Bypass Stack	5.06E-06	6.19E-06	3.95E-07	5.02E-06	8.41E-08	1.10E-07	2.96E-06	2.69E-06	2.48E-06	2.78E-06	4.89E-06
555	#305 Coke Fines Bin Vent	#305 Coke Fines Bin Vent Stack	3.67E-06	5.38E-07	5.23E-08	2.02E-07	1.20E-06	2.13E-06	5.46E-07	2.90E-07	1.60E-08	9.60E-07	1.69E-06
579	#307 Coke Fines Bin Vent	#307 Coke Fines Bin Vent Stack	2.90E-06	1.40E-06	4.22E-07	8.29E-07	1.26E-06	2.67E-06	2.09E-07	1.50E-07	4.62E-09	1.09E-06	1.93E-06
544	#7 CO Dust Collection Bypass	#7 CO Dust Collection Bypass Stack	2.83E-06	1.81E-06	1.26E-07	6.55E-07	5.24E-08	5.68E-08	8.74E-08	1.19E-06	5.96E-07	8.22E-07	1.45E-06
112	105 Baghouse	105 Baghouse Stack	1.98E-06	4.89E-06	6.96E-06	5.03E-06	7.05E-06	7.48E-06	7.40E-06	7.56E-06	7.69E-06	6.23E-06	1.10E-05
554	#304 Coke Fines Bin Vent	#304 Coke Fines Bin Vent Stack	6.86E-07	1.15E-07	3.06E-07	1.58E-07	5.90E-07	9.88E-07	1.87E-07	3.80E-09	0.00E+00	3.37E-07	5.94E-07
602	#308 Coke Fines Bin Vent	#308 Coke Fines Bin Vent Stack	6.27E-07	3.03E-07	4.99E-07	5.59E-07	7.59E-07	2.20E-06	5.33E-07	1.44E-07	3.14E-09	6.25E-07	1.10E-06
202	104 Baghouse	104 Baghouse Stack	6.02E-07	6.90E-07	7.29E-04	8.04E-04	8.05E-04	6.75E-04	8.04E-04	7.89E-04	8.05E-04	6.01E-04	1.06E-03
578	#306 Coke Fines Bin Vent	#306 Coke Fines Bin Vent Stack	3.05E-07	4.11E-07	3.40E-07	4.82E-07	6.05E-07	1.27E-06	2.45E-07	7.92E-08	4.46E-09	4.16E-07	7.32E-07
101	Coke Bunker Baghouse	Coke Bunker Baghouse Stack	1.08E-07	4.57E-08	2.60E-09	4.44E-08	5.06E-08	3.14E-08	8.80E-08	2.03E-09	5.42E-09	4.20E-08	7.39E-08
134.2	Bulk Storage Bin Baghouse (Coke Fines BH	Bulk Storage Bin Baghouse Stack	8.88E-09	2.72E-09	1.98E-09	2.14E-09	9.70E-09	1.56E-08	2.50E-09	9.04E-10	1.03E-10	4.94E-09	8.70E-09
121	Vactor Truck Vent - C&Q BH Unloading	Vactor Truck Vent Stack	7.12E-09	7.12E-09	7.12E-09	7.12E-09	7.12E-09	7.12E-09	7.12E-09	7.12E-09	7.12E-09	7.12E-09	1.25E-08
523	Vactor Truck Vent - Scaleroom BH Unloadin	Vactor Truck Vent Stack	4.74E-09	4.74E-09	2.37E-09	2.37E-09	2.37E-09	2.37E-09	2.37E-09	2.37E-09	2.37E-09	2.90E-09	5.10E-09
523	Vactor Truck Vent - Scaleroom Vacuum Sys	Vactor Truck Vent Stack	4.74E-09	4.74E-09	2.37E-09	2.37E-09	2.37E-09	2.37E-09	2.37E-09	2.37E-09	2.37E-09	2.90E-09	5.10E-09
102	Vactor Truck Vent - Coke Bunker BH Unloac	Vactor Truck Vent Stack	4.34E-09	4.34E-09	4.82E-10	4.82E-10	4.82E-10	4.82E-10	4.82E-10	4.82E-10	4.82E-10	1.34E-09	2.36E-09
109	Vactor Truck Vent - Dryer BH Unloading	Vactor Truck Vent Stack	2.67E-09	2.67E-09	2.22E-09	2.22E-09	2.22E-09	2.22E-09	2.22E-09	2.22E-09	2.22E-09	2.32E-09	4.09E-09
116	Vactor Truck Vent - 105 BH Unloading	Vactor Truck Vent Stack	2.31E-09	2.31E-09	2.31E-09	2.31E-09	2.31E-09	2.31E-09	2.31E-09	2.31E-09	2.31E-09	2.31E-09	4.07E-09
530	Vactor Truck Vent - Main Stocking BH Unloa	Vactor Truck Vent Stack	2.15E-09	2.15E-09	2.15E-09	2.15E-09	2.15E-09	2.15E-09	2.15E-09	2.15E-09	2.15E-09	2.15E-09	3.78E-09
610	Vactor Truck Vent - Dust Container Unloadi	Vactor Truck Vent Stack	2.07E-09	2.07E-09	2.07E-09	2.07E-09	2.07E-09	2.07E-09	2.07E-09	2.07E-09	2.07E-09	2.07E-09	3.65E-09
855	Vactor Truck Vent - Lab BH Unloading	Vactor Truck Vent Stack	3.42E-10	3.42E-10	3.42E-10	3.42E-10	3.42E-10	3.42E-10	3.42E-10	3.42E-10	3.42E-10	3.42E-10	6.02E-10
1110	Thermal Oxidizer	Thermal Oxidizer Stacks									5.87E-01	5.87E-01	1.03E+00
		Total Point Sources:	659.02	488.91	612.23	512.91	586.69	619.14	603.79	590.12	859.04	614.58	1082.95
	Fugitive Sources	Total Fugitive Sources:	0.0374	0.0343	0.0356	0.0324	0.0383	0.1240	1.0720	0.9296	0.702	0.3340	5.88E-01
		Total Point and Fugitive											1083.54

Note 1 - Potential Emissions have been determined by increasing the average actual emission rate for each point source by the ratio of Kiln PTE/Kiln Average Actual Hg Emissions

Note 2 - Hg Emissions of 1078 lbs per year from the Nodulizing Kiln determined as follows:

Mercury emission test results:

Gaseous mercury: 0.1127 lb/hr (2014 stack test)

Ore throughput during 2014 gaseous test: 241.326 ton/hr

Particulate mercury: 0.00616 lb/hr (2014 stack test)

Ore throughput during 2014 particulate test: 241.326 ton/hr

Gaseous Hg emission factor:

$(0.1127 \text{ lb/hr})/(241.33 \text{ ton/hr}) = 4.67 \times 10^{-4}$ lb/ton

Particulate Hg emission factor:

$(0.00616 \text{ lb/hr})/(241.33 \text{ ton/hr}) = 2.55 \times 10^{-5}$ lb/ton

Overall Hg emission factor:

4.67×10^{-4} lb/ton + 2.55×10^{-5} lb/ton = 4.92×10^{-4} lb/ton

Maximum ore throughput:

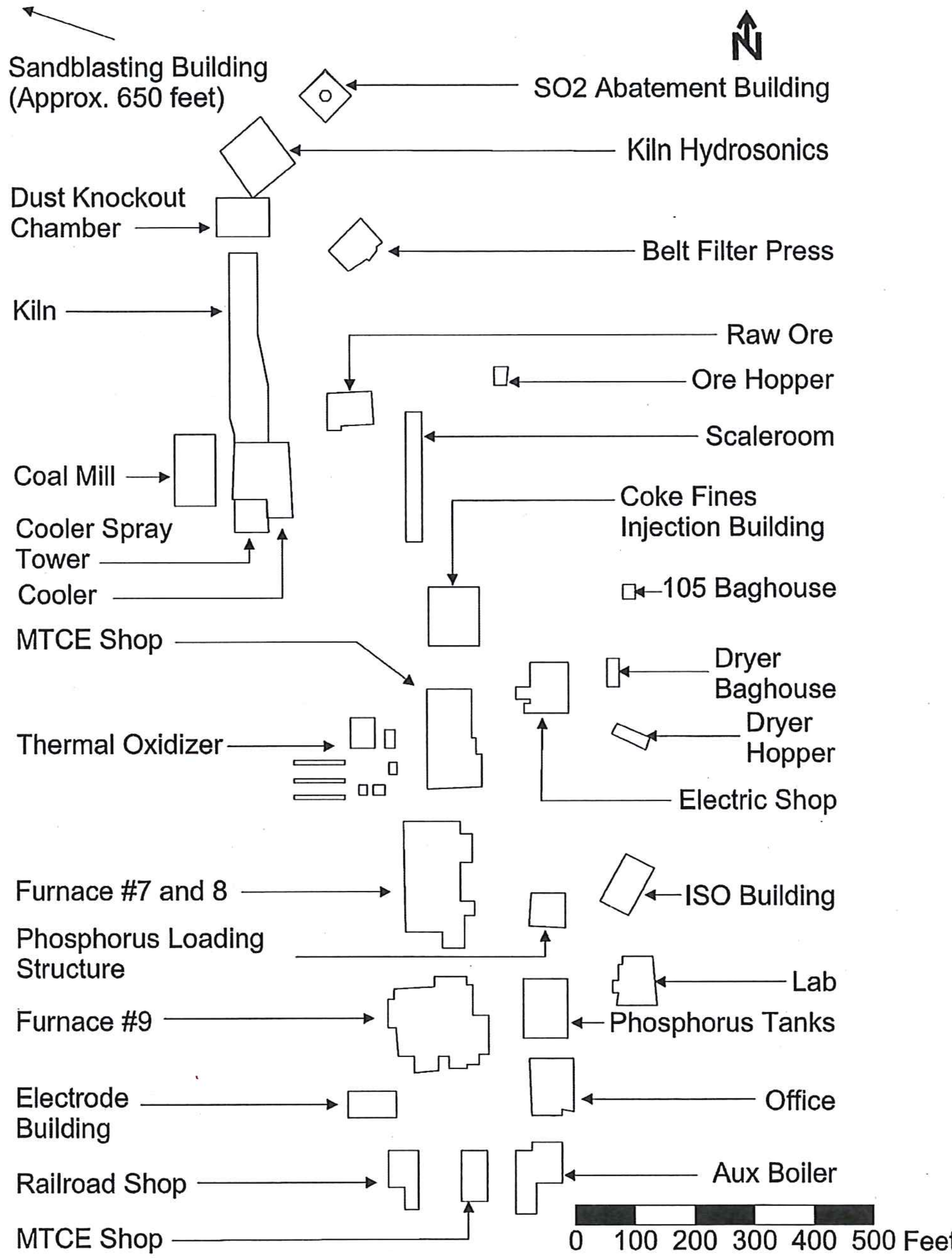
(249.9 ton/hr) x (8,760 hr/yr) = 2,189,124 ton/yr

Maximum emissions (Potential to Emit):

(4.92 x 10-4 lb/ton) x (2,189,124 ton/yr) =1078 lb/yr

Mercury Compounds Air Emissions Summary

Year	Fugitive Source Emissions (lb/year)	Point Source Emissions (lb/year)	Total Air Emissions (lb/year)	Total Kiln Throughput (tons/year)
2006	0.037	659.0	659.1	1,649,174
2007	0.034	488.9	488.9	1,473,575
2008	0.036	612.2	612.3	1,741,341
2009	0.032	512.9	512.9	1,459,788
2010	0.038	586.7	586.7	1,668,866
2011	0.124	619.1	619.3	1,760,985
2012	1.072	603.8	604.9	1,719,533
2013	0.930	590.1	591.1	1,684,462
2014	0.702	858.5	859.2	1,737,769



P4 Production, LLC Soda Springs Facility Plot Plan

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

AIR PERMIT APPLICATION

Revision 6
10/7/09

For each box in the table below, CTRL+click on the blue underlined text for instructions and information.

IDENTIFICATION	
1. Company Name: P4 Production, LLC	2. Facility Name: Soda Springs Facility
3. Brief Project Description: MBACT Analysis and Tier II Update	
APPLICABILITY DETERMINATION	
4. List applicable subparts of the New Source Performance Standards (NSPS) (40 CFR part 60). Examples of NSPS affected emissions units include internal combustion engines, boilers, turbines, etc. The applicant must thoroughly review the list of affected emissions units.	List of applicable subpart(s): ☑ Not Applicable
5. List applicable subpart(s) of the National Emission Standards for Hazardous Air Pollutants (NESHAP) found in 40 CFR part 61 and 40 CFR part 63. Examples of affected emission units include solvent cleaning operations, industrial cooling towers, paint stripping and miscellaneous surface coating. EPA has a web page dedicated to NESHAP that should be useful to applicants.	List of applicable subpart(s): ☑ Not Applicable
6. For each subpart identified above, conduct a complete a regulatory analysis using the instructions and referencing the example provided on the following pages. **Note** - Regulatory reviews must be submitted with sufficient detail so that DEQ can verify applicability and document in legal terms why the regulation applies. Regulatory reviews that are submitted with insufficient detail will be determined incomplete.	☐ A detailed regulatory review is provided (Follow instructions and example). ☐ DEQ has already been provided a detailed regulatory review. Give a reference to the document including the date.

IF YOU ARE UNSURE HOW TO ANSWER ANY OF THESE QUESTIONS, CALL THE AIR PERMIT HOTLINE AT 1-877-5PERMIT

It is emphasized that it is the applicant's responsibility to satisfy all technical and regulatory requirements, and that DEQ will help the applicant understand what those requirements are prior to the application being submitted but that DEQ will not perform the required technical or regulatory analysis on the applicant's behalf.

Instructions for Form FRA

Item 4 & 5. It is important that facilities review the most recent federal regulations when submitting their permit application to DEQ. Current federal regulations can be found at the following Web site: http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?&c=ecfr&tpl=/ecfrbrowse/Title40/40tab_02.tpl.

Item 6. For each applicable subpart identified under items 4-5 conduct a complete regulatory analysis. The facility must follow the procedure given below or obtain permission from DEQ to provide the necessary information using an alternative procedure:

1. Retrieve a TEXT or PDF copy of the applicable federal regulation subpart(s) online at http://www.gpoaccess.gov/cfr/retrieve.html

2. Copy and paste the regulation(s) into your DEQ air permit application.

3. Highlight or underline sections in the regulation(s) that are applicable to the source(s).

4. Under each section of the subpart, explain why the source is subject to the section, or why the source is not subject to the section. When providing the explanation use a different font than the regulation (i.e. ***bold, italic***) so that it is easy for the reader to determine the text that the applicant has provided. An example NSPS regulatory analysis is attached. The applicant must provide all necessary information needed to determine applicability. If information is lacking or the analysis is incomplete the application will be determined incomplete.

   EPA provides a web site dedicated to NSPS/NESHAP applicability determinations that may be useful to applicants. Follow this link to the applicability determination index Clean Air Act Applicability Determination Index - Compliance Monitoring - EPA. Another useful source of information is the preamble to the regulation which is published in the Federal Register on the date the regulation was promulgated. Federal Registers may be found online at Federal Register: Main Page. The date the regulation was published in the Federal Register is included in the footnotes of the regulation.

5. DEQ will assist in identifying the applicable requirements that the applicant must include in the application but will not perform the required technical or regulatory analysis on the applicant's behalf. Applicants should contact the Air Quality Permit Hotline (1-877-573-7648) to discuss NSPS/NESHAP regulatory analysis requirements or to schedule a meeting.

6. It also benefits facilities to document a non-applicability determination on federal air regulations which appear to apply to the facility but actually do not. A non-applicability determination will avoid future confusion and expedite the air permit application review. If you conduct an applicability determination and find that your activity is not NSPS or NESHAP affected facility an analysis should be submitted using the methods described above.

7. **It is not sufficient to simply provide a copy of the NSPS or NESHAP. The applicant must address each section of the regulation as described above and as shown in the example that is provided.**

EXAMPLE OF A NSPS REGULATORY ANALYSIS

[Title 40, Volume 6]
[Revised as of July 1, 2008]
From the U.S. Government Printing Office via GPO Access
[CITE: 40CFR60]

TITLE 40--PROTECTION OF ENVIRONMENT

CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY (CONTINUED)

PART 60_STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES--
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Subpart H_Standards of Performance for Sulfuric Acid Plants

Sec.60.80 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to each sulfuric acid production unit, which is the affected facility.
(b) Any facility under paragraph (a) of this section that commences construction or modification after August 17, 1971, is subject to the requirements of this subpart.

ACME Chemicals, Inc. is proposing to construct after August 17, 1971 a sulfuric acid plant which burns elemental sulfur as defined by 40 CFR 60.81(a). ACME is therefore affected by this subpart.

(Be sure to use the terms of the regulation to describe applicability; usually applicability is determined based on a specific date, definition of an affected facility, and rated input capacity. All of the applicability criteria must be addressed by the applicant.)

Note - if a determination of non-applicability is being submitted it is not necessary to address the remaining non-applicable regulatory sections. Be sure to provide the applicability determination in terms of the regulation (i.e. construction/modification date, rated input capacity, definition of affected facility).

Sec.60.81 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.
(a) Sulfuric acid production unit means any facility producing sulfuric acid by the contact process by burning elemental sulfur, alkylation acid, hydrogen sulfide, organic sulfides and mercaptans, or acid sludge, but does not include facilities where conversion to sulfuric acid is utilized primarily as a means of preventing emissions to the atmosphere of sulfur dioxide or other sulfur compounds.
(b) Acid mist means sulfuric acid mist, as measured by Method 8 of appendix A to this part or an equivalent or alternative method.

ACME Chemicals, Inc. has read and understands these definitions and used them in providing this regulatory analysis.

Sec.60.82 Standard for sulfur dioxide.

(a) On and after the date on which the performance test required to be conducted by Sec.60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of 2 kg per metric ton of acid produced (4 lb per ton), the production being expressed as 100 percent H2/SO4/.

ACME Chemicals, Inc. is subject to this standard and has provided a documented emission inventory (or manufacturer guarantee) which shows compliance.

Sec.60.83 Standard for acid mist.

(a) On and after the date on which the performance test required to be conducted by Sec.60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which:

(1) Contain acid mist, expressed as H2/SO4/, in excess of 0.075 kg per metric ton of acid produced (0.15 lb per ton), the production being expressed as 100 percent H2/SO4/.

ACME Chemicals, Inc. is subject to this standard and has provided a documented emission inventory (or manufacturer guarantee) which shows compliance.

(2) Exhibit 10 percent opacity, or greater.

ACME Chemicals, Inc. understands that this will become a permit condition and has supplied a manufacturer guarantee that the sulfuric acid plant will comply with this standard.

Sec.60.84 Emission monitoring.

(a) A continuous monitoring system for the measurement of sulfur dioxide shall be installed, calibrated, maintained, and operated by the owner or operator. The pollutant gas used to prepare calibration gas mixtures under Performance Specification 2 and for calibration checks under Sec.60.13(d), shall be sulfur dioxide (SO2/). Method 8 shall be used for conducting monitoring system performance evaluations under Sec.60.13(c) except that only the sulfur dioxide portion of the Method 8 results shall be used. The span value shall be set at 1000 ppm of sulfur dioxide.

(b) The owner or operator shall establish a conversion factor for the purpose of converting monitoring data into units of the applicable standard (kg/metric ton, lb/ton). The conversion factor shall be determined, as a minimum, three times daily by measuring the concentration of sulfur dioxide entering the converter using suitable methods (e.g., the Reich test, National Air Pollution Control Administration Publication No. 999-AP-13) and calculating the appropriate conversion factor for each eight-hour period as follows:

CF=k[(1.000-0.015r)/(r-s)]

where:

CF=conversion factor (kg/metric ton per ppm, lb/ton per ppm).
k=constant derived from material balance. For determining CF in metric units, k=0.0653. For determining CF in English units, k=0.1306.
r=percentage of sulfur dioxide by volume entering the gas converter. Appropriate corrections must be made for air injection plants subject to the Administrator's approval.
s=percentage of sulfur dioxide by volume in the emissions to the atmosphere determined by the continuous monitoring system required under paragraph (a) of this section.

(c) The owner or operator shall record all conversion factors and values under paragraph (b) of this section from which they were computed (i.e., CF, r, and s).

ACME Chemicals, Inc. is not proposing to utilize Sections 60.84(a)-(c)listed above to monitor emissions. Instead ACME Chemicals is utilizing 40 CFR 60.84(d) listed below to monitor emissions of sulfur dioxide.

(d) Alternatively, a source that processes elemental sulfur or an ore that contains elemental sulfur and uses air to supply oxygen may use the following continuous emission monitoring approach and calculation procedures in determining SO2/ emission rates in terms of the standard. This procedure is not required, but is an alternative that would alleviate problems encountered in the measurement of gas velocities or production rate. Continuous emission monitoring systems for measuring SO2/, O2/, and CO2/ (if required) shall be installed, calibrated, maintained, and operated by the owner or operator and subjected to the certification procedures in Performance Specifications 2 and 3. The calibration procedure and span value for the SO2/ monitor shall be as specified in paragraph (b) of this section. The span value for CO2/ (if required) shall be 10 percent and for O2/ shall be 20.9 percent (air). A conversion factor based on process rate data is not necessary. Calculate the SO2/ emission rate as follows:

Es/=(Cs/ S)/[0.265-(0.126 %O2/)-(A %CO2/)]

where:

Es/=emission rate of SO2/, kg/metric ton (lb/ton) of 100 percent of H2/SO4/ produced.
Cs/=concentration of SO2/, kg/dscm (lb/dscf).
S=acid production rate factor, 368 dscm/metric ton (11,800 dscf/ton) of 100 percent H2/SO4/ produced.
%O2/=oxygen concentration, percent dry basis.
A=auxiliary fuel factor,
=0.00 for no fuel.
=0.0226 for methane.
=0.0217 for natural gas.
=0.0196 for propane.
=0.0172 for No 2 oil.
=0.0161 for No 6 oil.
=0.0148 for coal.
=0.0126 for coke.
%CO2/= carbon dioxide concentration, percent dry basis.

Note: It is necessary in some cases to convert measured concentration units to other units for these calculations:

Use the following table for such conversions:

From--	To--	Multiply by--
g/scm............................	kg/scm.............	10-3
mg/scm...........................	kg/scm.............	10-6
ppm (SO2)........................	kg/scm.............	2.660x10-6
ppm (SO2)........................	lb/scf.............	1.660x10-7

ACME Chemicals, Inc. has elected to use the monitoring requirements of the preceding section.

(e) For the purpose of reports under Sec.60.7(c), periods of excess emissions shall be all three-hour periods (or the arithmetic average of three consecutive one-hour periods) during which the integrated average sulfur dioxide emissions exceed the applicable standards under Sec.60.82.

ACME acknowledges that this section applies to the sulfuric acid plant.

Sec.60.85 Test methods and procedures.

(a) In conducting the performance tests required in Sec.60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in Sec.60.8(b). Acceptable alternative methods and procedures are given in paragraph (c) of this section.

(b) The owner or operator shall determine compliance with the SO2/ acid mist, and visible emission standards in Sec. Sec. 60.82 and 60.83 as follows:

(1) The emission rate (E) of acid mist or SO2/ shall be computed for each run using the following equation:

E=(CQsd/)/(PK)

where:

E=emission rate of acid mist or SO2/ kg/metric ton (lb/ton) of 100 percent H2/SO4/ produced.
C=concentration of acid mist or SO2/, g/dscm (lb/dscf).
Qsd/=volumetric flow rate of the effluent gas, dscm/hr (dscf/hr).
P=production rate of 100 percent H2/SO4/, metric ton/hr (ton/hr).
K=conversion factor, 1000 g/kg (1.0 lb/lb).

(2) Method 8 shall be used to determine the acid mist and SO2/ concentrations (C's) and the volumetric flow rate (Qsd/) of the effluent gas. The moisture content may be considered to be zero. The sampling time and sample volume for each run shall be at least 60 minutes and 1.15 dscm (40.6 dscf).

(3) Suitable methods shall be used to determine the production rate (P) of 100 percent H2/SO4/ for each run. Material balance over the production system shall be used to confirm the production rate.

(4) Method 9 and the procedures in Sec.60.11 shall be used to determine opacity.

(c) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) If a source processes elemental sulfur or an ore that contains elemental sulfur and uses air to supply oxygen, the following procedure may be used instead of determining the volumetric flow rate and production rate:

(i) The integrated technique of Method 3 is used to determine the O2/ concentration and, if required, CO2/ concentration.

(ii) The SO2/ or acid mist emission rate is calculated as described in Sec.60.84(d), substituting the acid mist concentration for Cs/ as appropriate.

ACME Chemicals, Inc. acknowledges that performance tests shall be conducted as specified above.

Updates to the MBACT Determination for Elemental Phosphorus Process

P4 Production, L.L.C.

March 2015

Environmental Resources Management
700 W. Virginia Street, Suite 601
Milwaukee, WI 53204

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REPORT

Prepared For: P4 Production, L.L.C.

Updates to the MBACT Determination for Elemental Phosphorus Process

Soda Springs, Idaho

March 2015

Project Number: 0286394

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1.0 INTRODUCTION

Under State of Idaho rules at IDAPA 58.01.01.401.02.a.ii, existing sources with mercury air emissions above 62 pounds per year are required to perform a Mercury Best Available Control Technology (MBACT) analysis and submit a Tier II permit application for review and approval of the MBACT analysis by the Idaho Department of Environmental Quality (IDEQ). P4 Production, L.L.C., (P4) completed the required action for the MBACT analysis and Tier II permit application in April of 2012 to fulfill the requirements of IDAPA 58.01.01.401.02.a.ii. for sources of mercury emissions at their facility in Soda Springs, Idaho. IDEQ approved the MBACT and issued a Tier II Permit Number T2-2012.0016 to P4 in March 4, 2014.

As required by the Tier II Permit, P4 conducted source testing of the nodulizing kilns addressed in the Tier II Permit. The stack test results from December 2014 identified that annual emissions of mercury from the multiple control devices serving the kilns measured potential mercury emissions of 1078 pounds per year versus the 753 pounds per year supported in the 2012 MBACT analysis by testing conducted in 2002.

As requested by IDEQ, P4 is updating the 2012 MBACT analysis to address this adjustment to the annual mercury emissions from sources of mercury emissions at their facility in Soda Springs, Idaho based on testing performed in December 2014.

1.1 FACILITY DESCRIPTION

P4 Production, L.L.C. owns and operates an elemental phosphorous production facility (Facility) near Soda Springs, Idaho. The Facility processes phosphate ore to produce elemental phosphorus (P4) for sale. There are two primary departments at the Facility – the Burden Preparation Department and the Furnace Department.

The Burden Preparation Department includes activities associated with handling and beneficiation of raw materials (coke, quartzite, and phosphate ore) to produce a suitable feedstock for processing by the Furnace Department to produce elemental phosphorus. Ore is received and stockpiled onsite. Ore is then conveyed to a nodulizing kiln for processing.

The resulting nodules are cooled and stockpiled or sent directly to the nodule sizing and scale room from the cooler. In the scale room the nodules are blended with coke and quartzite. The coke and quartzite are received and stockpiled separately at the Facility and are dried to a desired moisture content, if necessary, prior to blending with the nodules.

The nodule-coke-quartzite blend (burden) is then sent to the Furnace Department for processing. Fuel used in the nodulizing kiln is primarily carbon monoxide (CO) off-gas from the furnace process which is supplemented with small quantities of natural gas and coal. The kiln off-gas is treated with existing air pollution control equipment including a series of dust bins, a spray tower, and four parallel hydrosonic venturi scrubbers. The hydrosonic venturi scrubbers are fed with lime concentrated dual alkali (LCDA) solution to scrub acid gases, primarily SO2, from the gas flow.

The Furnace Department operations utilize electric arc furnaces to melt the burden, chemically react the components, and create off-gases containing elemental phosphorus. The burden enters one of three electric furnaces (No. 7, No. 8, and No. 9) that operate on a continuous basis at temperatures of 1,400 to 1,500°C (2,550 to 2732°F). The reducing environment in the furnaces reacts phosphate from the nodules to form phosphorus gas, carbon monoxide gas, and molten slag and ferrophosphorus.

The furnace gases, composed of mainly carbon monoxide and phosphorus, are drawn through electrostatic precipitator (ESP) dust collectors where particulate matter is removed. The cleaned gases are then sent through water spray condensers where the gases are cooled - condensing the phosphorus. The condensed phosphorus is pumped to settling/storage tanks for further solids removal and product storage. The stored phosphorus is loaded into water-blanketed railroad cars for shipment to market.

After the removal of phosphorus, the furnace off-gas is composed primarily of CO and water vapor. The CO is sent to the nodulizing kiln as fuel. Excess CO is ducted to a thermal oxidizer (TO) unit to combust excess furnace gas and oxidize the remaining CO.

The furnaces are periodically tapped to remove accumulated molten slag and ferrophosphorus. Slag taps occur about 45-48 times per day per furnace and last about 15 minutes per tap. The ferrophosphorus is tapped once or twice per day per furnace. The tapping gases are collected by a Tap-Hole Fume Collector (THFC) and pass through a high-energy venturi scrubber equipped with a cyclonic separator before discharge to the atmosphere.

The molten slag is tapped into cast steel ladles that are transported and poured onto the slag storage pile at the site. The ferrophosphorus is also collected in ladles, cooled, and stockpiled on-site.

1.2 *MERCURY EMISSIONS*

The phosphate ore and various other raw materials used in the process contain trace amounts of mercury (Hg). Hg leaves the process either in solid process intermediates or in air emissions. An estimate of the amount of mercury from various process points is shown at the end of this section in Table 1. In addition, information on the form of mercury in the nodulizing kiln exhaust stack, the largest source of Hg air emissions, is presented in Table 2.

Mercury is a naturally-occurring metal normally found in trace amounts in rock and mineral formations. In the P4 production process, mercury exists in trace amounts in the ore and to a lesser extent other raw materials. Mercury has three possible valence states; elemental mercury (Hg^0), mercuric state (Hg^{2+}), and mercurous (Hg^+). Particle-bound mercury (Hg_{PB}) refers to mercury contained in particles in the gas stream. The exact speciation of Hg in raw phosphate ore is uncertain; however, at high temperatures within the kiln (~1500 °C) it is theorized that most of the Hg in the ore is volatilized and enters the process air stream as elemental mercury, Hg^0. This is supported by low relative quantities of Hg observed in discrete samples of ore and nodules.

As the process gases are cooled, the interactions of the gaseous elemental Hg^0 with other constituents in the gas results in a portion of the Hg^0 being converted to other forms. Generally, some amount of the Hg^0 is oxidized to Hg^{2+} or Hg^+. In theory, the oxidized Hg^{2+} compounds in the process gas include mercury chloride ($HgCl_2$), mercury oxide (HgO), and mercury sulfate ($HgSO_4$). There is no evidence that Hg^+ exists in the P4 processes. Some amount of mercury in the process exhaust gas exists as Hg_{PB}.

The oxidized and particle-bound forms of mercury are the readily controlled forms, while control of elemental Hg^0 is more challenging. In general, the mercury control strategies include maximizing the control of the Hg^{2+} and Hg_{PB} forms of mercury, and forcing the Hg^0 in the flue gas to the controllable forms.

The mercury emission estimates for the Facility show that approximately 99.6% of the mercury emitted to the atmosphere at the Facility is from the nodulizing kiln. An approximate material balance has shown that 23% of the mercury in the system is not emitted to the atmosphere as it is isolated from the system in the solid process intermediates and in the air pollution control system sludges. The highest measured level of mercury emissions from the nodulizing kiln is estimated to be 1078 lbs/yr based on Hg(g) and Hg(PM) stack test data on a maximum kiln throughput basis.

Nodulizing Kiln Emission Factor Calculation

Mercury emission test results:
Gaseous mercury: 0.1127 lb/hr (2014 stack test)
Ore throughput during 2014 gaseous test: 241.326 ton/hr
Particulate mercury: 0.00616 lb/hr (2014 stack test)
Ore throughput during 2014 particulate test: 241.326 ton/hr

Gaseous Hg emission factor:
$(0.1127 \text{ lb/hr})/(241.33 \text{ ton/hr}) = 4.67 \times 10^{-4} \text{ lb/ton}$

Particulate Hg emission factor:
$(0.00616 \text{ lb/hr})/(241.33 \text{ ton/hr}) = 2.55 \times 10^{-5} \text{ lb/ton}$

Overall Hg emission factor:
$4.67\times 10^{-4} \text{ lb/ton} + 2.55\times 10^{-5} \text{ lb/ton} = 4.92 \times 10^{-4} \text{ lb/ton}$
Maximum ore throughput:
$(249.9 \text{ ton/hr}) \times (8{,}760 \text{ hr/yr}) = 2{,}189{,}124 \text{ ton/yr}$

The annual Hg emission rate based on the highest measured rate is:

$$(4.92 \times 10^{-4} \text{ lb/ton}) \times (2{,}189{,}124 \text{ ton/yr}) = 1078 \text{ lb/yr}$$

Table 1 shows the potential emissions of mercury for all sources at the Facility that emit mercury. The information in Table 1 is estimated based on P4 Production's methodology for the annual reporting under the Toxic Release Inventory (TRI) regulation, and the potential to emit calculation above. The TRI values were scaled-up to a potential to emit using the nodulizing kiln potential to emit and assuming that the other sources are proportional to that value.

The estimates in Table 1 suggest there are two sources of mercury air emissions with total Hg emissions greater than 1 lb/yr; the nodulizing kiln and the nodule crushing and screening scrubber stack. In the nodule crushing and screening process, nodules are crushed and separated into fine, medium, and course grades as required for use as furnace feedstock. The sized nodules are routed into the scaleroom bins for proportioning into the furnace feedstock. The nodule crushing, sizing, and screening processes generates both point and fugitive particulate matter that is controlled by a wet scrubbing system and a baghouse. The low mercury content evaluated in grab samples of raw materials (nodules, coke, and quartzite) fed to the furnaces is consistent with the low emissions measured at the THFC stacks and other point sources.

Because the mercury emission estimate for the nodulizing kiln is more than two orders of magnitude higher than emissions from the nodule crushing and screening process or any other source of mercury emissions at the Facility, this MBACT review focuses on control of mercury from the nodulizing kiln.

Table 1 – Estimated Potential Mercury Emissions

Process Area	Emission Estimate (lb/yr)
Kiln Hydrosonics	1078
Nodule Crushing and Screening Scrubber	2.80
Cooler Spray Tower	0.96
#7 THFC	0.07
#9 THFC	0.02
#8 THFC	0.07
SDM Bin Vent	3.02E-04
Coke Handling Baghouse (C&Q)	7.76E-05
Nodule Reclaim Baghouse	6.11E-04
Scaleroom Baghouse	1.14E-04
Main Furnace Baghouse	3.96E-05
No. 9 CO Dust Baghouse	9.07E-06
No. 8 CO Dust Baghouse	9.34E-06
Dryer BH	2.86E-05
#309 Coke Fines Bin Vent	4.81E-06
No. 7 CO Dust Baghouse	4.44E-06
#9 CO Dust Collection Bypass	3.10E-06
#8 CO Dust Collection Bypass	4.89E-06
#305 Coke Fines Bin Vent	1.69E-06
#307 Coke Fines Bin Vent	1.93E-06
#7 CO Dust Collection Bypass	1.45E-06
105 Baghouse	1.10E-05
#304 Coke Fines Bin Vent	5.94E-07
#308 Coke Fines Bin Vent	1.10E-06
104 Baghouse	1.06E-03
#306 Coke Fines Bin Vent	7.32E-07
Coke Bunker Baghouse	7.39E-08
Bulk Storage Bin Baghouse (Coke Fines BH)	8.70E-09
Vactor Truck Vent - C&Q BH Unloading	1.25E-08
Vactor Truck Vent - Scaleroom BH Unloading	5.10E-09
Vactor Truck Vent - Scaleroom Vacuum System	5.10E-09
Vactor Truck Vent - Coke Bunker BH Unloading	2.36E-09
Vactor Truck Vent - Dryer BH Unloading	4.09E-09
Vactor Truck Vent - 105 BH Unloading	4.07E-09
Vactor Truck Vent - Main Stocking BH Unloading	3.78E-09
Vactor Truck Vent - Dust Container Unloading	3.65E-09
Vactor Truck Vent - Lab BH Unloading	6.02E-10
Thermal Oxidizer	1.03
TOTAL Hg Emissions	**1083**

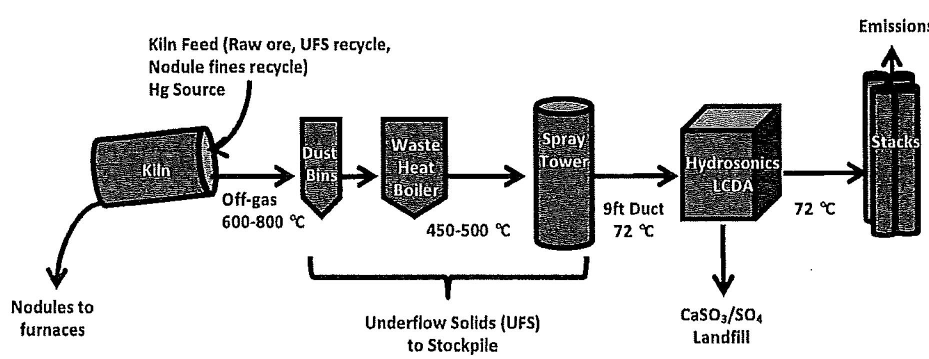
The estimated speciation of mercury air emissions from the nodulizing kiln is shown in Table 2. The information shown in Table 2 is from the 2014 emission tests (Ontario-Hydro Method, ASTM D6784-02) conducted on the four nodulizing kiln stacks. This data indicates that elemental mercury, the most difficult and costly form to control, is the predominant species in the nodulizing kiln stack emissions.

Table 2 - Mercury Speciation from 2014 Emissions Test Data – Nodulizing Kiln

Hg Species	Percent of Total (Low)	Percent of Total (High)
Hg_{PB}	1.32	2.01
Hg^{2+}	1.81	8.23
Hg^0	89.76	96.87

A representative process flow diagram of the nodulizing kiln is presented in Figure 1. This process flow diagram is the basis for discussion in the step by step control technology discussion in the following review.

Figure 1 – Nodulizing Kiln Process Flow Diagram



As noted in Figure 1, emissions from the kiln are exhausted in an air stream of approximately 260,000 acfm and an elevated temperature of 600 to 800 °C. The temperature of the air stream drops to approximately 450-550 ° C following the waste heat boiler and further to 72°C as it exits the Spray Tower. The total exhaust at the four stacks is approximately 300,000 acfm.

In addition, Figure 1 shows the existing control equipment on the nodulizing kiln. The existing control consists of the dust bin, spray tower, and four hydrosonic venturi scrubbers. The hydrosonic venturi scrubbers are fed with LCDA solution to scrub acid gases, primarily SO_2, from the gas flow. Approximate mass balance from grab samples and analytical test results suggests approximately 23% of the mercury in the ore leaves the system in the solids streams and 77% is in the exhaust gas. This MBACT review investigates technologies that can reduce the gaseous elemental mercury that remains in the nodulizing kiln exhaust gas.

2.0 *TOP-DOWN MBACT PROCESS*

MBACT requirements are intended to ensure that the subject emission unit will incorporate control systems that reflect the latest demonstrated practical techniques for that particular emission unit for an applicable pollutant. The MBACT evaluation requires the documentation of performance levels achievable for control technology on a pollutant-by-pollutant basis. MBACT is defined in the IDEQ regulations (IDAPA 58.01.01.006.67) as:

> *An emission standard for mercury based on the maximum degree of reduction practically achievable as specified by the Department on an individual case-by-case basis taking into account energy, economic and environmental impacts, and other relevant impacts specific to the source.*

This MBACT analysis will use an analysis process that is recommended by USEPA for determining Best Available Control Technology (BACT), a similar control standard. USEPA recommends that a "top-down" approach be taken when evaluating available air pollution control technologies. This approach to the BACT process involves determining the most stringent control technique available, Lowest Achievable Emission Rate (LAER), for a similar or identical emission source. If it can be shown that the LAER is technically, environmentally, or economically impractical on a case-by-case basis for the particular source, then the next most stringent level of control is determined and similarly evaluated. The process continues until a control technology and associated emission level is determined which cannot be eliminated by any technical, environmental, or economic objections.

The top-down BACT evaluation process is described in the USEPA draft document "New Source Review Workshop Manual." The five steps of a top-down BACT evaluation are:

1. Identify all available control options with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;

2. Eliminate technically infeasible or unavailable technology options;

3. Rank remaining control technologies by control effectiveness;

4. Evaluate most effective controls and document results; if top option is not selected as BACT, evaluate next most effective control option; and

5. Select BACT, which will be the most effective practical option not rejected based on energy, environmental, and economic impacts.

The "top-down" approach is used in this analysis to evaluate available pollution controls for each of the pollutants subject to BACT from each source of those emissions proposed.

2.1 *LOWEST ACHIEVABLE EMISSION RATES*

While the proposed project is not subject to the requirement to install LAER for any pollutant, in a "Top Down" control technology analysis LAER is used as the starting point since it establishes the lowest emission level that has been demonstrated in practice for a similar unit. The processes at the Facility are unique as the Facility is the only known elemental phosphorus process in North America. LAER, as defined in the "New Source Review Workshop Manual" (USEPA 1990), is derived from either of the following definitions:

> *"The most stringent emission limitation contained in the implementation plan of any State for such class or category of source; or the most stringent emission limitation achieved in practice by such class or category of source."*

The LAER standard is typically intended to be more stringent than BACT, since it is applied to sources in non-attainment areas and considers only the technical feasibility of the best level of control that has been achieved in practice on another similar unit, without consideration of potential adverse economic, environmental, or energy impacts. It does, however, represent a useful starting point in the evaluation of potentially achievable levels of control. To determine the applicable emission limitations that would be representative of LAER the EPA BACT/RACT/LAER Clearinghouse (RBLC) was consulted.

An emission limit proposed in a permit application does not automatically mean that that limit has been "achieved in practice" on a similar unit. Many PSD permits have been issued over the years for projects that were never constructed. There are also instances where incorrect limits have been posted to the RBLC or where the ultimate permit limits were subsequently modified prior to permit issuance. In some cases an applicant may have proposed very stringent limits without a meaningful commercial guarantee, perhaps to avoid a more onerous requirement or an unacceptable air quality impact, and not be able to continuously achieve the limits in practice. An emission rate based on a BACT finding must be met continuously under normal operations, not just at one optimal design point. Therefore, there must be a reasonable assurance that each BACT limit evaluated is truly "demonstrated in practice" on a similar unit, and can be continuously achieved under all expected operating conditions.

2.2 COST ESTIMATES

Cost analyses of certain technically feasible control alternatives were prepared and are presented to compare capital and annual costs in terms of cost effectiveness (i.e., dollars per pound of pollutant removed). Capital costs include the initial cost of components intrinsic to the complete control system (for example including a reactor vessel, catalysts or internals, support steel, ductwork, reagent storage, piping, rotating equipment, instrumentation, monitoring equipment and installation costs). Annual operating costs consist of the financial requirements to operate the control system on an annual basis and include overhead, maintenance, outages, labor, raw materials, and utilities.

2.2.1 Capital Costs

The capital cost estimating technique used in this analysis is based on a factored method of determining direct and indirect installation costs. The cost methodology is found in Chapter 1 of the USEPA OAQPS Manual (EPA-452/B-02-001) and adjusted from 1998 dollars using the Engineering News Record Construction Cost Index. This method is consistent with the latest USEPA guidance manual (OAQPS Control Cost Manual) on estimating control technology costs (USEPA, February 1996). The estimation factors used to calculate total capital costs are shown in Table 3.

In order to address any changes in capital costs for this updated MBACT analysis, the *Engineering News Record* (ENR) capital cost index was obtained. The index has risen from the value of 9412 in 2011 to 9962 for 2014, an increase of 5.8%. Therefore, the capital costs in this update were adjusted upward in accordance with the ENR values by 5.8%.

Purchased equipment costs represent the delivered cost of the control equipment, auxiliary equipment, and instrumentation. Auxiliary equipment consists of all structural, mechanical, and electrical components required for efficient operation of the device. These include such items as reagent storage and supply piping and distributed controls.

Auxiliary equipment costs are taken as a straight percentage of the basic equipment cost, the percentage being based on the average requirements of typical systems and their auxiliary equipment (USEPA, February 1996). In this control alternatives evaluation, basic equipment costs were estimated based on published cost estimating methodologies. Instrumentation, usually not included in the basic equipment cost, is estimated at 10 percent of the basic equipment cost (major components).

Direct installation costs consist of the direct expenditures for materials and labor for site preparation, foundations, structural steel, erection, piping, electrical, painting, and facilities. Indirect installation costs include engineering and supervision of contractors, construction and field expenses, construction fees, and contingencies. Direct installation costs are expressed as a function of the purchased equipment cost based on average installation requirements of typical systems and may tend to underestimate actual costs in a northern climate installation such as Soda Springs.

Indirect installation costs are designated as a percentage of the total direct cost (purchased equipment cost plus the direct installation cost) of the system. Other indirect costs include equipment startup and performance testing, working capital, and interest during construction. In addition, costs such as lost production or rental fees for temporary equipment can be included if appropriate.

Table 3 - Capital Cost Estimation Factors

Item	Basis
Direct Costs	
Purchased Equipment Cost	
Equipment cost + auxiliaries	A
Instrumentation	0.10 x A
Freight	0.05 x A
Total Purchased equipment cost, (PEC)	B = 1.15 x A
Direct installation costs	
Foundations and supports	0.08 x B
Handling and erection	0.14 x B
Electrical	0.04 x B
Piping	0.02 x B
Insulation for ductwork	0.01 x B
Painting	0.01 x B
Total direct installation cost	0.30 x B
Site Preparation	As Required
Buildings	As Required
Total Direct Cost, DC	1.30B + SP + Bldg.
Indirect Costs (installation)	
Engineering	0.10 x B
Construction and field expenses	0.05 x B
Contractor fees	0.10 x B
Start-up and Performance test	0.03 x B
Contingencies (for Routine Application of Technology)	0.03 x B
Working Capital (30 days O&M cost)	Not Used
Total Indirect Cost, IC	0.31B + WC
Total Capital Investment (TCI) = DC + IC	**1.61B+ SP + Bldg. + WC**

2.2.2 *Annualized Costs*

Annualized costs are comprised of direct and indirect operating costs. Direct costs include labor, maintenance, replacement parts, raw materials, utilities, and waste disposal. Indirect operating costs include plant overhead, taxes, insurance, general administration, and capital charges. Annualized cost factors used to estimate total annualized cost are listed in Table 4. Annualized cost factors were obtained from the latest USEPA guidance manual on estimating control technology costs (USEPA, February 1996).

Direct operating labor costs vary according to the system operating mode and operating time. Labor supervision is estimated as 15 percent of operating labor. Maintenance costs are calculated as 3 percent of total direct cost (TDC). Raw material and utility costs are based upon estimated annual consumption and the unit costs are summarized in Table 4.

With the exception of overhead, indirect operating costs are calculated as a percentage of the total capital cost. The indirect capital costs are based on the capital recovery factor (CRF), defined as:

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

Where i is the annual interest rate and n is the equipment economic life (years). A control system's economic life is typically 10 to 20 years (USEPA, February 1996). In this analysis, a 10 year equipment economic life (typical length of financing) was used. The average interest rate is assumed to be 7 percent (USEPA, February 1996). CRF is therefore calculated to be 0.081.

Table 4 - Annualized Cost Factors

Item	Cost Factor	Unit Cost
Direct Annual Costs, DC		
Operating labor		
Operator	variable hr/shift	$45.00/hr
Supervisor	15% Operating Labor	NA
Maintenance		
Labor Req.	variable hr/shift	$52.50/hr
Material	100% Maintenance Labor	NA
Supervisor	15% Labor	NA
Utilities		
Electricity	NA	**$0.043/kWh**
Indirect Annual Costs, IC		
Overhead	44% of DL + 12% ML	
Administrative Charges	2% TCI	
Insurance	1% TCI	
Capital Recovery	CRF x TCI	
Total Indirect ($/yr)		
Total Annual Cost (TAC) ($)		Sum of Annual Costs
Total Pollutant Controlled (ton/yr) Based on Max. PTE	As Calculated	
Cost Effectiveness ($/lb) Based on Max. PTE		**TAC/lb/yr controlled**

2.2.3 *Cost Effectiveness*

The cost-effectiveness of an available control technology is based on the annualized cost of the available control technology and its potential annual pollutant emission reduction. Cost effectiveness for a given control technology is calculated by dividing the annualized cost of the control technology by the theoretical pounds of mercury removed each year.

2.3 *RBLC SEARCH*

The EPA compiles and maintains a national database of facilities with permitted air emissions, by industrial classification. The database includes information by facility and individual emission units. A complete RBLC listing for a given facility will include the date of issuance of the permit, the permitted air pollutants and the corresponding emission limits as well as the control technologies employed to meet those limits.

A database search was conducted for the following industrial source categories:

- Phosphorous Production Plants (90.013)
- Phosphate Fertilizer Production (61.009)
- Phosphoric Acid Manufacturing (62.010)
- Calciners, Dryers and Mineral Processing Facilities (90.017)
- Portland Cement (90.028)
- Phosphate Rock Processing (90.026)
- Municipal Waste Combustion (21.400)

For this updated MBACT analysis, the EPA RBLC was again accessed to obtain any changes to the database since the 2012 MBACT analysis was prepared. Three new entries were identified in the RBLC which included efficient combustion practices, particulate control with a bag filter and activated carbon injection (ACI). Efficient combustion practices are not germane to this MBACT analysis and particulate control with a bag filter and ACI are addressed in this MBACT analysis. The three new entries are added to the RBLC listing in Appendix A.

The searches were conducted for permits issued after January 1, 2000. In addition to the above source categories, a search was conducted for any reference to mercury in an air permit. Appendix A shows all facilities that had some reference to mercury emission controls and/or standards. A majority of these facilities do not incorporate mercury control technologies specifically; some refer to material balance to arrive at mercury limits while others control mercury as a co-benefit of existing, multi-pollutant controls.

Most of the sources identified through the RBLC review have no mercury control listed and appear to have mass balance based limits. Of the sources with add-on control listed, activated carbon injection is the most prominent control technology with flue gas scrubbing as the next most common control. Both of these technologies have potential for mercury removal at the Facility and will be further evaluated as part of the MBACT analysis.

2.4 *REGULATORY REVIEW*

As a part of the MBACT analysis, a review was performed to determine if there are any current or proposed regulatory requirements that would limit mercury emissions from the Facility, or would limit mercury emissions from similar types of sources to those operated by P4. There are no current or proposed National Emission Standards for Hazardous Air Pollutant (NESHAP) regulations that would limit mercury emissions from P4's operations, nor are there any NESHAP regulations that would limit mercury emissions from new sources comparable to P4.

3.0 *MBACT ANALYSIS*

The following section presents the 5-step MBACT review process for the affected process at the Facility. The available control technologies are identified including potentially transferable technologies from other industries applied to similar sources. For the purpose of this evaluation, similar sources are gas streams with trace amounts of mercury in the gas stream. Technologies that are technically infeasible are then eliminated from further consideration. Technical feasibility is related to specific challenges in applying a given technology due to physical or chemical characteristics of the process.

The technologies found to be technically feasible are then ranked by control effectiveness and evaluated further based on cost. Finally, the control technology that represents MBACT for the nodulizing kiln is selected and a numerical emission limit is proposed.

3.1 *STEP 1 - IDENTIFY CONTROL TECHNOLOGIES*

Potentially applicable control technologies were identified through review of available literature, the RBLC, vendor information, and through discussions with vendors. A considerable amount of literature review was performed for the 2012 MBACT analysis to identify control technologies transferable to the unique source at the facility – the nodualizing kiln exhaust. The emphasis for this MBACT update was to identify if any new technologies were introduced and to determine if advancements were made on technologies emerging in 2012. A detailed search of common scientific, industrial and news related databases limited to the past two years identified that the technologies identified in the 2012 MBACT analysis have not made any advancements that would change the position communicated in the 2012 MBACT analysis. It appears that most of the focus in the industry over the past few years has been on the implementation of developed technologies as designed, and on measurement system increases. Therefore the technologies identified in the 2012 MBACT analysis are included again in this 2015 update.

The following common technologies are identified for control of dilute mercury emissions from the nodulizing kiln:

- ACI and bromated activated carbon injection (BACI),
- Non-carbon sorbent/reactant injection,
- Halogen injection and BACI,

- Fixed-Bed Oxidation catalysts,
- Ore pre-treatment, and
- Mercuric chloride scrubbing.

Each of these control technologies is discussed in more detail in the following subsections. Because the Facility operations are unique, all technologies identified represent a transfer of technology from another source type. Technology transfer and retrofit issues present a challenge to application of any of the technologies identified. No control technology vendor or engineer, procure and construct contractor would offer a guarantee of performance for such a system. Potential control technologies that are in the laboratory stage of development or theorized as potentially effective are not included on the list of identified technologies and were not evaluated in the 5-step process.

3.1.1 *Activated Carbon Injection (ACI) and Bromated Activated Carbon Injection (BACI)*

The leading mercury control technology for control of trace amounts of mercury in a gas stream is ACI upstream of a particulate control device. A variant of the ACI technology is the use of halogenated activated carbon.

Elemental mercury reacts with all the halides to give Hg^{2+} salts as follows:

$$Hg + F_2 \rightarrow HgF_2$$
$$Hg + Cl_2 \rightarrow HgCl_2$$
$$Hg + Br_2 \rightarrow HgBr_2$$
$$Hg + I_2 \rightarrow HgI_2$$

Thus, halogenated activated carbon promotes the oxidation of elemental mercury to the controllable Hg^{2+} form via scrubbing and sorption onto AC surface. Bromine is the halogen of choice because of cost and effectiveness.

Both ACI and BACI have been studied in the electric power generation industry for application on coal-fired power plants and have the potential to achieve moderate to high levels of mercury control. Control efficiencies of 70% to 90% or higher are achievable on coal-fired power applications. The mechanism of capture with ACI and BACI is adsorption where the target pollutant chemically bonds to adsorption sites on the surface of the carbon, and then the carbon is removed from the gas steam in the particulate collection device(s) and kept from reaching the atmosphere, although shifted to potential land or water impacts.

The performance of activated carbon is related to its physical and chemical characteristics. Generally, the physical properties of interest are surface area, pore size distribution, and particle size distribution, and as with any chemical treatment system, the reaction temperature, good mixing, and residence time are important to the design of an ACI or BACI system. The capacity for Hg capture generally increases with increasing surface area and pore volume. ACI systems perform best at flue gas temperatures between 200° and 400° F.

The ability of Hg and other gas constituents to penetrate into the interior of an ACI or BACI particle is related to pore size distribution. The pores of the carbon sorbent must be large enough to provide free access to internal surface area by Hg^{2+} while avoiding excessive blockage by previously adsorbed mercury and non-target gas constituents (i.e., SO_2, other metals, etc.) As the carbon particle sizes decrease, access to the internal surface area of the particle increases along with potential adsorption rates.

In a well-designed system, mercury has a high affinity to activated carbon and there are minimum amounts of other trace gas constituents to compete with mercury for adsorption sites.

The resulting mercury-containing carbon is collected along with other particulates by a downstream control device, such as a wet scrubber, ESP, or fabric filter. Generally, the solid residue captured in the downstream particulate control device can be safely disposed of in a landfill or sent off-site to be regenerated because mercury is chemically bound to the carbon and not susceptible to leaching out of the spent carbon.

3.1.2 *Non-Carbon Sorbent/Reactant Injection*

Research into sorbent alternatives to ACI and BACI is ongoing and is primarily focused on calcium and calcium silicate cased sorbents. Some of these sorbents have the potential to work at a higher temperature range than ACI and BACI and have been shown to be effective on both elemental and oxidized mercury. The following is a brief summary of the non-carbon absorbents under investigation:

- The mineral sorbent Minplus® was tested at a number of coal-fired power plants including Minnesota Power's Taconite Harbor Power Plant, and Richmond Power & Light's Whitewater Valley Power Plant. The Taconite Harbor test results were poor with little or no mercury removal reported. The Whitewater Valley test results showed a high level of mercury removal attributed to the high degree of mixing provided by the rotating opposed-fired air system of that particular unit. The injection point was at approximately 1,200 °F.

- Novinda Corporation is currently running full-scale, power plant tests of its amended silicates product, a clay-based sorbent designed to capture both elemental and oxidized mercury. The flue gas temperatures in these tests are around 300°F.

- TDA Research has conducted slip-stream tests on the effectiveness of injection of their proprietary non-carbon sorbent at Xcel Energy's Pawnee Power Plant. The slip-stream tests showed promising results at injection temperatures up to 475 °F.

A promising non-carbon reagent injection system involves sodium tetrasulfide (Na_2S_4) as the reagent. This reagent is injected into the flue gas as an aqueous solution and converts vapor phase mercury to solid mercuric sulphide (HgS). Mercuric sulfide is a stable solid at normal temperatures that can be collected in a particulate control system and sent to disposal. Babcock Power reports that Na_2S_4 will remove both Hg^0 to Hg^{2+} based on pilot scale tests conducted at an injection temperature of 300°F.

Other studies have investigated iodine and chlorine to promote oxidation of mercury. The evaluations of iodine have shown that other gas constituents readily interfere with the iodine-mercury reaction. Chlorine is supplied by injecting chloric acid ($HClO_3$) and sodium hypochlorite (NaOCl) into the gas stream. The literature indicates very high dose rates of both reagents are necessary to achieve significant oxidation of elemental mercury, with NaOCl showing the best results with the lowest injection concentration. Neither of these approaches has been evaluated on full-scale industrial facilities.

3.1.3 *Halide Injection and ACI*

The following is a brief discussion of halogen addition to a gas stream with trace amounts of mercury to promote the oxidation of elemental mercury so that a carbon adsorption system such as ACI can be enhanced.

The addition of small amounts of bromide containing reagents into coal-fired boilers has been shown to drive the oxidation of elemental mercury in the flue gas. The preferred method is to spray a salt solution of calcium bromide ($CaBr_2$) onto the coal before it enters the boiler furnace. The $CaBr_2$ disassociates at high temperatures, with the bromide ionizing to initiate a complex mechanism to oxidize Hg^0 to form Hg^{2+} as the gas cools.

Suppliers of this technology include Nalco Mobotec (Mercontrol) and Alstom Power (KNX), both of whom were consulted as part of this study.

3.1.4 *Fixed-Bed Oxidation Catalysts*

Experiments at coal-fired power plants have revealed the potential for catalyst beds to promote the oxidation of elemental mercury. Some catalysts lower the activation energy for the oxidation of elemental mercury. Catalyst materials are made from various metal oxides and metal alloys. URS Corporation and Babcock & Wilcox have both done extensive research in this area. At utility boilers, the precious metal catalysts used in selective catalytic reduction (SCR) systems installed to control boiler NOx emissions have the co-benefit of oxidizing elemental mercury. These catalysts are located in the optimum temperature window for NOx reduction (above 700°F). One mercury control challenge presented by SCR is that a small portion of SO_2 in the gas stream is oxidized to SO_3 over the catalyst bed and SO_3 is a gas constituent that impedes mercury recovery.

3.1.5 *Ore Pre-Treatment*

This technology involves solid or liquid-phase separation of the mercury from the phosphate ore prior to its introduction into the Kiln. Possible techniques include acid wash or cyanide leaching. There is no ore pre-treatment process for the purpose of removal of mercury at any operating facility. Further discussion of this option is presented in Step 2.

3.1.6 *$HgCl_2$ Scrubbing and Other Metals Refining Hg Recovery Methods*

Mercury emissions control technologies used in metals refining include ore roasters equipped with chloride-based scrubbers, fixed-bed carbon filtration, scrubbing with sulfuric acid and selenium filters, autoclave treatment, and various retort technologies. Further discussion of this option is found in Step 2.

3.2 *STEP 2 - ELIMINATE TECHNICALLY INFEASIBLE CONTROL OPTIONS*

The following discussion considers the technical feasibility of application of control technologies identified in Step 1 of this review. The reasons for eliminating identified control technologies at this point of the review include commercial availability, and physical/chemical technical challenges associated with successful implementation of the control.

3.2.1 *ACI and BACI*

ACI and BACI are well studied in the coal-fired electric power generation industry; however, coal-fired power generation units have exhaust gas characteristics that are different from the nodulizing kiln at the Facility. The following differences are deemed to be important in considering ACI or BACI for the nodulizing kiln:

- Mercury Speciation,
- Compounds and ions present that compete for activated carbon sites,
- Temperatures out of range, and
- Particulate recovery efficiency in wet scrubber.

The affinity of Hg^{2+} for activated carbon is significantly greater than that for Hg^0. Hg^0 is the dominant mercury species in the kiln off-gas at the stack, and must first be oxidized in order to be adsorbed by the carbon. Recent stack testing in 2014 identified that elemental mercury is 89% to 97% of the mercury in the exhaust. However, Hg^0 oxidation is inhibited by reaction kinetics at off-gas temperatures prior to the spray tower (842-1022 °F) coupled with the absence of suitable gas phase Hg^0 oxidants. In addition, it is important to consider the concentrations of other constituents of the gas stream including metal ion compounds and sulfur trioxide (SO_3) as these can also be adsorbed by the carbon, reducing its capacity to adsorb mercury.

In the case of P4, the kiln off-gas contains other metallic species with an affinity for AC at concentrations much greater than mercury. SO_3 concentrations in this gas stream, on the order of 5 to 10 ppmv, pose a lesser threat to compete with mercury. However, one utility test showed significantly impaired mercury capture at SO_3 concentrations of just a few ppmv in flue gas streams[1]. It appears likely that all of these constituents would compete with mercury to some degree and make an ACI or BACI system ineffective.

Additionally, ACI and BACI systems perform best at flue gas temperatures between 200 and 400°F, whereas the gas stream in the P4 process is either much higher (600 - 1,100°F before the spray tower) or marginally lower (160° F after the spray tower). ADA Environmental

[1] Meserole, F., Miller, S., Richardson, C., Implications of SO3 Removal on Mercury Capture, Proceedings of the 2006 Environmental Controls Conference USDOE NETL (2006)

Solutions (ADA-ES) reports optimum mercury capture at 200° F and other studies have shown that ACI effectiveness drops off above 300° F [2].

Finally, it is not clear that the venturi scrubbers can handle the additional loading of ACI or BACI. The venturi wet scrubbers operate with 40 inches (wc) of pressure drop can yield a 99% capture efficiency at particle sizes of more than 7 μm; however, the carbon particles would add an abrasive particle to the venturi throat and degrade the venturi performance.

All of the issues with ACI and BACI discussed above represent challenges to an effective control system These challenges include the temperature of the adsorption, the greater affinity of the nodulizer gas constituents other than mercury to activated carbon, and the ability to effectively remove the spent carbon from the gas flow before it is discharged to the atmosphere. Therefore, control by ACI and BACI prior to the venturi scrubbers are deemed technically infeasible for mercury control.

An ACI or BACI system could be designed downstream of the venturi scrubbers that would include ACI or BACI, reheating the flue gas to the target temperature and above the saturation temperature, and a baghouse or other particulate matter removal device for carbon removal. For this reason, ACI and BACI are retained for further evaluation.

3.2.2 *Non-Carbon Sorbent*

The Minplus product, a non-carbon sorbent, is owned by Nalco Mobotec. A representative of Nalco Mobotec indicated that the company has dropped development of the technology in the United States and that product is currently only available in Europe. Because this is an unproven technology for application to an emission unit such as the nodulizer at the Facility and it is not currently available in the United States, Minplus is dropped from further consideration and eliminated as a candidate for MBACT level control technology for the nodulizing kiln.

A representative of Novinda speculated that amended silicates might increase the gas viscosity and adversely affect the performance of the venturi scrubbers. For this reason, the Novinda amended silicates are eliminated from further consideration as representing MBACT from the nodulizing kilns.

TDA Research has conducted slip-stream tests on the effectiveness of injection of their proprietary non-carbon sorbent at Xcel Energy's Pawnee

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[2] Communication with Robert Wewer, Technology Manager, ADA-ES Inc., November 17, 2099. USEPA Whitepaper, Control of Mercury from Coal-Fired Utility Boilers (www.epa.gov/ttn/atw/utility/hgwhitepaperfinal.pdf)

Power Plant; however at present no conclusions can be drawn as to its commercial effectiveness. In the context of a BACT analysis, EPA states that a control technique is considered available if it has reached the licensing and commercial sales stage of development. The TDA Research proprietary sorbent is eliminated from further consideration as representing MBACT because it has not been demonstrated in practice and is not commercially available.

It is difficult to project the Babcock Power test results on the effectiveness of sodium tetrasulfide (Na_2S_4) onto controlling emissions from the nodulizing kiln. The Babcock Power pilot test injected the sorbent at gas temperatures of 300° F and collected the solid residue in a fabric filter (potentially prolonging the available reaction time). In addition, Na_2S_4 has not yet been commercialized despite the elapsed time since pilot testing began. Finally, Na_2S_4 was determined to be technically infeasible by Excel Energy for its King Generating Facility in Minnesota, based on contradictory results[3]. Because the technology is still under development and not commercially available, Na_2S_4 reagent injection is eliminated from further consideration as representing MBACT for the nodulizing kiln.

3.2.3 *Halide Injection and ACI*

For the purposes of this study, calcium bromide ($CaBr_2$) injection into the gas stream is included as an option for the cost review. Injection of calcium bromide upstream of the venturi scrubbers will promote the oxidation of elemental mercury. This option will make lining of the 9 foot diameter duct with fiber reinforced plastic necessary to protect against corrosion. Calcium bromide was evaluated because it is the most common source of halide and because P4's supporting search of RBLC and other literature did not identify other commercially available halides in use for mercury control.

Although evaluated for this MBACT analysis, calcium bromide injection is technically challenging for use in P4's operations because halide injection requires elevated temperatures and sufficient residence time to promote the oxidative conversion of elemental mercury into divalent mercury for subsequent capture in aqueous scrubbers or activated carbon. A solution of calcium bromide would presumably be injected into the kiln, or sprayed onto the ore feed. The kiln sustains sufficiently high temperatures to disassociate the calcium bromide (which requires 1,300° F or higher).

[3] Mercury Control Plan for the Allen S. King Plant: Pursuant to the Minnesota Mercury Emission Reduction Act of 2006, submitted by Excel Energy to the Minnesota Public Utilities Commission: December 21, 2007

Oxidation of the Hg^0 would begin at gas temperatures below 1,000° F and would continue until the gas drops below 300° F. The gas should remain within this temperature range for at least two or three seconds to provide sufficient contacting time to oxidize the mercury. But, as described in this MBACT analysis, the Kiln off-gas temperature drops rapidly in the spray tower from 1,100° F to 160° F, bypassing the working temperature range needed for the bromide anion to oxidize the mercury. In other words, water soluble gas phase bromide species would be scrubbed in the spray tower before having the opportunity to oxidize metallic mercury in the lower temperature region beyond the spray tower.

In order to consider this control option in this MBACT analysis, P4 evaluated using a combination of halide injection in the 9′ duct to promote oxidation of mercury to Hg^{2+}, gas reheat and a baghouse for ACI removal. This is explained in more detail in Section 3.3.

Calcium bromide injection is also technically challenging for use in P4's operations because there is potential for accelerated corrosion of ductwork and expensive process equipment. While bromide is considered to be less corrosive and more reactive towards mercury than other halides that have been injected into coal-fired boilers such as chloride, the long-term performance and equipment corrosion data for all the components that come into contact with the gas stream is not available.

To minimize corrosion in equipment, P4 would line affected ductwork with fiber reinforced plastic in order to consider this control option in this MBACT analysis.

In addition to the options discussed above for mercury control, P4 also considered injection of sodium hypochlorite solution into the kiln exhaust stream. This technique was specifically developed and proposed by the EPA ORD for P4 during an ICR related to a MACT evaluation in 2010. P4 and the EPA Region X and ORD collaborators determined this control to be technically infeasible because P4's existing equipment does not offer either the temperature or contact time required for mercury oxidation, and the soluble halide type species injected would be scrubbed and neutralized by the spray tower and/or venturi scrubbers prior to having any impact on mercury control. In addition, the resulting chloride would result in the rapid corrosion of gas and water handling equipment. Also, it is notable that the management of process water treatment facility at P4 is dependent on the accumulation of dissolved chlorides to mitigate corrosion and prevent the loss of equipment. EPA ORD has not pursued its proposal to test this control.

HCl injection was not evaluated in this MBACT analysis because it was not identified as a commercially utilized mercury control reagent, and because it would have a similar negligible impact on mercury control and induce corrosion.

Halide injection in combination with the existing dual alkali (wet flue gas desulfurization scrubbers) was determined to be technically infeasible because stack tests suggest that the conversion of SO_2 into SO_3^- and SO_4^{-2} byproducts by the scrubbers may create a reducing environment for the re-emission of Hg^0. While chemical binding and complexing agents are available to prevent oxidation of divalent mercury and re-emission as gaseous elemental mercury, P4 is not aware of any testing with respect to their compatibility with complex dual alkali aqueous chemistries that would support their use for the capture of elemental mercury.

3.2.4 *Fixed-Bed Oxidation Catalysts*

Fixed-bed oxidation catalysts would not be effective with the nodulizing kiln off-gas. Placement of the catalyst in the high-dust environment upstream of the spray tower (see Figure 1) would cause erosion of the catalyst surface or fouling of active catalyst surface if accumulation of solids were to occur. Furthermore, the presence of high sulfur dioxide concentrations would promote formation of sulfur trioxide and inhibit the oxidation of mercury at the catalyst.

If placed downstream from the spray tower a low-temperature catalyst would need to be used and there is little information in the literature to suggest that such a catalyst would promote mercury oxidation. Additionally, the same challenge with sulfur trioxide inhibiting the oxidation of mercury would exist at that location. In addition, the size of the fixed bed would be large and there are uncertainties around the durability of fixed-bed catalyst. Based on these concerns, a fixed-bed oxidation catalyst is eliminated from further consideration as representing MBACT for the nodulizing kiln.

3.2.5 *Ore Pre-Treatment*

This technology involves solid or liquid-phase separation of the mercury from the phosphate ore prior to its introduction into the Kiln. No precedent was found for this type of pretreatment of phosphate ore to capture mercury and would require significant process development. If effective pretreatment were developed, it would result in additional waste streams and environmental liabilities. Moreover, it would require radical process changes that exceed the scope of a MBACT analysis.

When considering available control alternatives under BACT, EPA has not considered the BACT requirement as a means to redefine the design of the source. For this reason ore pre-treatment is eliminated from further consideration as representing MBACT for the nodulizing kiln.

3.2.6 *$HgCl_2$ Scrubbing and Other Metals Refining Hg Recovery Methods*

All of the mining processes are designed to treat lower gas flow rates with higher mercury concentrations than those associated with the Kiln off gas (which has comparatively high flow rates of 300,000 acfm and comparatively low mercury concentrations of 0.3 mg/dscm). Fixed-bed filtration of the Kiln off-gas would employ a granular bed of carbon (possibly sulfur-impregnated) several feet thick, with a required surface area on the order of 2,000 ft2 (e.g. 40 ft x 50 ft). Along with impractical space requirements, energy consumption to move this volume of gas through the bed would be high. The potential also exists for blinding of the activated carbon sites by fine particulates that pass through the venturi scrubber system. Similar challenges exist with selenium filters. Autoclaves are used at Newmont's Twin Creek gold mine in Nevada, to recover mercury from ore with concentrations approaching 200 mg/kg, roughly 500 times more concentrated than the mercury in the Kiln feed. Similarly, mercury retort systems typically employ some form of mercury condensation designed for low-volume streams with high mercury vapor pressures.

The Boliden-Norzink process is used at some 50 installations around the world to recover mercury from ore roaster off-gas. These installations include gold mines as well as zinc, copper, lead, and pyrite smelters. A prominent application of this process occurs at Barrick Gold's Goldstrike Mine in northern Nevada, where some 133,000 lbs of Hg_2Cl_2 (mercurous chloride, or calomel) were reportedly recovered in 2002. An estimated 85% of the mercury recovered from gold mining in Nevada comes from Barrick, with the majority of this resulting from the Boliden-Norzink process. The process reacts aqueous $HgCl_2$ (mercuric chloride) with elemental mercury vapour (Hg^0) to form an Hg_2Cl_2 precipitate that can be captured and refined or sold to a mercury refiner. A portion of the Hg_2Cl_2 is combined with chlorine to regenerate Hg_2Cl_2 for recycle through the reactor, while the remainder is bled to the solids collection system. In evaluating this technology as a potential candidate to treat the nodulizing kiln off-gas, the kiln was assumed to replace the ore roaster as the source of high-temperature gas to be treated.

Several factors led to the conclusion that the process used at Goldstrike is technically infeasible for this application as follows:

- Gas flow rates are an order of magnitude apart. The Barrick operation combines off-gas from two roasters, each emitting 12,000 normal cubic meters (Nm^3) per hour, into a common gas treatment system. This translates to roughly 14,000 acfm, as compared to the nodulizing kiln off-gas stack flow rate of 300,000 acfm. Despite the similar ore feed rates, the Barrick roaster produces far less off-gas by utilizing oxygen rather than air, and by taking advantage of exothermic reactions in the roaster to supply a portion of the heat.

- Mercury concentrations are three orders of magnitude higher at Goldstrike. This poses issues of vessel sizing and gas-to-liquid contact ratios. The dilute concentrations of elemental mercury in the scrubbed nodulizing kiln off-gas create the potential for adding mercury to the exhaust gas (from the makeup mercuric chloride) rather than removing it.

- Temperatures would have to be lowered. Due to mercury vapor pressure concerns, the mercuric chloride scrubber at Goldstrike is operated at temperatures no higher than 40 °C. This constraint would necessitate further cooling of the nodulizing kiln off-gas.

As summarized above, the use of a mercuric chloride ($HgCl_2$) scrubber was determined to be technically infeasible because it was designed for use and has been demonstrated on exhaust gas streams from metal roasters with a flow rate of ~12,000 dscfm and an elemental Hg content of 300 mg/dscfm. In contrast, P4's air pollution control system has a flow rate of 300,000 dscfm and an elemental Hg content of 300 µg/dscfm. The scale of such equipment at P4 would be costly and beyond the designed and demonstrated capacity of commercially available mercuric chloride scrubbing technology.

The use of a mercuric chloride scrubber would also be infeasible due to differences between demonstrated conditions and P4's operations as well as potential impacts on P4's operations. In order to maximize the scrubber's efficiency, P4's off-gas would require cooling to ~100°F. This would result in a large quantity of condensed process water, the management of which would be a challenge to incorporate into the existing plant water balance.

In addition, captured mercury in the form of calomel (Hg_2Cl_2) would either need to be purged for disposal or sale, or be processed using chloride regeneration, in which liquid metallic mercury would be produced for disposal or sale. The market for and quality of both calomel and liquid metallic mercury are uncertain. In addition, the added effects of low levels of metals and sulfur compounds present in kiln exhaust are unknown, but it is likely that they would result in some mercury capture interference and issues with regenerating the scrubber fluid.

For these reasons $HgCl_2$ scrubbing and other metals refining and mercury recovery methods are eliminated from further consideration as representing MBACT for the nodulizing kiln.

3.3 *STEP 3 - RANK REMAINING CONTROL TECHNOLOGIES*

The control technologies that are carried forward for further evaluation are two conceptual control configurations. The two conceptual configurations are described below and ranked in descending order of potential control effectiveness: 50% for Conceptual Control Option 1 and 30% for Conceptual Control Option 2.

These control efficiency estimates are less than the 70% and 90% reductions reported to be achieved on coal-fired power applications using similar control techniques. This is because the properties of P4 kiln exhaust gas and respective air pollution control equipment are significantly different than those at any coal-fired power plant or other industrial facility utilizing ACI or BACI for mercury control.

The expected control efficiency for P4 would be significantly reduced due to adsorption of numerous metallic species (i.e., Cd, Zn, etc.) and sulfur containing species present in the ore and the kiln off-gas that would compete for ACI and BACI adsorption since these materials are not selective for mercury removal. These same compounds are not present in the same concentration levels in coal-fired power plant applications. Since the control efficiency of ACI and BACI have never been determined on a gas stream with comparable chemical speciation, flow rates, and temperature profile, the respective control efficiencies of 50% and 30% were determined by estimating the effect of the presence of the numerous metallic and sulfur containing species present in the ore and kiln off-gas, based on the fact that the combined average concentration of such species exceeds the average concentration of mercury by orders of magnitude.

- Conceptual Control Option 1 - Conceptual Control Option 1 is a mercury control configuration using a combination of halide injection to promote oxidation of mercury to Hg2+, gas reheat and a baghouse for ACI removal. The purpose of the gas re-heat is to achieve an optimum temperature for ACI injection and to bring the gas flow above the saturation temperature to prevent condensation in the baghouse. For the purposes of this conceptual design, ACI is evaluated because the halide injection will provide the oxidation of the mercury to the controllable Hg2+ oxidation state. The halide evaluated is calcium bromide and it would be injected in the 9 ft diameter duct. Calcium bromide ($CaBr_2$) was evaluated because it is the most common source of halide and because P4's supporting search of the RBLC and other literature did not identify other commercially available halides in use for mercury control. The gas re-heat would be achieved with an added heat exchanger downstream of the hydrosonic venturi scrubbers. Following the re-heat, ACI injection would be added with a baghouse downstream.

- Conceptual Control Option 2 - Conceptual Control Option 2 is a mercury control configuration using gas re-heat with added heat exchanger downstream of the hydrosonic venturi scrubbers, followed by BACI injection, and baghouse (no halide injection).

The following section, Step 4, presents a more detailed description of the conceptual design, and rationale in making the cost estimates used in the evaluation.

3.4 *STEP 4 - EVALUATE MOST EFFECTIVE CONTROLS*

The conceptual control options presented here are intended to provide a basis for the cost evaluation to assess the cost effectiveness of the option. Given that the control of mercury emissions from the nodulizing kiln over and above the level of control already provided by the existing air pollution control equipment is a retrofit application, the normal course of design would be to evaluate the control options through a pilot scale, slip-stream study. Such a study would establish that the control scheme works and determine important parameters for moving forward in the design process.

3.4.1 *Conceptual Control Option 1*

Under Conceptual Control Option 1, a chemical oxidant, calcium bromide, is introduced in the gas stream downstream of the spray tower and upstream of the hydrosonic venturi scrubbers (see Figure 1) in the 9 ft diameter duct. To minimize corrosion in that duct, the duct would be lined with fiber reinforced plastic. Following the hydrosonic venturi scrubbers, a heat exchanger is added to re-heat the gas to 250°F, a temperature rise of approximately 88 °F. This is above the saturation temperature of the gas; therefore, gas cooling will not result in condensation and fouling of the BACI or blinding of the fabric in the baghouse.

It is estimated that this configuration will yield some conversion of Hg^0 to Hg^{2+}, and that the ACI will capture some portion of the Hg^{2+}. This is assumed equivalent to an overall Hg removal of 50%, or 539 lbs/yr on a potential to emit basis. The assumption of 50% control is conservative because of the potential effects of gas constituents and other unknowns concerning the performance. The cost estimate is include in Appendix B1 and shows the cost of mercury removal for Conceptual Control Option 1 to be $17,200 per pound of mercury removed. This is based on a capital cost estimate for equipment and auxiliaries of $5.83 million and annualized cost of $9.3 million.

In order to compare the incremental cost benefit that would be provided by Conceptual Control Option 1 in comparison to existing controls, the estimated costs for this option were divided by the incremental change in emissions that would occur through the use of this control option. The incremental change in emissions was determined by subtracting the benefit achieved by current controls from the emission reduction that is projected to occur with Conceptual Control Option 1. This analysis is provided in Appendix B2 and shows the incremental cost of mercury removal for Conceptual Control Option 1 to be $31,900 per pound of mercury removed.

In these cost analyses, only the cost of handling and disposal of the spent ACI disposal has been incorporated in the cost estimates. The cost of regenerating the captured activated carbon containing mercury has not been included. These economic analyses therefore do not reflect the full economic impact of transferring mercury from air emissions to land discharges, including the costs of handling, transporting, stockpiling, and landfilling contaminated ACI.

This level of cost is considered to be excessive; therefore, Conceptual Control Option 1 is eliminated from further consideration as representing MBACT for the nodulizing kiln.

3.4.2 *Conceptual Control Option* 2

Conceptual Control Option 2 is the same as Conceptual Control Option 1, except that there is no halide injection. This allows for elimination of a number of line items in the capital cost estimate including the chemical storage and injection, and fiber reinforced plastic lining of the ductwork. The cost estimate is included in Appendix C1. Assuming that the BACI will provide 30% control, then 323 pounds of mercury will be controlled annually on a potential to emit basis. The assumption of 30% control is conservative because of the potential effects of gas constituents and other unknowns concerning the performance. The resulting cost of mercury controlled is $24,900 per pound of mercury removed. This is based on a capital cost estimate for equipment and auxiliaries of $5.47 million and annualized cost of $8.0 million.

In order to compare the incremental cost benefit that would be provided by Conceptual Control Option 2 in comparison to existing controls, the estimated costs for this option were divided by the incremental change in emissions that would occur through the use of this control option. The incremental change in emissions was determined by subtracting the benefit achieved by current controls from the emission reduction that is projected to occur with Conceptual Control Option 2. This analysis is provided in Appendix C2 and shows the incremental cost of mercury removal for Conceptual Control Option 2 to be $106,700 per pound of mercury removed.

Only the cost of handling and disposal of the spent ACI has been incorporated in the cost estimate. The cost of regenerating the captured activated carbon containing mercury has not been included. This economic analysis therefore does not reflect the full economic impact of transferring mercury from air emissions to land discharges, including the costs of handling, transporting, stockpiling, and landfilling contaminated ACI.

This level of cost is economically infeasible; therefore, Conceptual Control Option 2 is eliminated from further consideration as representing MBACT for the mercury emissions from the nodulizing kiln.

3.4.3 *Energy and Environmental Impacts*

The major energy impact resulting from implementation of both conceptual control options are the steam use for the reheat, the electricity to operate the additional fan, the energy for the producers to make the activated carbon, and the trucks needed for disposal of the solids removed by the baghouse (spent ACI). Both options will require 14 MWh to operate the additional fan and 5,200 Mlb/yr of steam for the reheat.

The environmental impacts from implementing both conceptual control options include the indirect air emissions from the manufacture of activated carbon, indirect air emissions from purchased electricity, direct air emissions from steam generation and the direct/indirect air emissions from the trucks needed to transport the solids removed by the baghouse (spent ACI). In addition, there are land impacts from shifting the mercury from an air emission to land disposal in a special waste landfill.

3.5 *STEP 5 - SELECT MBACT*

Based on the technology review and assessment presented in this report, there is no technically or economically feasible means of enhancing the level of mercury control already in place at the Facility. The predominant source of mercury emissions at the Facility is the nodulizing kiln. The existing air emission control system on the nodulizing kiln includes a dust bin, spray tower, and four LCDA hydrosonic venturi scrubbers. Based on mass balance results the existing air pollution control devices on the nodulizing kiln provide some amount of mercury control. It is proposed that MBACT for the nodulizing kiln is the existing control.

Emissions will be limited to 183 lbs/month on a 12-month rolling average. This emission level is based on historic mechanisms for estimating emissions including tests conducted in 2014. Compliance will be demonstrated by multiplying the monthly monitored ore throughput for the kiln by 4.92×10^{-4} lb of Hg per ton or ore processed.

4.0 *SUMMARY*

This MBACT review presents information concerning control of mercury emission from sources at the Facility. Based on the mercury emission inventory for the Facility (see Table 1), it is determined that the nodulizing kiln is the source of approximately 99.6% of the emissions at the Facility. A 5-step review process recommended by USEPA for BACT review is applied to the nodulizing kiln mercury emissions. Through the 5-step MBACT review process six general control technology categories were identified and evaluated. Two control options were evaluated for cost effectiveness on a conceptual design basis including the following:

- Conceptual Control Option 1 - Halide injection with ACI (see Section 3.3 for more detail), and

- Conceptual Control Option 2 – BACI (see Section 3.3 for more detail).

These options are excluded as not economically feasible; therefore, it is demonstrated that there is no technically or economically feasible means of controlling the mercury emissions from the nodulizing kiln over and above the level provided by existing air pollution control technology. It is proposed that MBACT for the nodulizing kiln is the existing control.

Emissions will be limited to 183 lbs/month on a 12-month rolling average. This emission level is based on historic mechanisms for estimating emissions including tests conducted in 2014. Compliance will be demonstrated by multiplying the monthly monitored ore throughput for the kiln by 4.92×10^{-4} lb of Hg per ton of ore processed.

Appendix A
RBLC Search Results

Facility/Fuel *Miscellaneous Source Categories*	*State*	*Date of Permit Issuance*	*Technology*	*Limit*
Republic Steel - Electric Arc Furnace	*OH*	*7/18/2012*	*Direct-Shell Evacuation Control system with adjustable air gap and water-cooled elbow and duct to Baghouse*	*0.0000045 gr/dscf* *0.15 T/YR*
Suwannee Mill - Two (2) Biomass-Fuel Boilers - 120 MMBtu/hr each	*FL*	*9/5/2012*	*Efficient combustion practice*	*March 21, 2011 final version of NESAHP Subpart DDDDD (An alternative NESHAP limit is 0.25 lb/MMBtu of steam output). December 23, 2011 version of NESHAP Subpart DDDDD if it becomes final and effective (An alternative NESHAP limit is 3.4x10-6 lb/MMBtu of steam output). Current NESAHP Subpart DDDDD is higher than 3.4x10-6 lb/MMBtu of steam output.*
PINELLAS COUNTY RES RECOVERY FACILITY - Three(3) Municipal Waste Combustors	*FL*	*11/19/2012*	*Activated Carbon Injection*	*50.0000 MG/DSCM @7% O2*
American Municipal Power Generating Station - PC boiler	*OH*	*11/06/09*	*Sorbent/AC Injection*	*1.4 lb/Tbtu*
Mahoning Renewable Energy – Waste Combustor	*OH*	*1/07/10*	*ACI/FF*	*0.14 ton/yr*
Ohio River Clean Fuels: F-T Catalyst Rotary Dryer - gas	*OH*	*2/20/09*	*None*	*43.45 lb/yr*
John W. Kirk Jr. Power Plant	*AR*	*1/22/09*	*ACI*	*1.7 lb/Tbtu*
Tate and Lyle Ingredients America, Inc. – corn fiber	*IA*	*1/30/09*	*SDA/SCR/FF*	*0 lb/mmbtu*
Ripley Heating Plant CFB boiler – wood and coal	*MI*	*8/04/08*	*FF*	*0 lb/mmbtu*
New Steel International, Inc., Haverhill – PC boiler	*OH*	*2/09/10*	*None*	*0.0014 lb/hr*
New Steel International, Inc., Haverhill – Rotary hearth furnace	*OH*	*2/9/10*	*None*	*0.0014 lb/hr*
New Steel International, Inc., Haverhill – Electric arc furnace	*OH*	*2/9/10*	*Lignite injection*	*0.0066 lb/hr*
New Steel International, Inc, Haverhill – Ladel metallurgy furnace	*OH*	*2/9/10*	*Lignite injection*	*0.0066 lb/hr*
Dry Fork Station – PC boiler	*WY*	*4/20/09*	*ACI*	*0.0001 lb/Mwh*
Spiritwood Station CFB – coal/lignite	*ND*	*3/27/08*	*ACI/Baghouse*	*0.0002 lb/Mwh*

Homeland Energy Solutions, LLC	IA	7/21/08	None	0.0094 lb/hr
North Brooksville Cement Plant – kiln	FL	4/21/09	None	41 ug/dscm
Sunnyside Ethanol, LLC – CFB boiler	PA	8/12/08	Limestone injection/FF	2.1 lb/hr
Hillsborough County Resource Recovery Facility -	FL	8/01/08	ACI	28 ug/dscm
Cargill, Inc. CFB boiler - coal	NE	2/13/07	Sorbent injection	0 lb/hr
Dallman Power Plant – coal	IL	1/08/09	SCR, scrubber, wet ESP, or sorbent injection	95% control
Sandy Creek Energy Station – PC boiler	TX	11/08/07	None	0.94 lb/hr
South Point Biomass Generation – wood fired boiler	OH	8/16/07	Baghouse	0.013 ton/yr
Branford Cement Plant - kiln	FL	3/03/06	Material balance	117.5 lb/yr
American Cement Company – kiln	FL	1/31/07	None	122 lb/yr
Sumter/Center Hill Cement Plant – kiln	FL	10/02/07	None	184 lb/yr
City Public Service JK Spruce Electric Generating Unit 2 – gas turbine	TX	11/20/07	None	0.43 lb/hr
North Star BHP Steel, LTD – Electric arc furnace	OH	5/24/07	Baghouse	0.095 lb/hr
City of Harrisburg Resource Recovery Facility – solid waste combustor	VA	8/23/06	Dry FGD using hydrated lime	0.08 mg/dscm
Texas Genco W.A. Parish Unit 8 – PC boiler	TX	4/28/09	None	1.71 lb/hr
Texas Genco W.A. Parish – coal and gas fired stack	TX	6/04/09	None	2.13 lb/hr
Republic Engineered Products, Inc. – electric arc furnace	OH	5/08/07	None	0.061 lb/hr
Nucor Steel Marion, Inc. – electric arc furnace stack emissions	OH	5/08/07	None	0.063 lb/hr
Nucor Steel Marion, Inc. – electric arc furnace fugitive emissions	OH	5/08/07	Segmented canopy hood, scavenger ducting, etc.	0.0025 ton/yr
River Hill Power Company, LLC – waste coal CFB	PA	9/17/07	None	17.4 lb/yr
Green Energy Resource Recovery Project – waste coal CFB	PA	6/26/08	None	20.05 lb/hr
Dow Chemical Plant B and Oyster Creek Light Hydrocarbons Plant – hydrocarbon fuel	TX	5/27/07	None	0.01 lb/hr
Auburn Nugget – gas fired rotary hearth steel furnace	IN	8/23/06	Wet scrubber	0.05 lb/hr
Wheeling Pittsburgh Steel Corporation – oxygen furnace	OH	7/06/05	None	0.0003 lb/hr
Wheeling Pittsburgh Steel Corporation – oxygen furnace	OH	7/06/05	None	0.056 lb/hr
Wheeling Pittsburgh Steel Corporation – electric arc furnace	OH	7/06/05	None	0.119 lb/hr
Brooksville Cement Plant – kiln	FL	7/29/05	Material balance	122 lb/yr

City Utilities of Springfield, Southwest Power Station – PC boiler	*MO*	*7/19/06*	*None*	*0.09 ton/yr*
Dow Texas Operations Freeport – gas fired combined cycle	*TX*	*4/20/06*	*None*	*0.001 lb/hr*
Dow Texas Operations Freeport – gas turbines	*TX*	*4/20/06*	*None*	*0.001 lb/hr*
Shiller Station – waste wood boiler	*NH*	*11/05/04*	*SNCR with FF*	*3 lb/Tbtu*
WPS-Weston Plant – PC boiler	*WI*	*3/06/06*	*FF/Sorbent injection study*	*1.7 lb/Tbtu*
WPS-Weston Plant – natural gas boiler	*WI*	*3/06/06*	*Natural gas*	*0.0001 lb/hr*
WPS-Weston Plant – diesel booster plant	*WI*	*3/06/06*	*Good combustion*	*0 lb/hr*
WPS-Weston Plant – diesel fire pump	*WI*	*3/06/06*	*Good combustion*	*0 lb/hr*
WPS-Weston Plant – natural gas station heater	*WI*	*3/06/06*	*Natural gas*	*0 lb/hr*
Fritz Enterprises – coke fired aluminum and iron production	*MI*	*11/22/04*	*Scrap mgt. plan*	*35 lb/yr*
Intermountain Power Generation Unit 3 – PC boiler	*Utah*	*2/02/06*	*SCR, Wet FGD, FF*	*0 lb/MW-hr*
Sevier Power Company – coal fired CFB boiler	*Utah*	*2/1/06*	*Dry lime scrubber, FF*	*0 lb/MMbtu*
PSI Energy, Madison Station – gas fired combined cycle	*OH*	*6/20/05*	*None*	*0.0023 ton/yr*
FDS Coke – coke oven batteries	*OH*	*3/13/06*	*ACI*	*0.0006 lb/hr*
FDS Coke – coal fired HRSG bypass	*OH*	*3/13/06*	*None*	*0.081 lb/hr*
Charter Steel – electric arc furnace	*OH*	*6/20/05*	*Limit Hg in scrap*	*0.052 lb/hr*
Maidsville – PC boiler	*WV*	*8/10/05*	*SCR, dry solid injection w/ FF, wet limestone forced oxidation*	*0.0146 lb/hr*
Santee Cooper Cross Generating Station – PC boiler	*SC*	*7/01/04*	*SCR, FGD, ESP, LNB*	*3.6 lb/Tbtu*
SMI Texas – steel mini-mill	*TX*	*12/28/05*	*None*	*0.0005 lb/hr*
SMI Texas – melt shop ventilation	*TX*	*12/28/05*	*None*	*0.0001 lb/hr*
SMI Texas – melt shop roof vent	*TX*	*12/28/05*	*None*	*0.0002 lb/hr*
SMI Texas – melt shop wall vent	*TX*	*12/28/05*	*None*	*0 lb/hr*
SMI Texas – east/west castor pray chamber stack	*TX*	*12/28/05*	*None*	*0 lb/hr*
SMI Texas – shredder/separator fabric filter stack	*TX*	*12/28/05*	*None*	*0 lb/hr*
SMI Texas – hammer mill	*TX*	*12/28/05*	*Water flood*	*0.0001 lb/hr*
Biomass Energy LLC, Southpoint Power – wood fired boiler	*OH*	*4/25/03*	*None*	*0.013 ton/yr*
Haverville North Coke Company – coke gas fired HRSG	*OH*	*4/25/07*	*Bypass to controls*	*0.008 lb/hr*
Macsteel Division – electric arc furnace	*MI*	*10/13/05*	*Baghouse*	*0.069 ton/yr*
WA Parish Electric Generating Station – PC boiler	*TX*	*8/06/03*	*None*	*2.13 lb/hr*
WA Parish Electric Generating Station – PC boiler	*TX*	*8/06/03*	*None*	*1.86 lb/hr*

Lee County Waste-to-Energy Facility – municipal waste combustor	FL	12/10/03	ACI	0.028 mg/dscm
MidAmerican Energy Company – PC boiler	IA	7/22/03	ACI	0 lb/MMbtu
Harrisonburg Resource Rec. – municipal waste combustor	VA	3/04/04	None	0.08 mg/dscm
Harrisonburg Resource Rec. – municipal waste combustor	VA	5/12/03	ACI and good combustion	0.08 mg/dscm
The Timken Company, Faircrest Plant – gas fired annealing furnace	OH	2/20/03	None	0.0037 lb/hr
Washington Parish Electric Generating Station – PC boiler	TX	9/02/03	None	2.13 lb/hr
Washington Parish Electric Generating Station – PC boiler	TX	9/02/03	None	1.86 lb/hr
Thoroughbred Generating Station – PC boiler	KY	4/28/04	ESP, WESP, WFGD	3.21 lb/Tbtu
East Kentucky Power Coop, Spurlock Power Station – coal fired CFB boiler	KY	5/12/04	Baghouse	2.65 lb/Tbtu
Lima Energy Company – syngas fired combined cycle	OH	4/24/03	None	0.0013 lb/hr
Camden Resource Recovery Facility – waste incinerators	NJ	3/22/02	ESP, scrubber	0.31 lb/hr
Meadwestvaco Kentucky, Inc./Wickliffe – pulp and paper mill recovery furnace	KY	5/12/04	None	3200 g/day
Riley Energy Systems of Lisbon Corp. – municipal waste combustors	CT	11/21/01	ACI/FF	0.165 lb/hr
Minergy Detroit LLC – sludge incinerator	MI	5/20/02	Quench, ACI/FF	0.0197 lb/hr
Dow Chemical – rotary kiln waste incinerator	MI	6/06/02	Venturi and feed rate limit	0.13 mg/dscm
Kentucky Pioneer Energy LLC – Trap – syngas fired combined cycle	KY	4/21/04	None	0.08 mg/dscm
Limestone Electric Generating Station – PC boiler	TX	8/08/03	None	0.4 lb/hr
Kentucky Mountain Power – coal fired CFB boiler	KY	4/19/04	Baghouse	81 lb/Tbtu
W.A. Parish Electric Generating Station – PC boiler	TX	12/30/02	None	1.17 lb/hr
Dade County Resource Recovery Facility – municipal waste combustor	FL	10/11/00	ACI	0.08 ton/yr
Chapparral Steel Midlothian Steel Mill – melt shop overhead canopy hoods A	TX	8/08/03	None	0.0031 lb/hr
Chapparral Steel Midlothian Steel Mill – melt shop overhead canopy hoods B	TX	8/08/03	None	0.0053 lb/hr
Chapparral Steel Midlothian Steel Mill – furnace evacuation system	TX	8/08/03	None	0.11 lb/hr

Source Category 90.028				
Cemex Cement Inc., North Brooksville Cement Plant	*FL*	*6/27/07*	*not listed*	*190 lb/yr*
Suwanne American Cement, Branford Cement Plant (Suwanne)	*FL*	*3/30/06*	*not listed*	*117.5 lb/yr*
American Cement Company LLC, American Cement Company	*FL*	*2/10/06*	*not listed*	*122 lb/yr*
Sumter Cement Company LLC, Sumter/Center Hill Cement Plant	*FL*	*2/7/06*	*not listed*	*184 lb/yr*
Florida Crushed Stone Company, Brooksville Cement Plant (FCS)	*FL*	*12/20/04*	*not listed*	*122 lb/yr*
Source Category 21.400				
Department of Solid Waste Management, Hillsborough County Resource Recovery Facility	*FL*	*11/3/06*	*ACI*	*28 µg/dscm*
City of Harrisonburg, City of Harrisonburg Resource Recovery Facility	*VA*	*11/18/05*	*scrubber*	*80 µg/dscm*
Lee County Solid Waste Division, Lee County Waste-To- Energy Facility	*FL*	*10/13/03*	*ACI*	*28 µg/dscm*
City of Harrisonburg, Harrisonburg Resource Rec.	*VA*	*3/25/03*	*none*	*80 µg/dscm*
City of Harrisonburg, Harrisonburg Resource Recovery Facility	*VA*	*3/24/03*	*ACI and good combustion*	*80 µg/dscm*
Camden County Resource Recovery Facility, Camden Resource Recovery Facility	*NJ*	*3/22/02*	*ESP and scrubber*	*0.005 lb/ton of waste incinerated*
Riley Energy Systems of Lisbon Corp., Riley Energy Systems of Lisbon Corp	*CT*	*11/21/01*	*ACl and fabric filter*	*0.165 lb/hr*
Dade County Dept. of Solid Waste Management, Dade County Resource Recovery Facility	*FL*	*7/21/00*	*ACl*	*70 µg/dscm*
Wheelabrator, Wheelabrator South Broward, Inc.	*FL*	*9/28/99*	*source separation of mercury*	*0.019 lb/hr (based on 70 µg/dscm)*
Wheelabrator, Wheelabrator North South Broward	*FL*	*9/28/99*	*source separation of mercury*	*70 µg/dscm*

Appendix B
Cost Spreadsheets for Conceptual Control Option 1

Appendix B1

P4 Production, L.L.C. - Hg BACT Analysis

Conceptual Control Option 1

[Includes oxidant injection (CaBr2) and BACI]

Nodulizing Kiln

Control Efficiency (%)	50.0

Facility Input Data

Item	Value
Operating Schedule	
Shifts per day	3
Hours per day	24
Days per week	7
Total Hours per year	8760
Economic Life, years	10
Interest Rate (%)	7
Source(s) Controlled	Nodulizer Kiln
Total Flowrate (acfm)	300,000
Hg from Kiln Operation (lb/hr)	0.123
Hg from Kiln Operation (lb/yr)	1,078
Site Specific Electricity Cost ($/kWh)	0.043
Site Specific Operating Labor Cost ($/hr)	$45.00
Site Specific Maint. Labor Cost ($/hr)	$45.00

Capital Costs

	Value	Basis
Direct Costs		
1.) Purchased Equipment Cost		
a.) Equipment cost + auxiliaries	$5,831,789	See Capital Cost Estimate, A
b.) Instrumentation	$0	Included
c.) Sales taxes	$0	Included
d.) Freight	$291,589	0.05 X A
Total Purchased equipment cost, (PEC)	$6,123,379	B
2.) Direct installation costs		
a.) Foundations and supports	$306,200	0.10 x B
b.) Handling and erection	$1,224,700	0.20 x B
c.) Electrical	$61,200	0.01 x B
d.) Piping	$61,200	0.01 x B
e.) Insulation for ductwork & painting	$61,200	0.01 x B
f.) Stack modification	$122,500	0.02 x B
Total direct installation cost	$1,837,014	0.30 x B
3.) Site preparation	$200,000	As Required, SP
4.) Buildings	NA	As Required, Bldg.
Total Direct Cost, DC	$8,160,400	1.30B + SP + Bldg.
Indirect Costs (installation)		
5.) Engineering	$122,500	0.02 x B
6.) Construction and field expenses	$306,200	0.05 x B
7.) Contractor fees	$612,300	0.10 x B
8.) Start-up	$122,500	0.02 x B
9.) Performance test	$61,200	0.01 x B
10.) Contingencies	$918,500	0.15 x B
Total Indirect Cost, IC	$2,143,200	0.35 x B + Other
Total Capital Investment (TCI) = DC + IC	$10,303,600	1.61B + SP + Bldg. + Other

Annual Costs

Annual Costs

Item	Value	Basis	Source
1) Electricity			Estimate
Fan Power Requirement (kW)	1,648		
Electric Power Cost ($/kWh)	0.043		
Cost ($/yr)	$620,756		
2) Operating Costs			Estimate
Operating Labor Requirement (hr/shift)	1	1 hour per shift	
Unit Cost ($/hr)	$40.00	Facility Data	
Labor Cost ($/yr)	$43,680		
3) $CaBr_2$ Cost ($/gal)	9.00		Estimate
Hourly Requirerment (gal/hour)	14	Based on CaBr2:ACI ratio of 0.15	
Annual requirement (gal/year)	118,260		
Total NaOCl Costs ($/year)	$1,064,340		
4) Steam Reheat			Estimate
Temperature rise (°F)	88		
Steam requirement (klb/hr)	59		
Steam cost ($/klb)	$9.0	Estimated	
Total Cost	$4,651,560		
5) BAC Cost ($/lb)	$1		Estimate
Hourly Requirerment (Lbs/hour)	90	5 lb/MMacfm	
Annual requirement (Lbs/year)	788,400		
Total BAC Costs ($/year)	$788,400		
6) Residual Disposal			Esitamte
Annual Quantity (TPY)	434		
Cost ($/T)	$200	Special Waste Assumed	
Total Disposal Cost ($/year)	$86,724		
Total Operating Costs	**$7,255,460**		
7) Supervisory Labor			OAQPS
Cost ($/yr)	$6,550	15% Operating Labor	
8) Maintenance			
Maintenance Labor Req. (hr/year)	876.0	10% Operating Hours	Estimate
Unit Cost ($/hr)	$45.00	Facility Data	Estimate
Labor Cost ($/yr)	$39,420		
Material Cost ($/yr)	$39,420	100% of Maintenance Labor	OAQPS
Total Cost ($/yr)	$78,840		
9) Indirect Annual Costs			
Overhead	$77,440	60% of O&M Costs	OAQPS
Administration	$206,070	2% of Total Capital Investment	OAQPS
Property Tax	$103,040	1% of Total Capital Investment	OAQPS
Insurance	$103,040	1% of Total Capital Investment	OAQPS
Capital Recovery	$1,467,000	10 yr life; 7% interest	OAQPS
Total Indirect ($/yr)	$1,956,590		
Total Annualized Cost ($/yr)	**$9,297,400**		
Total Controlled (lb/yr)	**539.0**		
Cost Effectiveness ($/lb)	**$17,200**		

Appendix B2
P4 Production, L.L.C. - Hg BACT Analysis
Conceptual Control Option 1 (Incremental Costs)
[Includes oxidant injection (CaBr2) and BACI]
Nodulizing Kiln

Control Efficiency (%)	50.0

Facility Input Data

Item	Value
Operating Schedule	
Shifts per day	3
Hours per day	24
Days per week	7
Total Hours per year	8760
Economic Life, years	10
Interest Rate (%)	7
Source(s) Controlled	Nodulizer Kiln
Total Flowrate (acfm)	300,000
Hg from Kiln Operation (lb/hr)	0.123
Hg from Kiln Operation (lb/yr)	1,078
Site Specific Electricity Cost ($/kWh)	0.043
Site Specific Operating Labor Cost ($/hr)	$45.00
Site Specific Maint. Labor Cost ($/hr)	$45.00

Capital Costs

	Value	Basis
Direct Costs		
1.) Purchased Equipment Cost		
a.) Equipment cost + auxiliaries	$5,831,789	See Capital Cost Estimate, A
b.) Instrumentation	$0	Included
c.) Sales taxes	$0	Included
d.) Freight	$291,589	0.05 X A
Total Purchased equipment cost, (PEC)	$6,123,379	B
2.) Direct installation costs		
a.) Foundations and supports	$306,200	0.10 x B
b.) Handling and erection	$1,224,700	0.20 x B
c.) Electrical	$61,200	0.01 x B
d.) Piping	$61,200	0.01 x B
e.) Insulation for ductwork & painting	$61,200	0.01 x B
f.) Stack modification	$122,500	0.02 x B
Total direct installation cost	$1,837,014	0.30 x B
3.) Site preparation	$200,000	As Required, SP
4.) Buildings	NA	As Required, Bldg.
Total Direct Cost, DC	$8,160,400	1.30B + SP + Bldg.
Indirect Costs (installation)		
5.) Engineering	$122,500	0.02 x B
6.) Construction and field expenses	$306,200	0.05 x B
7.) Contractor fees	$612,300	0.10 x B
8.) Start-up	$122,500	0.02 x B
9.) Performance test	$61,200	0.01 x B
10.) Contingencies	$918,500	0.15 x B
Total Indirect Cost, IC	$2,143,200	0.35 x B + Other
Total Capital Investment (TCI) = DC + IC	**$10,303,600**	**1.61B + SP + Bldg. + Other**

Annual Costs

Item	Value	Basis	Source
1) Electricity			Estimate
Fan Power Requirement (kW)	1,648		
Electric Power Cost ($/kWh)	0.043		
Cost ($/yr)	$620,756		
2) Operating Costs			Estimate
Operating Labor Requirement (hr/shift)	1	1 hour per shift	
Unit Cost ($/hr)	$40.00	Facility Data	
Labor Cost ($/yr)	$43,680		
3) $CaBr_2$ Cost ($/gal)	9.00		Estimate
Hourly Requirerment (gal/hour)	14	Based on CaBr2:ACI ratio of 0.15	
Annual requirement (gal/year)	118,260		
Total NaOCl Costs ($/year)	$1,064,340		
4) Steam Reheat			Estimate
Temperature rise (°F)	88		
Steam requirement (klb/hr)	59		
Steam cost ($/klb)	$9.0	Estimated	
Total Cost	$4,651,560		
5) BAC Cost ($/lb)	$1		Estimate
Hourly Requirerment (Lbs/hour)	90	5 lb/MMacfm	
Annual requirement (Lbs/year)	788,400		
Total BAC Costs ($/year)	$788,400		
6) Residual Disposal			Esitamte
Annual Quantity (TPY)	434		
Cost ($/T)	$200	Special Waste Assumed	
Total Disposal Cost ($/year)	$86,724		
Total Operating Costs	**$7,255,460**		
7) Supervisory Labor			OAQPS
Cost ($/yr)	$6,550	15% Operating Labor	
8) Maintenance			
Maintenance Labor Req. (hr/year)	876.0	10% Operating Hours	Estimate
Unit Cost ($/hr)	$45.00	Facility Data	Estimate
Labor Cost ($/yr)	$39,420		
Material Cost ($/yr)	$39,420	100% of Maintenance Labor	OAQPS
Total Cost ($/yr)	$78,840		
9) Indirect Annual Costs			
Overhead	$77,440	60% of O&M Costs	OAQPS
Administration	$206,070	2% of Total Capital Investment	OAQPS
Property Tax	$103,040	1% of Total Capital Investment	OAQPS
Insurance	$103,040	1% of Total Capital Investment	OAQPS
Capital Recovery	$1,467,000	10 yr life; 7% interest	OAQPS
Total Indirect ($/yr)	$1,956,590		
Total Annualized Cost ($/yr)	**$9,297,400**		
Total Controlled (lb/yr), above current controls	**291.1**		
Cost Effectiveness ($/lb)	**$31,900**		

Appendix C
Cost Spreadsheets for Conceptual Control Option 2

Appendix C

P4 Production, L.L.C. - Hg BACT Analysis

Conceptual Control Option 2

[Does not Include oxidant injection ($CaBr_2$); BACI only]

Nodulizing Kiln

Control Efficiency (%)	30.0

Facility Input Data

Item	Value
Operating Schedule	
Shifts per day	3
Hours per day	24
Days per week	7
Total Hours per year	8760
Economic Life, years	10
Interest Rate (%)	7
Source(s) Controlled	Nodulizer Kiln
Total Flow rate (acfm)	300,000
Hg from Kiln Operation (lb/hr)	0.123
Hg from Kiln Operation (lb/yr)	1,078
Site Specific Electricity Cost ($/kWh)	0.043
Site Specific Operating Labor Cost ($/hr)	$45.00
Site Specific Maint. Labor Cost ($/hr)	$45.00

Capital Costs

	Value	Basis
Direct Costs		
1.) Purchased Equipment Cost		
a.) Equipment cost + auxiliaries	$5,467,687	See Capital Cost Estimate, A
b.) Instrumentation	$0	Included
c.) Sales taxes	$0	Included
d.) Freight	$273,384	0.05 X A
Total Purchased equipment cost, (PEC)	$5,741,072	B
2.) Direct installation costs		
a.) Foundations and supports	$287,100	0.10 x B
b.) Handling and erection	$1,148,200	0.20 x B
c.) Electrical	$57,400	0.01 x B
d.) Piping	$57,400	0.01 x B
e.) Insulation for ductwork & painting	$57,400	0.01 x B
f.) Stack modification	$114,800	0.02 x B
Total direct installation cost	$1,722,321	0.30 x B
3.) Site preparation	$200,000	As Required, SP
4.) Buildings	NA	As Required, Bldg.
Total Direct Cost, DC	$7,663,400	1.30B + SP + Bldg.
Indirect Costs (installation)		
5.) Engineering	$114,800	0.02 x B
6.) Construction and field expenses	$287,100	0.05 x B
7.) Contractor fees	$574,100	0.10 x B
8.) Start-up	$114,800	0.02 x B
9.) Performance test	$57,400	0.01 x B
10.) Contingencies	$861,200	0.15 x B
Total Indirect Cost, IC	$2,009,400	0.35 x B + Other
Total Capital Investment (TCI) = DC + IC	**$9,672,800**	**1.61B + SP + Bldg. + Other**

Annual Costs

Item	Value	Basis	Source
1) Electricity			Estimate
Fan Power Requirement (kW)	1,648		
Electric Power Cost ($/kWh)	0.043		
Cost ($/yr)	$620,756		
2) Operating Costs			Estimate
Operating Labor Requirement (hr/shift)	1	1 hour per shift	
Unit Cost ($/hr)	$40.00	Facility Data	
Labor Cost ($/yr)	$43,680		
3) Steam Reheat			Estimate
Temperature rise (°F)	88		
Steam requirement (klb/hr)	59		
Steam cost ($/klb)	$9.0	Estimated	
Total Cost	$4,651,560		
4) BAC Cost ($/lb)	$1		Estimate
Hourly Requirerment (Lbs/hour)	90	5 lb/MMacfm	
Annual requirement (Lbs/year)	788,400		
Total BAC Costs ($/year)	$788,400		
5) Residual Disposal			Esitamte
Annual Quantity (TPY)	434		
Cost ($/T)	$200	Special Waste Assumed	
Total Disposal Cost ($/year)	$86,724		
Total Operating Costs	**$6,191,120**		
6) Supervisory Labor			OAQPS
Cost ($/yr)	$6,550	15% Operating Labor	
7) Maintenance			
Maintenance Labor Req. (hr/year)	438.0	5% Operating Hours	Estimate
Unit Cost ($/hr)	$45.00	Facility Data	Estimate
Labor Cost ($/yr)	$19,710		
Material Cost ($/yr)	$19,710	100% of Maintenance Labor	OAQPS
Total Cost ($/yr)	$39,420		
8) Indirect Annual Costs			
Overhead	$53,790	60% of O&M Costs	OAQPS
Administration	$193,460	2% of Total Capital Investment	OAQPS
Property Tax	$96,730	1% of Total Capital Investment	OAQPS
Insurance	$96,730	1% of Total Capital Investment	OAQPS
Capital Recovery	$1,377,190	10 yr life; 7% interest	OAQPS
Total Indirect ($/yr)	$1,817,900		
Total Annualized Cost ($/yr)	**$8,055,000**		
Total Controlled (lb/yr)	**323.4**		
Cost Effectiveness ($/lb)	**$24,900**		

Appendix C2

P4 Production, L.L.C. - Hg BACT Analysis

Conceptual Control Option 2 (Incremental Costs)

[Does not Include oxidant injection (CaBr2); BACI only]

Nodulizing Kiln

Control Efficiency (%)	30.0

Facility Input Data

Item	Value
Operating Schedule	
Shifts per day	3
Hours per day	24
Days per week	7
Total Hours per year	8760
Economic Life, years	10
Interest Rate (%)	7
Source(s) Controlled	Nodulizer Kiln
Total Flowrate (acfm)	300,000
Hg from Kiln Operation (lb/hr)	0.123
Hg from Kiln Operation (lb/yr)	1,078
Site Specific Electricity Cost ($/kWh)	0.043
Site Specific Operating Labor Cost ($/hr)	$45.00
Site Specific Maint. Labor Cost ($/hr)	$45.00

Capital Costs

	Value	Basis
Direct Costs		
1.) Purchased Equipment Cost		
a.) Equipment cost + auxiliaries	$5,467,687	See Capital Cost Estimate, A
b.) Instrumentation	$0	Included
c.) Sales taxes	$0	Included
d.) Freight	$273,384	0.05 X A
Total Purchased equipment cost, (PEC)	$5,741,072	B
2.) Direct installation costs		
a.) Foundations and supports	$287,100	0.10 x B
b.) Handling and erection	$1,148,200	0.20 x B
c.) Electrical	$57,400	0.01 x B
d.) Piping	$57,400	0.01 x B
e.) Insulation for ductwork & painting	$57,400	0.01 x B
f.) Stack modification	$114,800	0.02 x B
Total direct installation cost	$1,722,321	0.30 x B
3.) Site preparation	$200,000	As Required, SP
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Total Direct Cost, DC	$7,663,400	1.30B + SP + Bldg.
Indirect Costs (installation)		
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6.) Construction and field expenses	$287,100	0.05 x B
7.) Contractor fees	$574,100	0.10 x B
8.) Start-up	$114,800	0.02 x B
9.) Performance test	$57,400	0.01 x B
10.) Contingencies	$861,200	0.15 x B
Total Indirect Cost, IC	$2,009,400	0.35 x B + Other
Total Capital Investment (TCI) = DC + IC	**$9,672,800**	**1.61B + SP + Bldg. + Other**

Annual Costs

Item	Value	Basis	Source
1) Electricity			Estimate
Fan Power Requirement (kW)	1,648		
Electric Power Cost ($/kWh)	0.043		
Cost ($/yr)	$620,756		
2) Operating Costs			Estimate
Operating Labor Requirement (hr/shift)	1	1 hour per shift	
Unit Cost ($/hr)	$40.00	Facility Data	
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Total BAC Costs ($/year)	$788,400		
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Annual Quantity (TPY)	434		
Cost ($/T)	$200	Special Waste Assumed	
Total Disposal Cost ($/year)	$86,724		
Total Operating Costs	**$6,191,120**		
6) Supervisory Labor			OAQPS
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Unit Cost ($/hr)	$45.00	Facility Data	Estimate
Labor Cost ($/yr)	$19,710		
Material Cost ($/yr)	$19,710	100% of Maintenance Labor	OAQPS
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Property Tax	$96,730	1% of Total Capital Investment	OAQPS
Insurance	$96,730	1% of Total Capital Investment	OAQPS
Capital Recovery	$1,377,190	10 yr life; 7% interest	OAQPS
Total Indirect ($/yr)	$1,817,900		
Total Annualized Cost ($/yr)	**$8,055,000**		
Total Controlled (lb/yr), above current controls	**75.5**		
Cost Effectiveness ($/lb)	**$106,700**		

P4 Production, L.L.C. Elemental Phosphorus Plant
Soda Springs, Idaho
Mercury Emissions
Preliminary Assessment of Local Impacts

1.0 INTRODUCTION

P4 Production, L.L.C. (P4) owns and operates an elemental phosphorous production facility near Soda Springs, Idaho. The facility processes phosphate ore to produce elemental phosphorus (P4) for sale. In the course of processing the ore, trace amounts of mercury are emitted to the atmosphere.

P4 is currently updating their 2012 Mercury Best Available Control Technology (BACT) determination and as part of that determination, has requested ERM's expert judgment of the environmental impact of their facility's mercury emissions on the local environment in Idaho.

2.0 BACKGROUND

A conservative estimate of P4's annual mercury emissions is 1,100 pounds, after emission controls. Recent source testing determined that 93 to 97 percent of the mercury is in gaseous, elemental form.

The impact of another nearby Idaho mercury emission source, a calciner at the Idaho National Engineering and Environmental Laboratory (INEEL), has been studied and reported by M.L. Abbott and D.D. Susong[1]. Comparing Soda Springs' mercury emissions with those from the INEEL facility show significant differences in the chemical speciation. INEEL measurements found the mercury emissions to be almost exclusively oxidized mercury compounds—in both gaseous and solid phases. Abbott and Susong estimated that elemental mercury emissions from INEEL are negligible.

In 2008, ICF International reported their findings of a mercury modeling study[2] performed for U.S. EPA's Watershed Branch of the Office of Wetlands, Oceans, and Watersheds. This study includes results for Idaho and included P4's emissions and modeled impacts. The study was performed in support of the Agency's surface water Total Maximum Daily Load (TMDL) program.

[1] Abbott, M.L. and Susong, D.D., *Mercury in soil near a long-term air emission source in southeaster Idaho*, Environmental Geology, 43:353-356, 2003.

[2] ICF International, *Model-based analysis and tracking of airborne mercury emissions to assist in watershed planning*, http://www.epa.gov/owow/tmdl/pdf/final300report_10072008.pdf, August 2008.

In his review presentation to the Board of Environmental Quality, Idaho Department of Environmental Quality[3], Dr. Steve Lindberg critiqued ICF's conclusions as they apply to Idaho in general, and particularly in respect to industrial emissions—including those from P4. In that presentation, Lindberg concluded that ICF's results for Idaho were fatally flawed due to the study's reliance on obsolete and inaccurate mercury emissions and speciation data, and a model that was not representative of mercury's terrestrial cycling in the arid West.

3.0 PRELIMINARY ASSESSMENT

The chemical form and physical state in which mercury enters the atmosphere largely determine how and when it deposits, becoming available for biogeological cycling[4].

Elemental mercury. Elemental mercury, Hg(0) is emitted in gaseous form. Mercury inhalation only poses a human health threat at very high, occupational exposure levels[5]. Elemental mercury is relatively stable in the atmosphere and is expected to remain in its gaseous elemental form in the atmosphere for approximately one year[4].

The approximately 1023 pounds per year of Hg(0) emitted from the P4 facility joins the estimated 11,000,000 pound world-wide atmospheric mercury burden[6] and will, ultimately, return to the terrestrial environment. The likely impact of the P4 facility's Hg(0) emissions at any location in Idaho would undoubtedly be negligible since the emissions are expected to remain in a gaseous state for approximately one year, resulting in these emissions being broadly dispersed throughout the globe with little deposition near the plant.

Oxidized mercury. Oxidized divalent mercury species, Hg(II) are either gaseous (often referred to as Reactive Gaseous Mercury, RGM) or particulate (e.g., mercuric chloride). These compounds tend to be reactive, water soluble, or both. This leads to fairly short atmospheric lifetimes, with deposition fairly close to their source. P4 operations are conservatively estimated to emit 77 pounds of Hg(II) to the atmosphere per year. By comparison, INEEL emitted about 200 pounds of Hg(II) during operation of its calciner—roughly three times that of the P4 facility.

Organic mercury. The greatest ecological impact from mercury occurs when it enters the terrestrial and aquatic ecosystems and undergoes microorganism conversion to organic compounds (e.g., methyl mercury) which are biologically available. Organic mercury tends to be

---

[3] Lindberg, Steve, *Pathways of mercury (Hg) in Idaho waterways*, presentation to the Board of Environmental Quality, Idaho Department of Environmental Quality, February 12, 2009.
[4] Osa, R.H., ed., Electric Power Research Institute 1000632, *Mercury source-receptor relationships expert panel*, October 2000.
[5] Osa, R.H., *Mercury Toxicity*, presented at the Air and Waste Management Association "Mercury in the Environment" Specialty Conference, Minneapolis-St. Paul, MN, September, 1999.
[6] Osa, R.H., *Mercury Atmospheric Processes: A Synthesis Report, workshop proceedings from the Expert Panel on Mercury Atmospheric Processes*, Tampa, FL, March 16-18, 1994.

bio-amplified as it works its way up the food chain. Methyl mercury, in particular, is a potent neurotoxin[3].

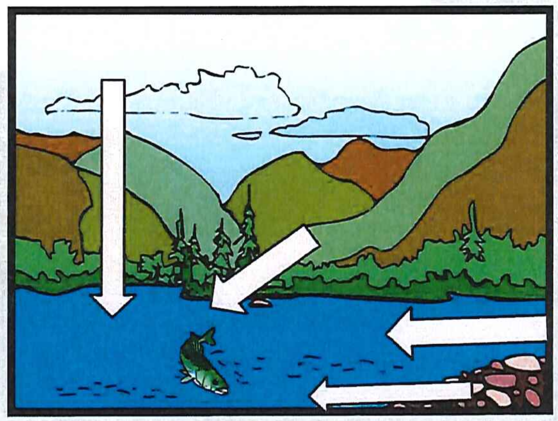
Based on the Abbott and Susong study, southeastern Idaho is short of ecosystems conducive to mercury methylation, such as wetlands. Instead, they found that a large fraction (over 80%) of deposited Hg(II) from INEEL emissions appears to have been reduced to the elemental form and re-emitted to join the atmospheric reservoir of elemental mercury. Given its similar terrestrial environment, we would expect that a large fraction of any oxidized mercury emitted by the P4 operations and deposited in the vicinity of the facility would undergo similar reduction and re-emission as elemental mercury.

4.0 CONCLUSION

Based on our knowledge of the chemical speciation of the P4 facility's mercury emissions, and the results of Abbott and Susong's research, we expect that at least 1085 pounds per year of the plant's mercury emissions enter the global elemental mercury reservoir through either direct emission or via deposition, followed by reduction and re-emission. The remaining 15 pounds per year are likely distributed about the local terrestrial and aquatic environment.

The above preliminary conclusions use our knowledge of the quantity and speciation of P4-Soda Spring's mercury emissions and extrapolate the findings of INEEL's research. Based on Dr. Lindberg's critique of the 2008 ICF modeling, it should be disregarded since it relied on obsolete and inaccurate emission source data, and did not adequately account for specific aspects of the regional environment that significantly affect mercury cycling. Significant uncertainty derives from local difference in the potential for reduction and re-emission of oxidized mercury. A more definitive analysis would require considerably more input data and the use of a mercury impact fate and transport model properly reflecting the region's environment.

Pathways of Mercury (Hg) in Idaho Waterways



Steve Lindberg

Emeritus Fellow, Oak Ridge National Laboratory, US Department of Energy
Adjunct Professor, University of Michigan, University of Tennessee, and University of Nevada (emeritus)

Presentation to Board of Environmental Quality, Idaho Department of Environmental Quality

Boise, ID, Feb. 12, 2009

Beyond the Bio

EIGHTH INTERNATIONAL

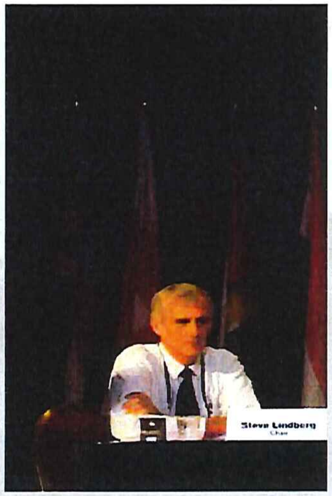
CONFERENCE ON
MERCURY
AS A GLOBAL
POLLUTANT

MADISON WISCONSIN
AUGUST 6–11, 2006

MERCURY AS A GLOBAL POLLUTANT

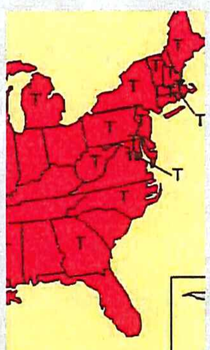
Germany

Japan



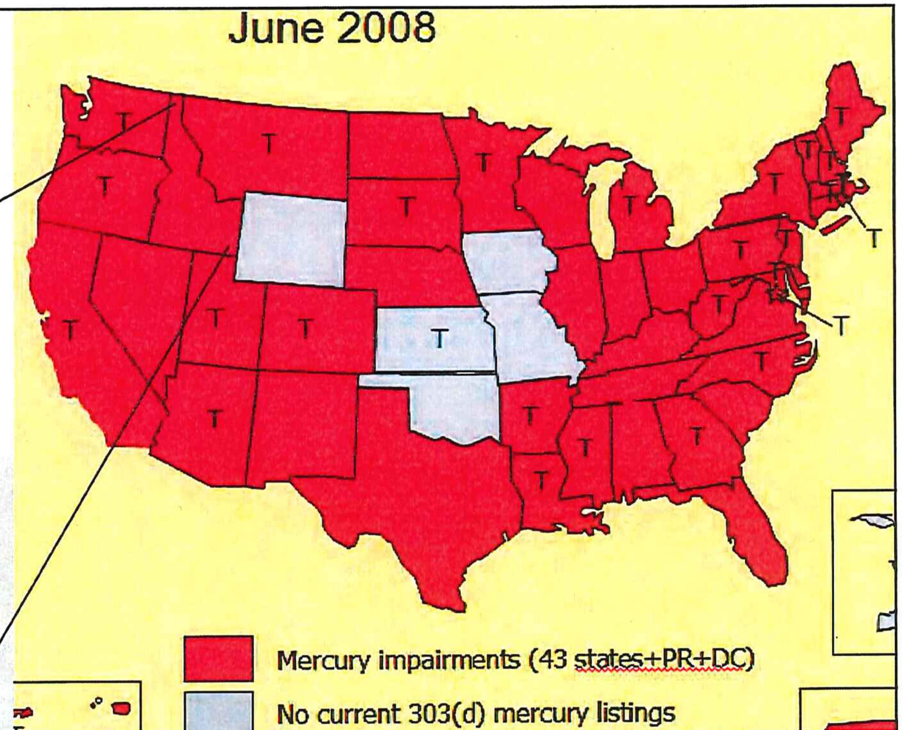
"Declaration: Need for effective national and international policies to address mercury issues"

Vermont Atty Gen'l and CFLs



Work with FL, MI, NY, TN, & VA DEQ's on Hg issues

The Issue:
Fish advisories issued for mercury in Idaho



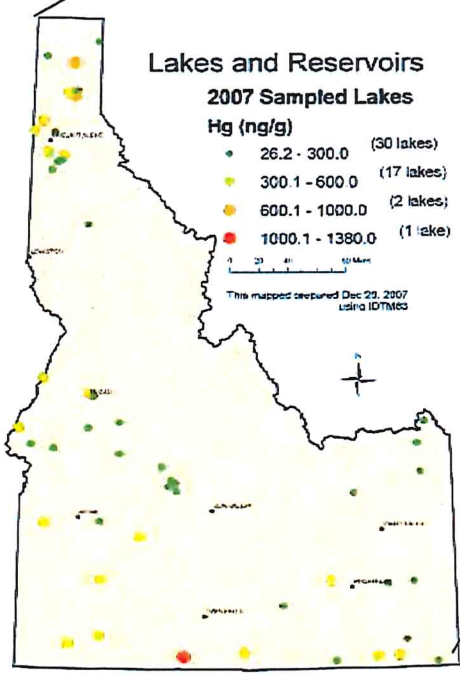


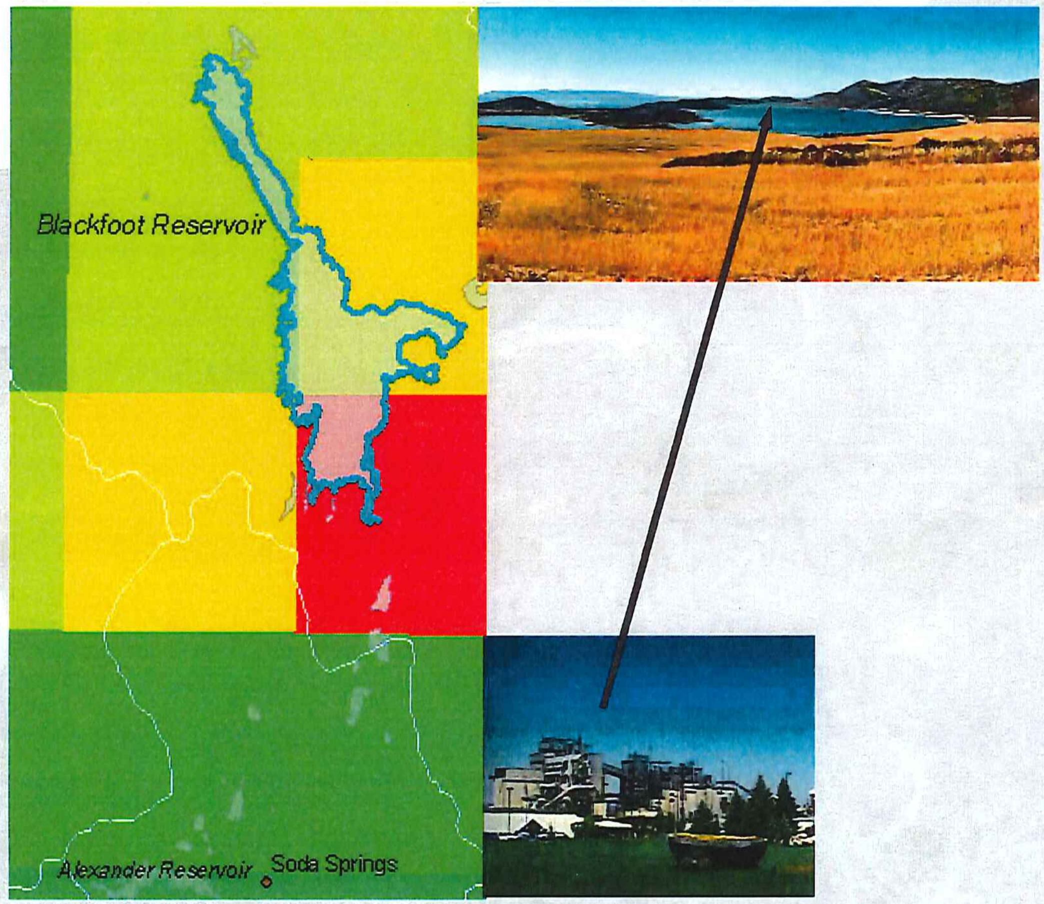
Figure 4. Mercury in Fish Tissue Results by Lake

The Resolution:
Where is it coming from, and what can be done about it?

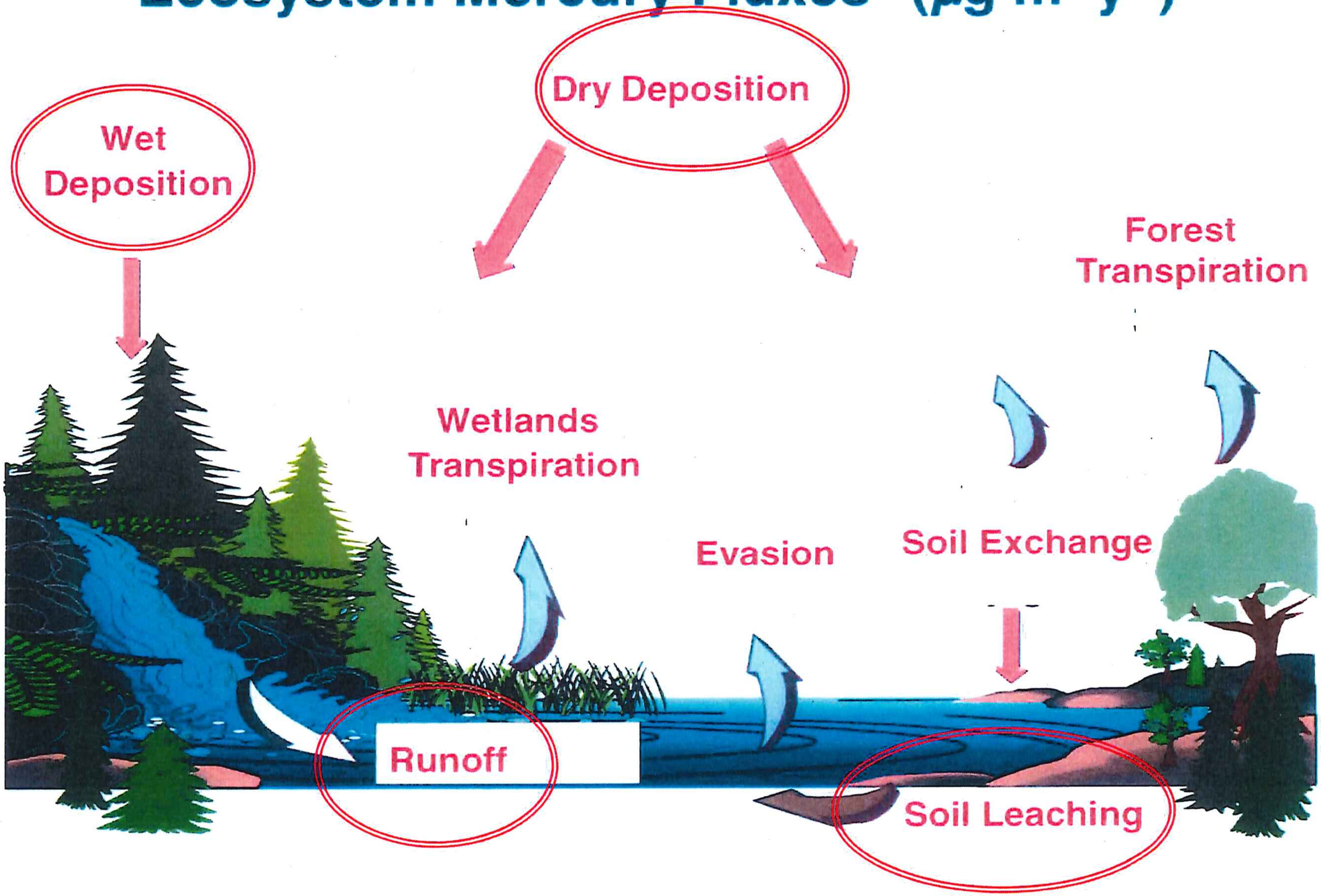
Major Points of Discussion

- Complex cycle with numerous pathways
- West is unique (in the air and on the ground)
- Idaho industrial emissions are comparatively small
- Modeling useful, but has its limitations
- REMSAD significantly over-predicts hot-spots & the impact of P4
- Methyl mercury influenced by much more than just mercury
- Geologic Hg deposits are ubiquitous in the west
- The atmosphere is not the only route of Hg entry to waters
- Inflow and sediment transport exceeds atmospheric deposition of Hg to some western waterways
- Additional regulation of Idaho industrial atmospheric sources may not achieve any measurable reduction in fish Hg

Mercury does impact Idaho waters, but is the current focus properly directed?



Ecosystem Mercury Fluxes* ($\mu g\ m^{-2} y^{-1}$)



*(Lee and Iverfeldt 1991, Lindberg 1996, Rea et al. 1996, Scherbatskoy et al. 1998)

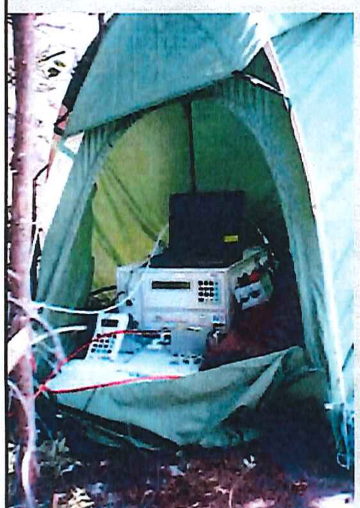
ornl

Three Basic Forms of Hg

Hg(0) ↑↓ — Elemental (Hg^o, vol., long lived)
~95-99% (in air)

Hg(II) ↑↓ — Ionic (RGM, HgII, vol., soluble)
~1-5% (as RGM & Hg_p)

MeHg — Methylated (most toxic form)
<<1%





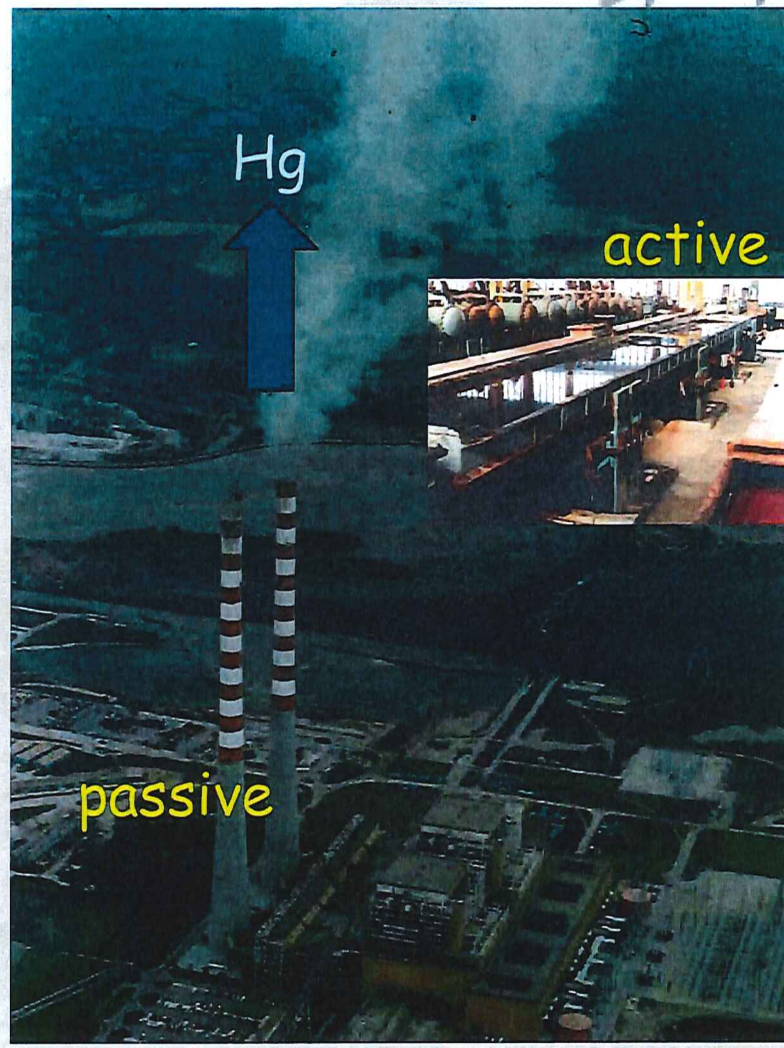
Two Primary Sources of Atmospheric Mercury

Roughly 2000-3000
T/y each globally

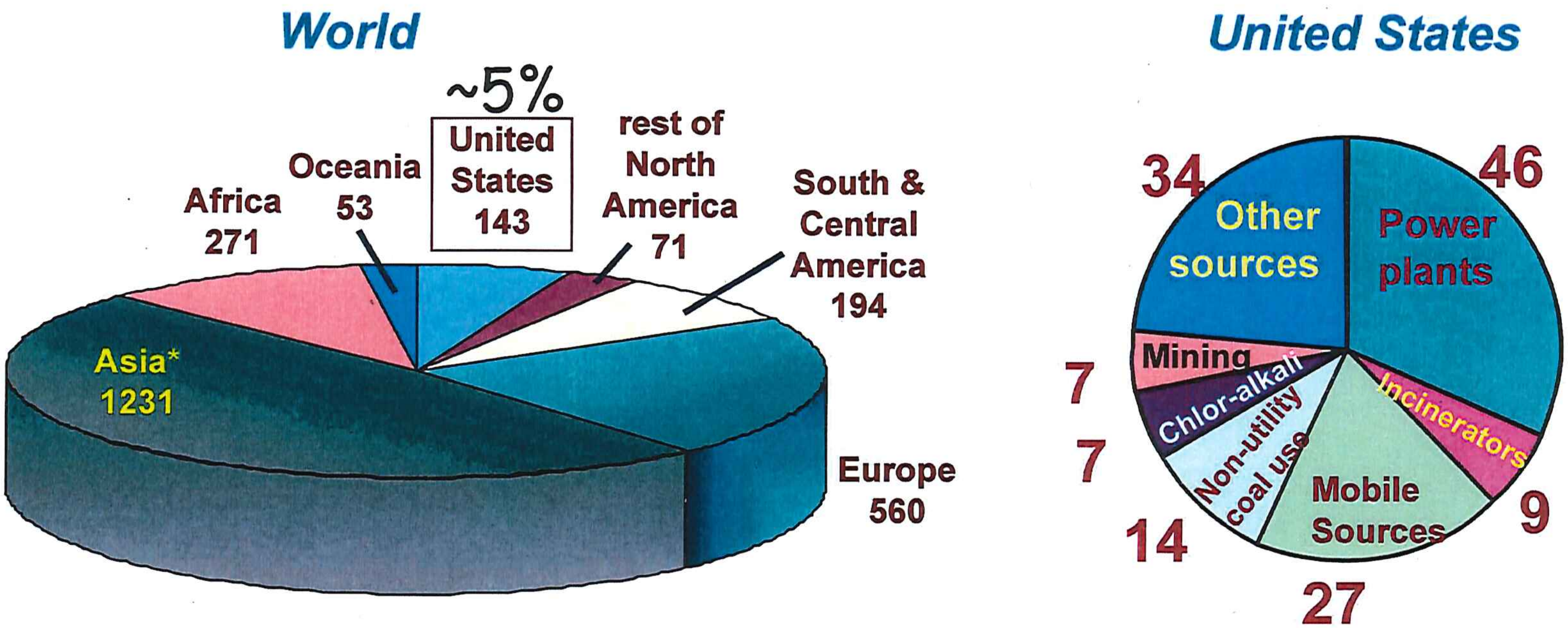
Anthropogenic

Hg

"Natural"



Mercury air emissions due to human activity (tons/yr)

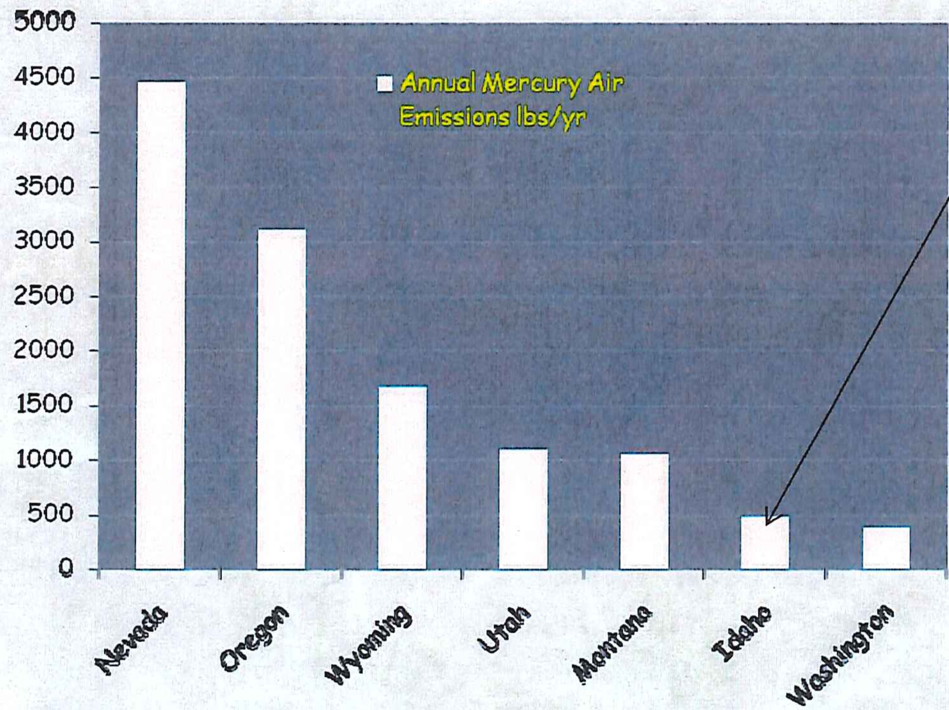


Global total, human emissions ~2500 tons per year

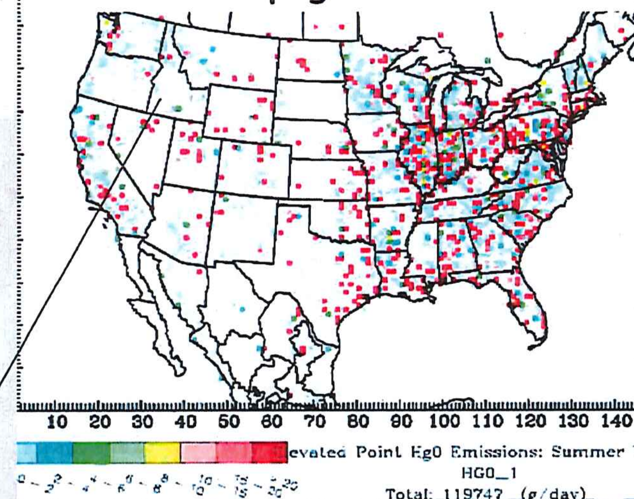
U.S. total, human emissions ~140 tons per year

Putting Idaho industry into regional perspective: The west is unique

Annual Mercury Air Emissions for Idaho and Adjacent States*

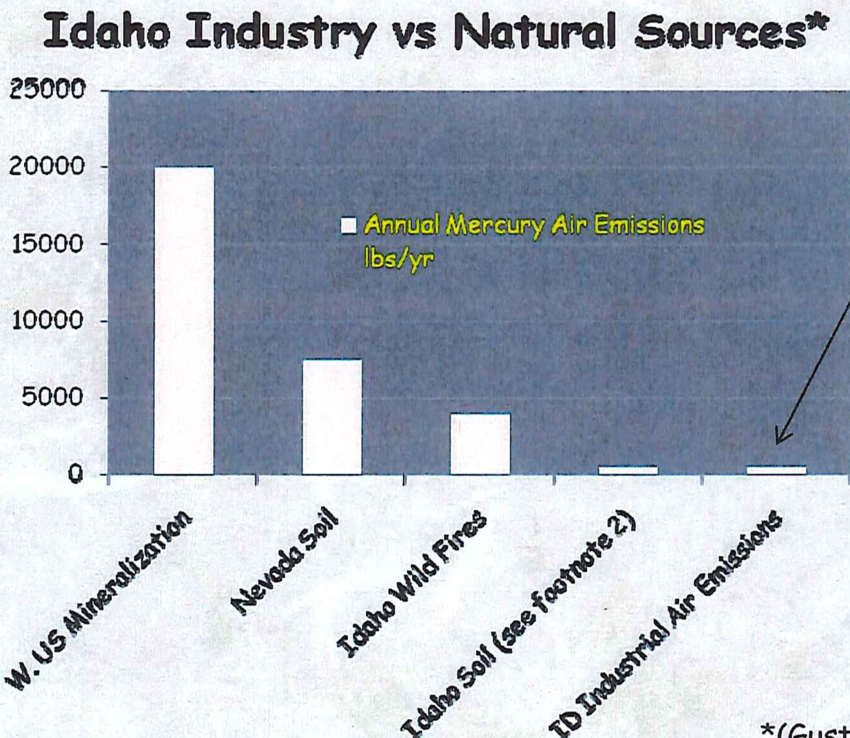


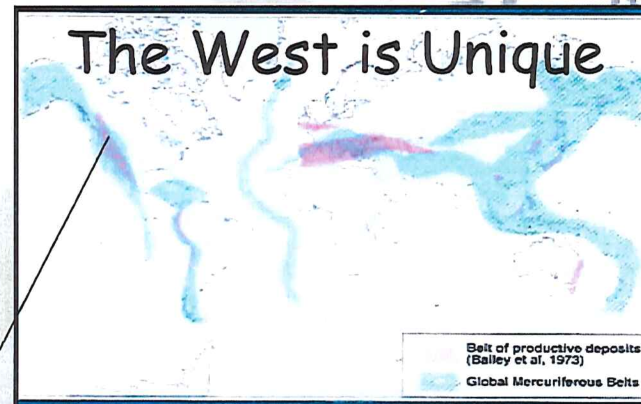
US Anthropogenic Emissions



*(USEPA TRI 2006)

Comparing Idaho Industry with Regional Natural Air Emissions

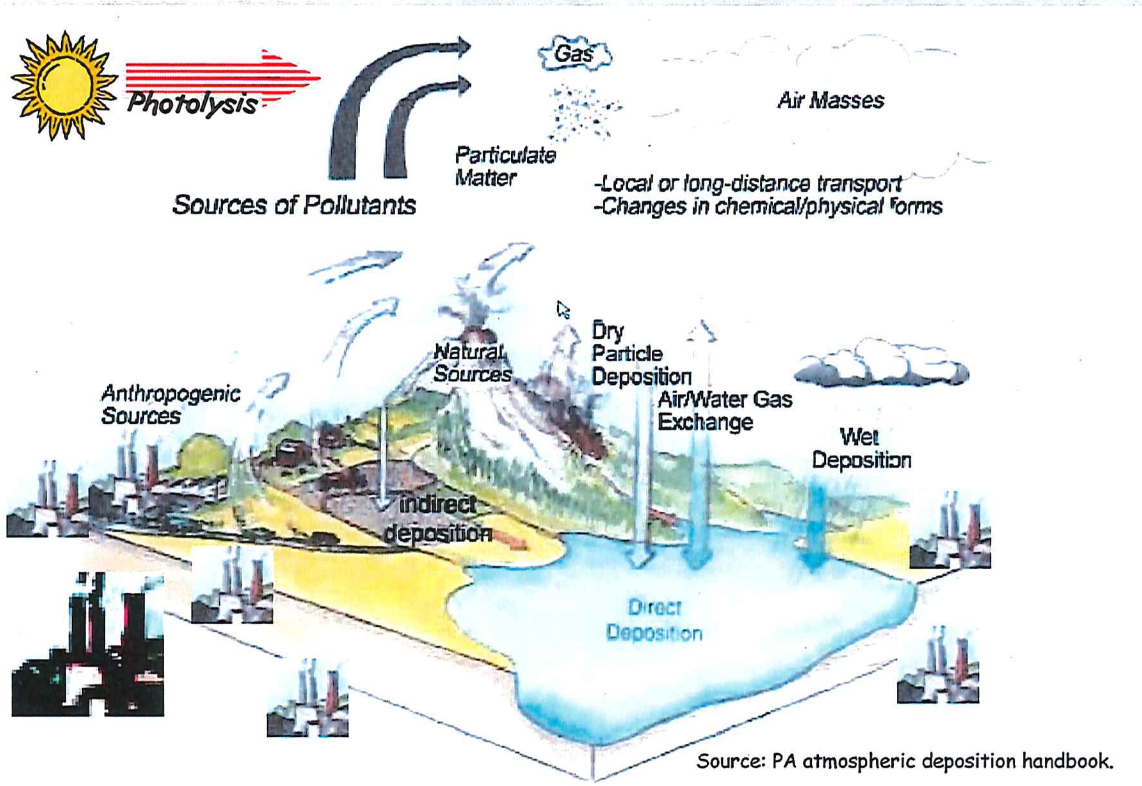




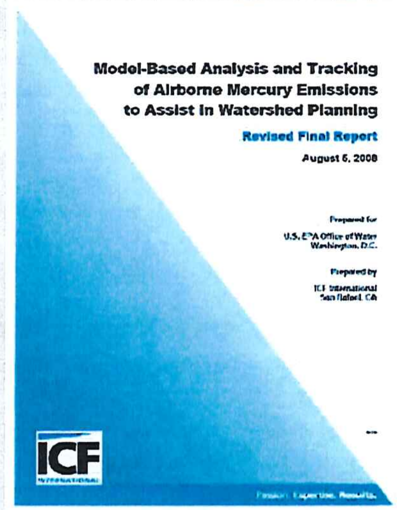
*(Gustin et al 2008, Lindberg 2008, Wiedinmyer and Freidli 2007),

Approaches to Source Attribution

- Stable mercury isotopes ($^{202}Hg/^{200}Hg$)
- Airborne tracers of convenience (Ni/V)
- Models



Source: PA atmospheric deposition handbook.



Model-Based Analysis and Tracking of Airborne Mercury Emissions to Assist in Watershed Planning

Revised Final Report

August 6, 2008

Prepared for

U.S. EPA Office of Water
Washington, D.C.

Prepared by

ICF International

ICF

REMSAD has been applied to Idaho

The Role of Modeling in Source Attribution

EIGHTH INTERNATIONAL

CONFERENCE ON
MERCURY
AS A GLOBAL
POLLUTANT

MADISON WISCONSIN
AUGUST 6–11, 2006

*(Lindberg et al 2007)

"Modeling uncertainty must be relayed to and understood by policy makers*"

- Uncertainty ←→ Assumptions and Estimates (A&E's)**
- Model simulations of natural systems always based on various A&E's
- Understanding of atmospheric mercury is immature, meaning these A&E's have a strong bearing on model results
- Modelers adjust A&E's to obtain agreement with measurements (e.g., wet deposition), but does not assure accuracy everywhere
- Lack of adequate deposition data and measurement methods severely limits ability to validate Hg source/receptor models
- Deposition models applied to complex terrain exhibit important additional levels of uncertainty***

*(Expert Panel 2007) **(Bullock, 2006) *** (Hicks et al 1985)

EPA acknowledges uncertainty issues with REMSAD Model

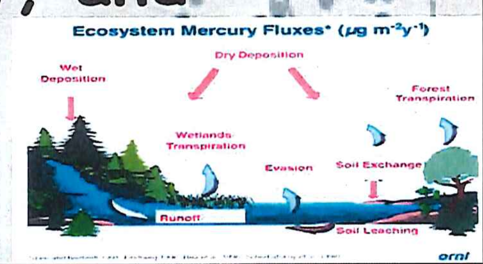
REMSAD recognized to overestimate measured deposition, and to vary from other regional Hg models

•Atkinson (2008): "...measures of performance indicate ... REMSAD ... overestimate wet deposition of mercury"

•Bullock et al (2008): "...concentrations of some mercury species simulated by the different models compared...vary by more than a factor of 10"

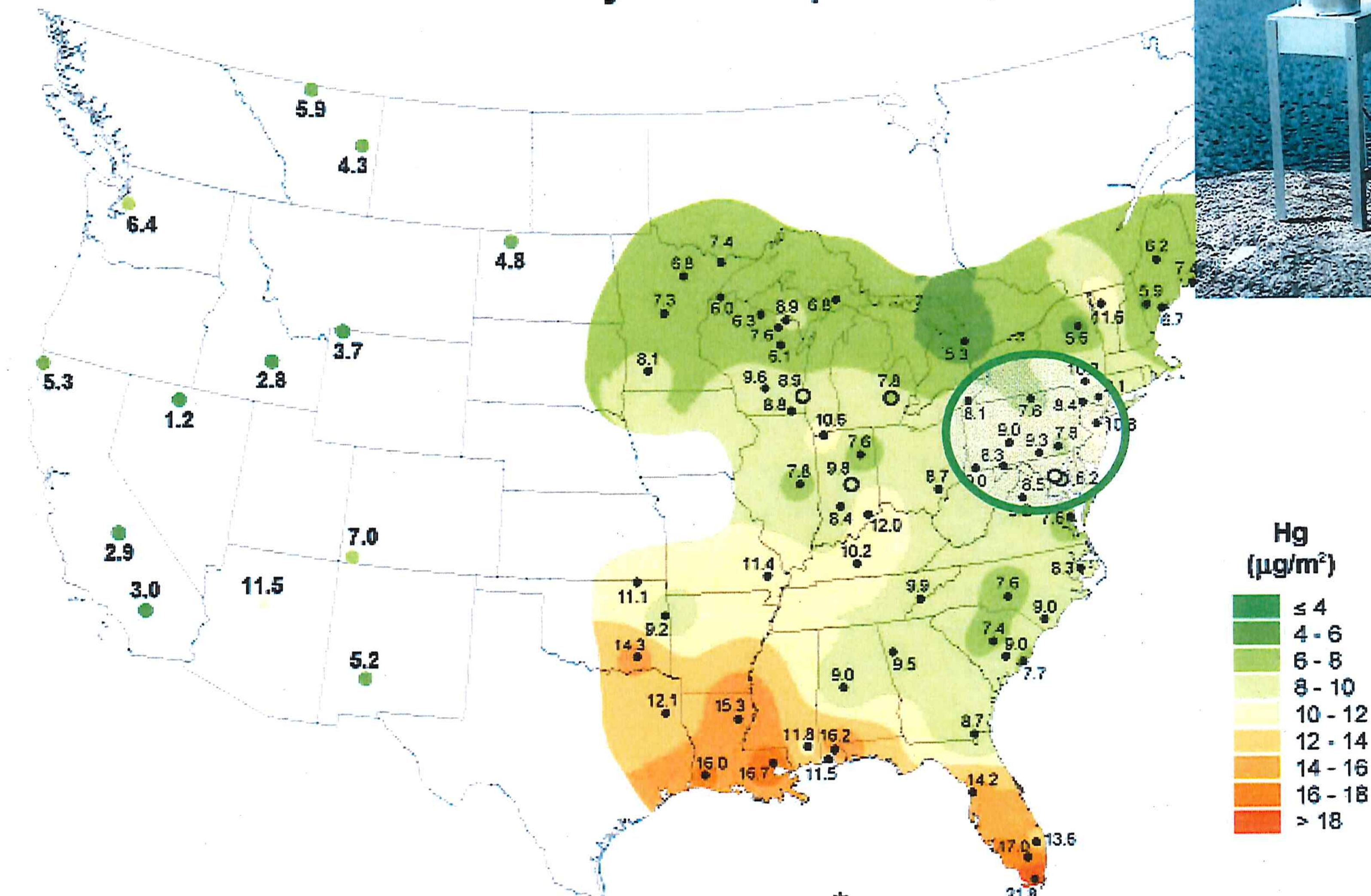
It follows that predicted hotspots of deposition by REMSAD are both uncertain and potentially biased

"Model validation absolutely necessary, and requires local measurements*"



*(Expert Panel 2007)

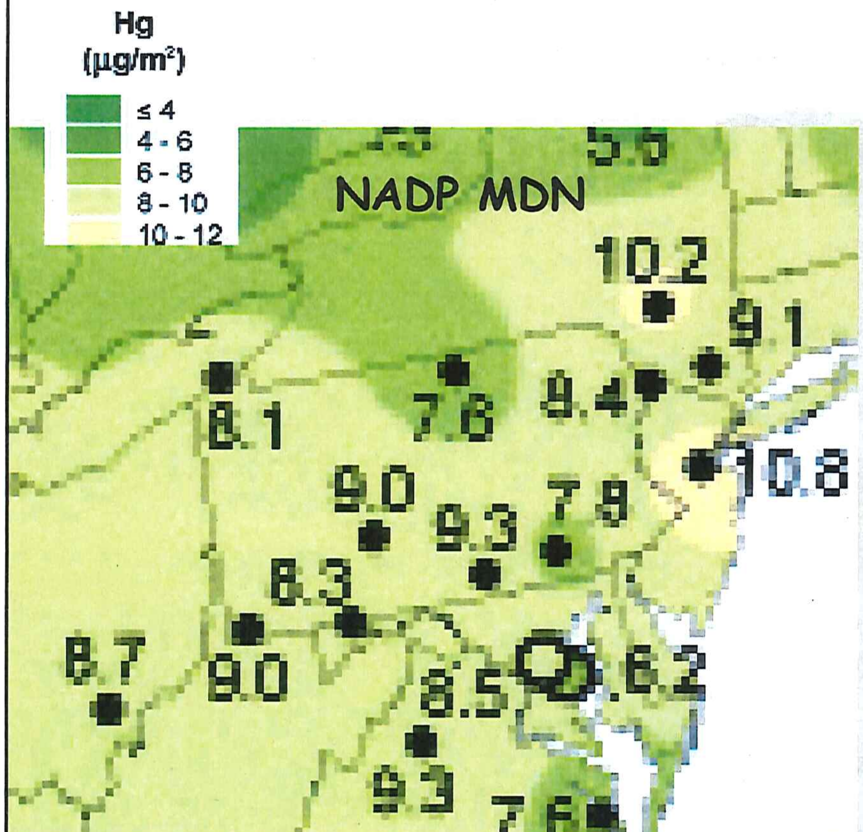
Total Mercury Wet Deposition, 2007

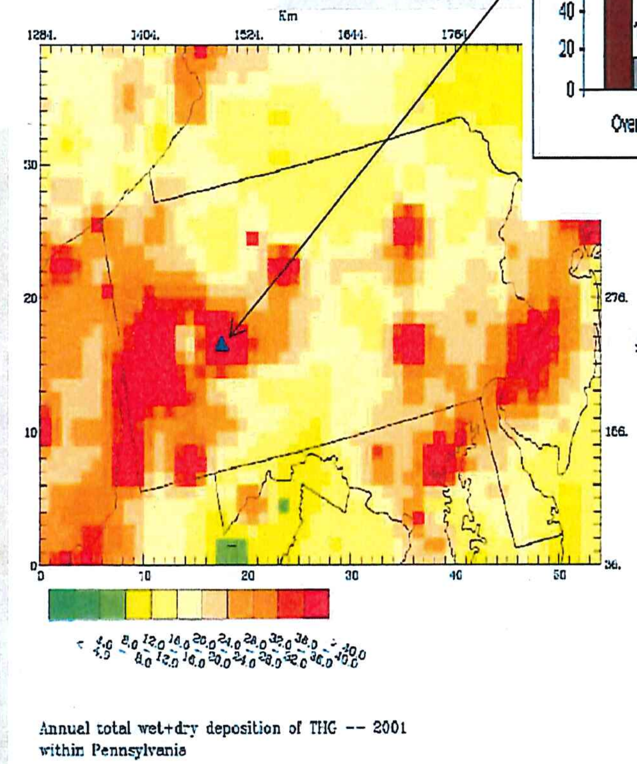


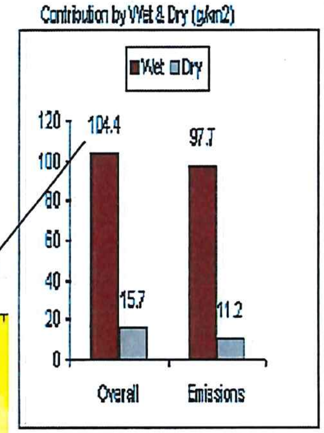
National Atmospheric Deposition Program/Mercury Deposition Network*

*(Lindberg and Vermette 1995; Vermette et al 1995; Illinois State Water Survey 2007)

Comparison of REMSAD* model wet deposition with the most dense MDN state network (PA)

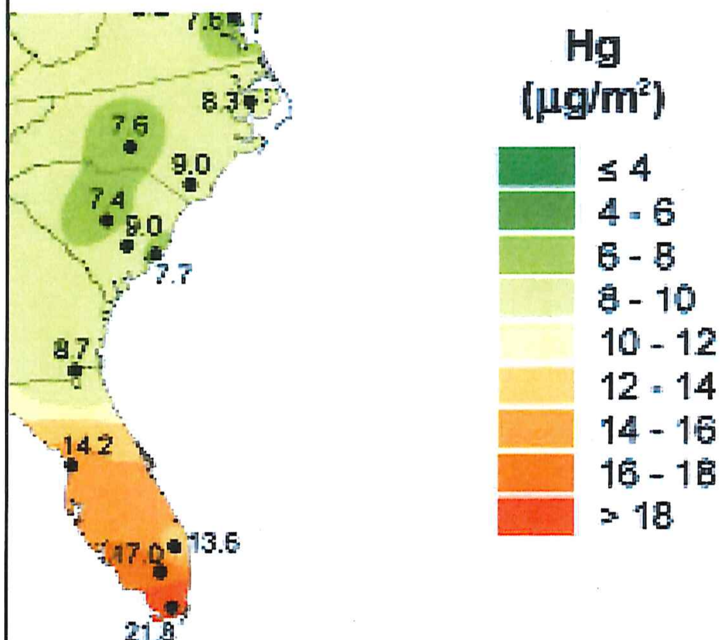




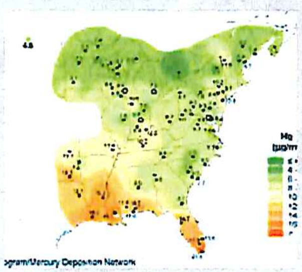


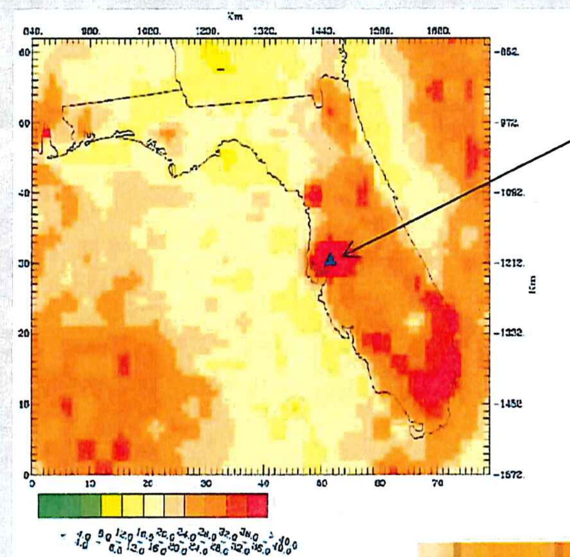
*(Model-Based Analysis and Tracking of Airborne Mercury Emissions to Assist in Watershed Planning. U.S. EPA Office of Water, Final Report, November 30, 2006, Atkinson 2008)

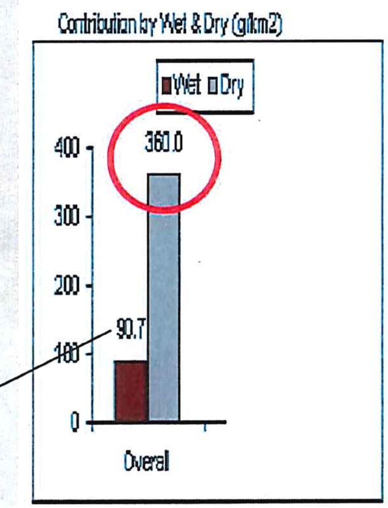
Many other examples exist, such as the case in Florida*



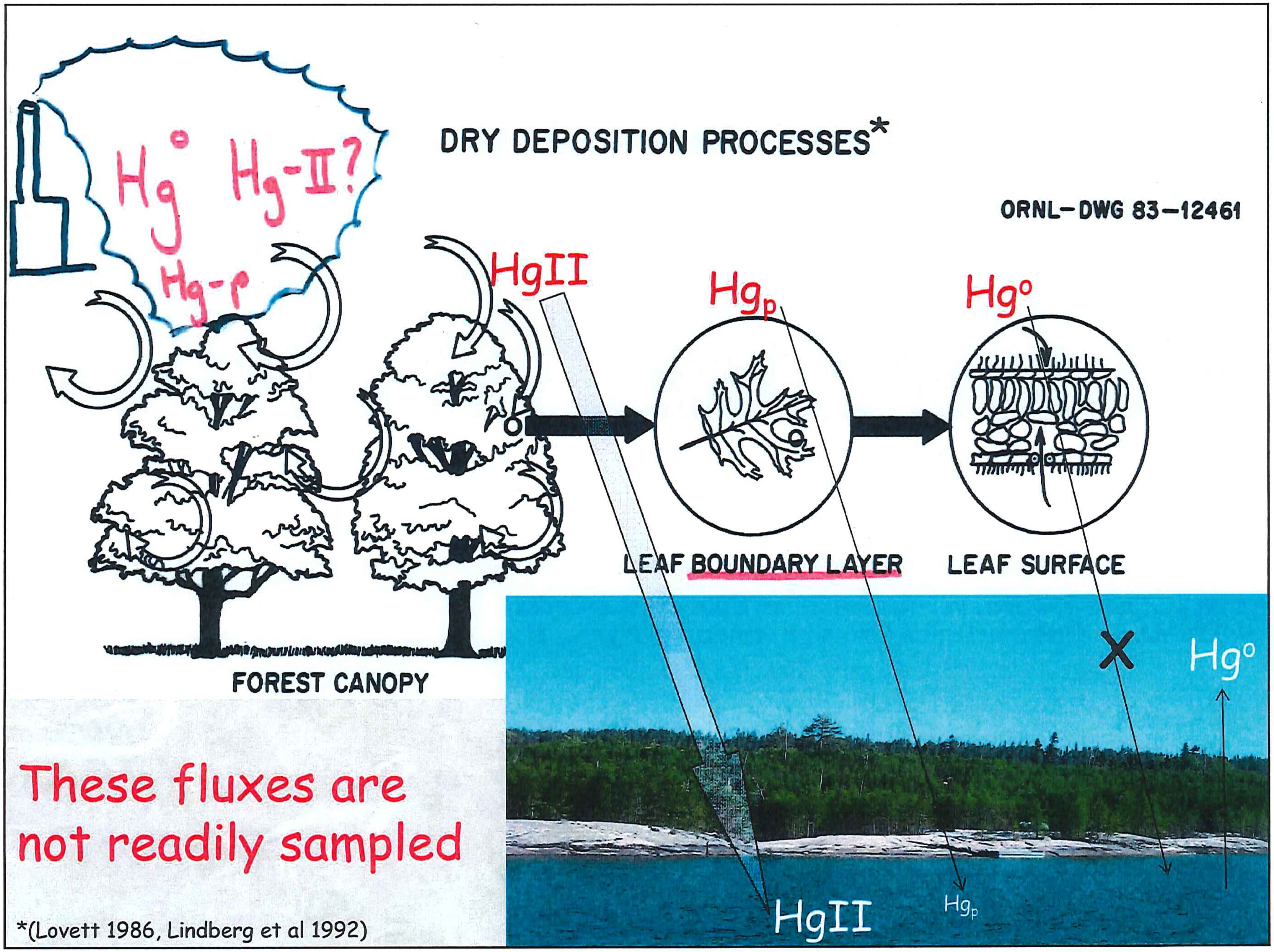
NADP MDN







*(Atkinson 2008)

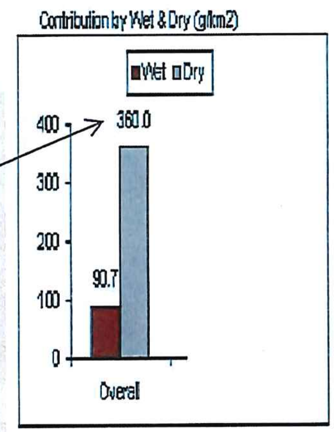

DRY DEPOSITION PROCESSES*
ORNL-DWG 83-12461
Hg° Hg-II?
Hg-p
HgII
Hgp
Hgo
LEAF BOUNDARY LAYER
LEAF SURFACE
FOREST CANOPY
Hgo
HgII
Hgp
These fluxes are not readily sampled
*(Lovett 1986, Lindberg et al 1992)

Comparison to dry deposition not straightforward, but some short-term measurements recently published for Florida's Everglades:

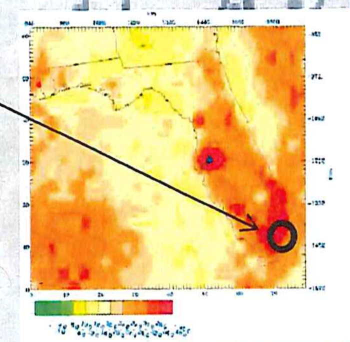
Surrogate Surfaces* ~5-15 ng/m2/d (water)

Model (Hotspot) ~1000 ng/m2/d**

Model (Everglades) >100 ng/m2/d



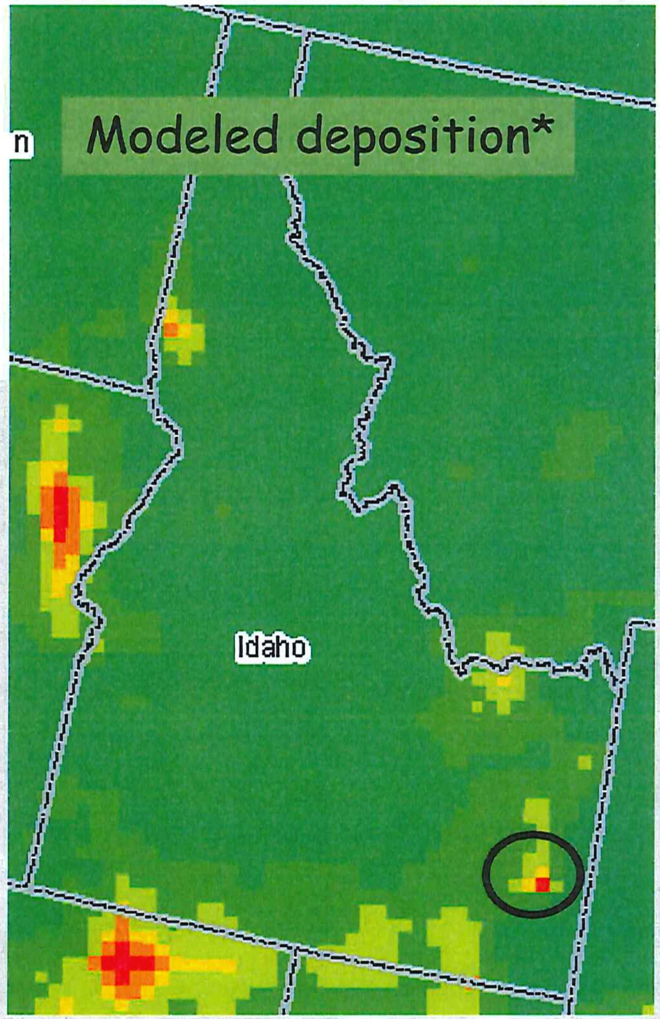
(REMSAD Florida)

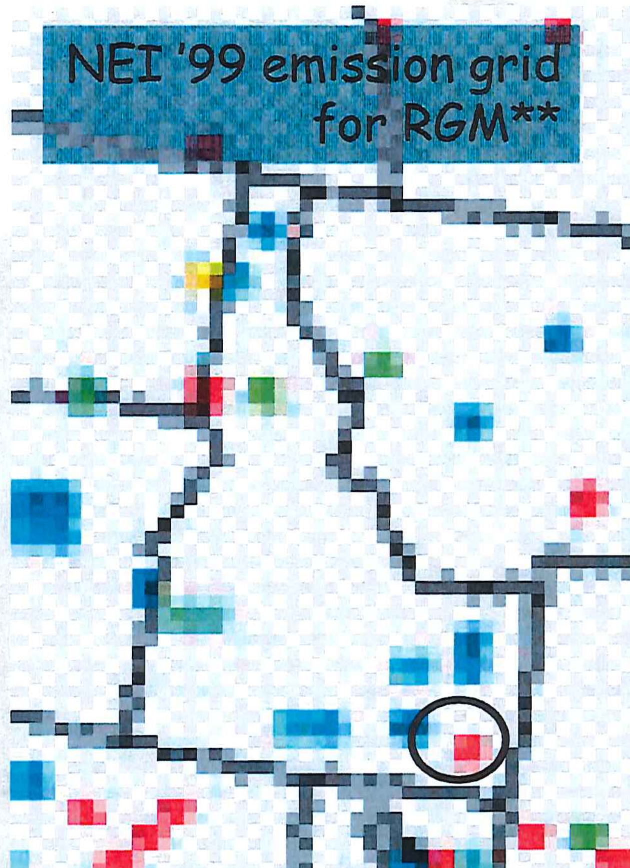


*(Marsik et al 2007, Lindberg et al 2005)

** (scaled from REMSAD, Atkinson 2008)

REMSAD Model Results in Idaho

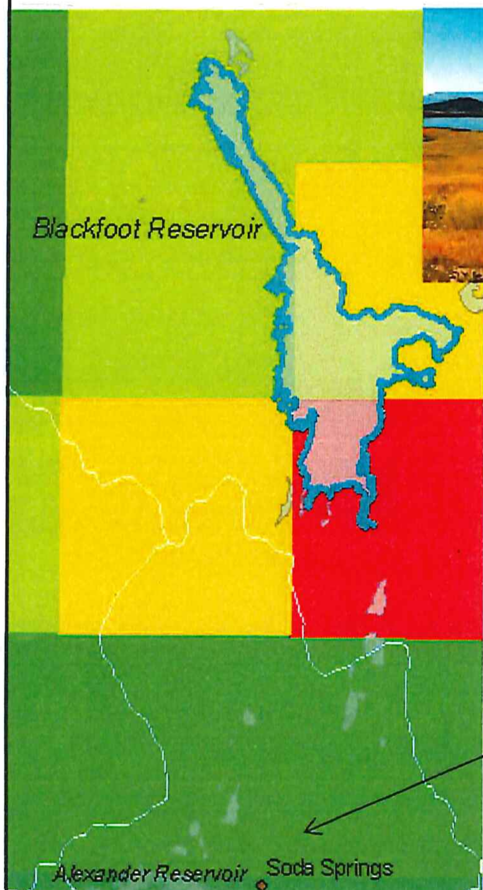


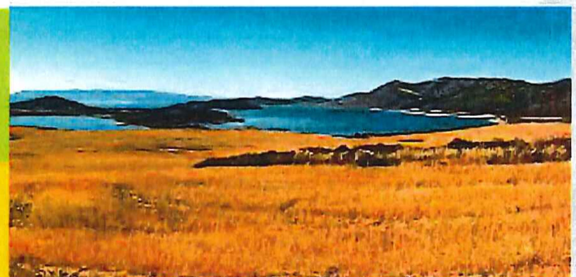


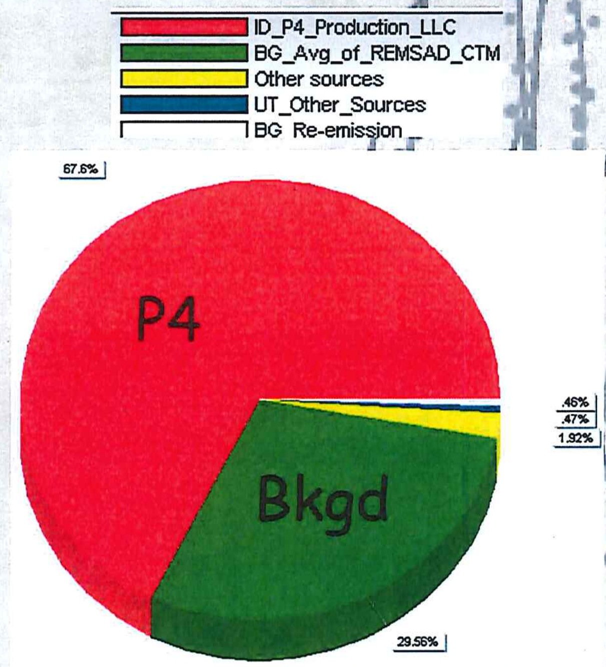
*(Atkinson,2008)
**(Lin et al 2004)

2008 REMSAD Model Results for Blackfoot Reservoir

REMSAD model predicts P4 to contribute ~65% of the Hg deposited to Blackfoot Reservoir*



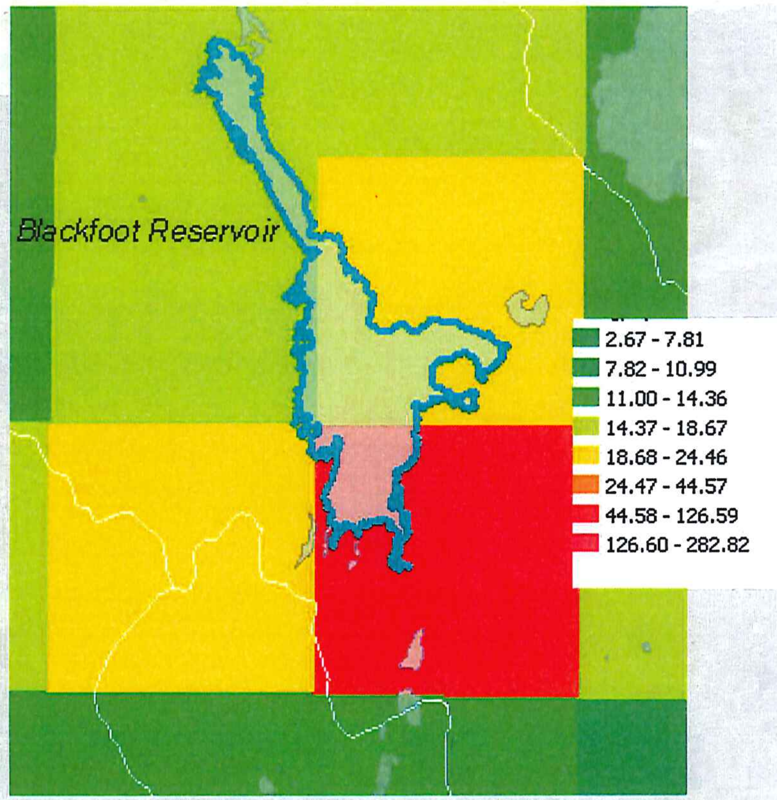




*(Atkinson,2008)

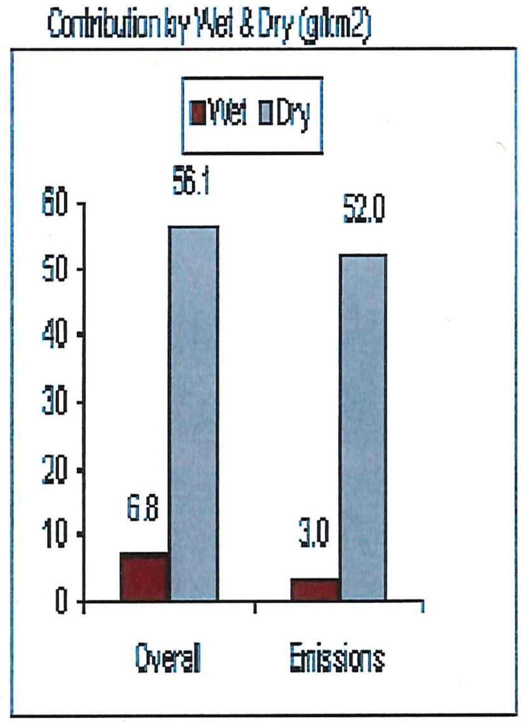
REMSAD Model Results for Blackfoot Reservoir

Model predicts a hotspot deposition ~60 ug/m2/y**



**(Mean deposition to reservoir ~30 ug/m2/y, to watershed ~15; Atkinson 2006, 2008)

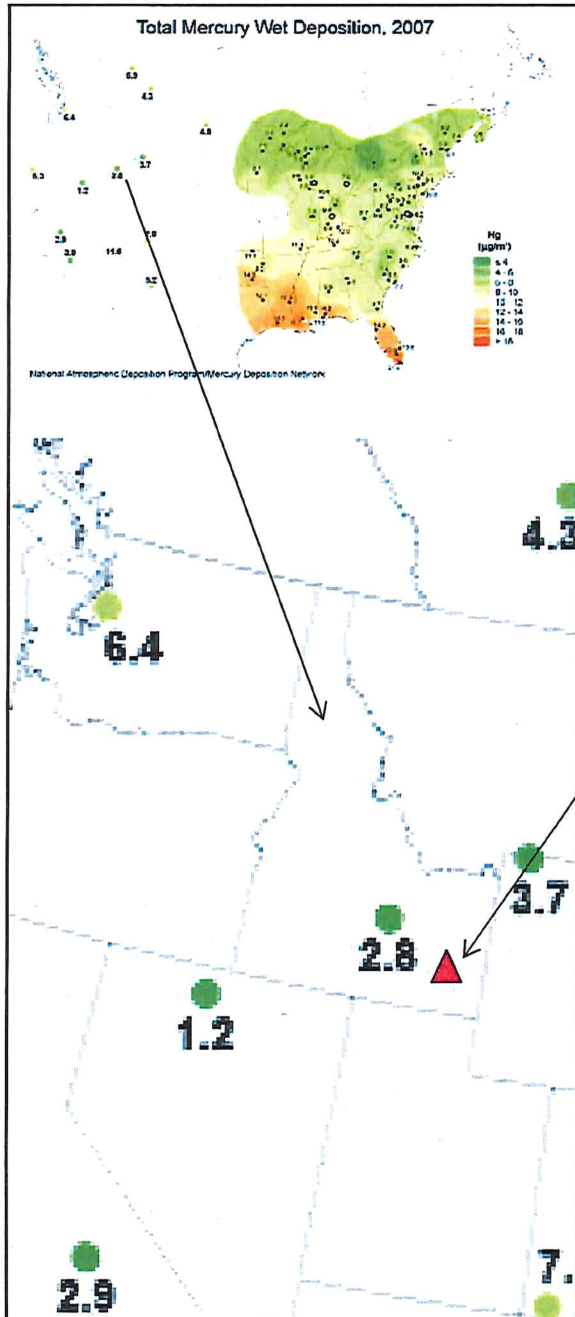
Figure 7-47b. Summary of Mercury Tagging Results for 2001 for Idaho with Average Background, at the Location of the Maximum Simulated Annual Hg Deposition from Sources within the State, Grid: I = 131, J = 209 (Total = 63.0 g/km2). *

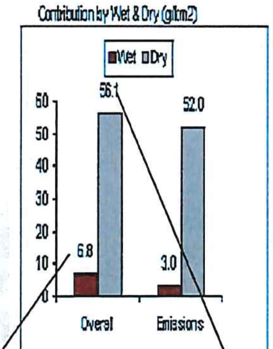


***(Model-Based Analysis and Tracking of Airborne Mercury Emissions to Assist in Watershed Planning**

REMSAD PPTM Results: Mercury Deposition Contribution Analysis, Atkinson 2006)

REMSAD model results for Blackfoot Reservoir compared to measurements





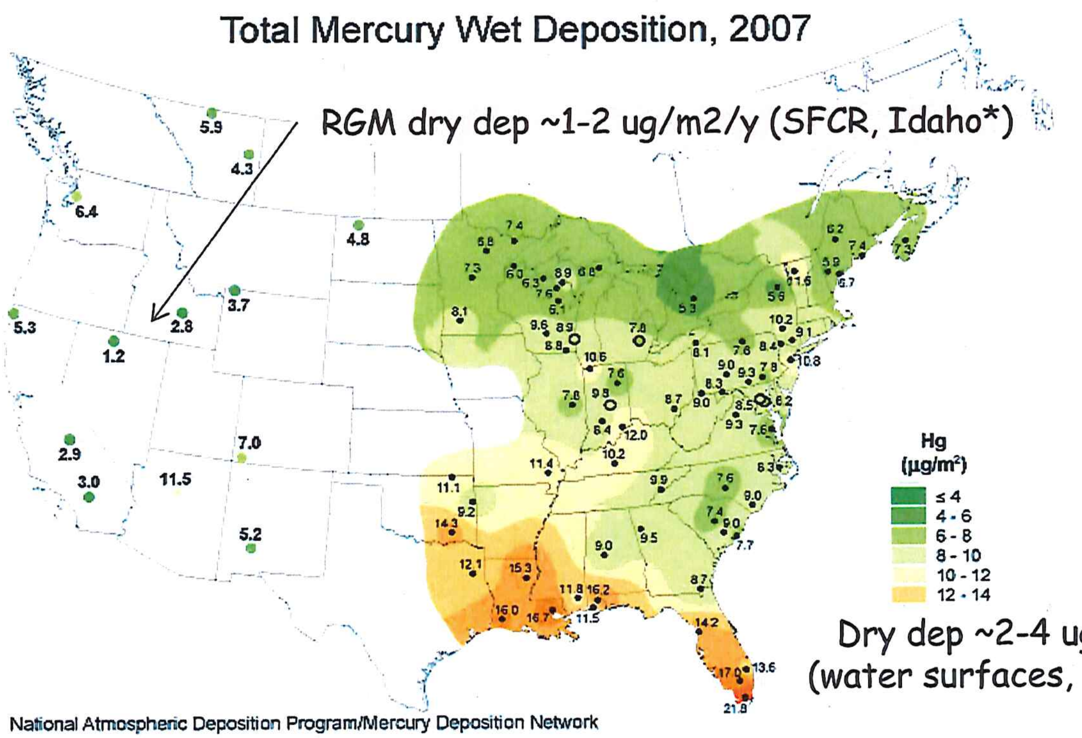
Measured dry deposition to water surfaces: ~2-4 ug/m2/y*

*(Marsik et al 2006,)

REMSAD model results for other Idaho sites compared to measurements

REMSAD modeled deposition (ug/m2/y)

13	SFCR
22	Owyhee
15	Bruneau
14	Willow
13	Portneuf
29	Soda Springs



RGM dry dep ~1-2 ug/m2/y (SFCR, Idaho*)

Dry dep ~2-4 ug/m2/y (water surfaces, Florida)

(*Abbott et al 2008, **Marsik et al 2006)

REMSAD used outdated emission data for P4

Data used in 2008 REMSAD runs for P4

Facility	Mercury Emissions (t/yr) Elemental	Divalent gas**	Particle bound	TOTAL	% of Total ID Hg Emissions	
P4 Production LLC	0.367	0.046	0.046	0.459	55	

**Speciation of mercury emissions is very important in REMSAD (Atkinson, 10/09/2008)

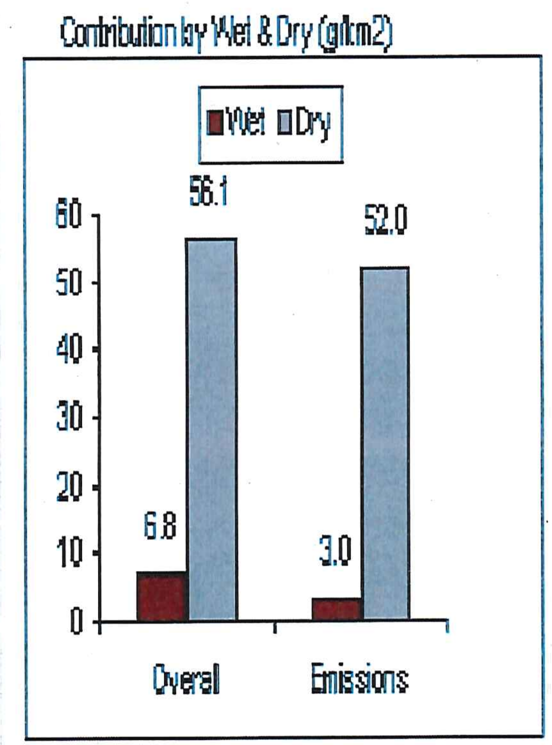
New Stack Measurements for P4*

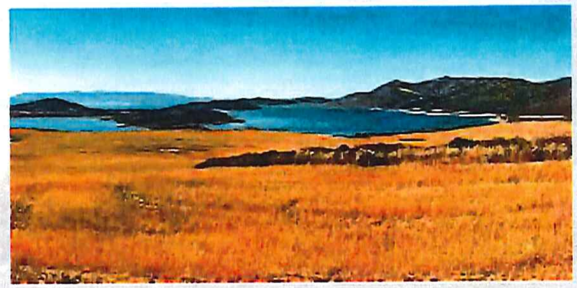
Facility	Elemental	Divalent gas**	Particle bound	TOTAL	% of Total ID Hg Emissions	
P4 Production LLC	0.20	0.003	0.013	0.22		

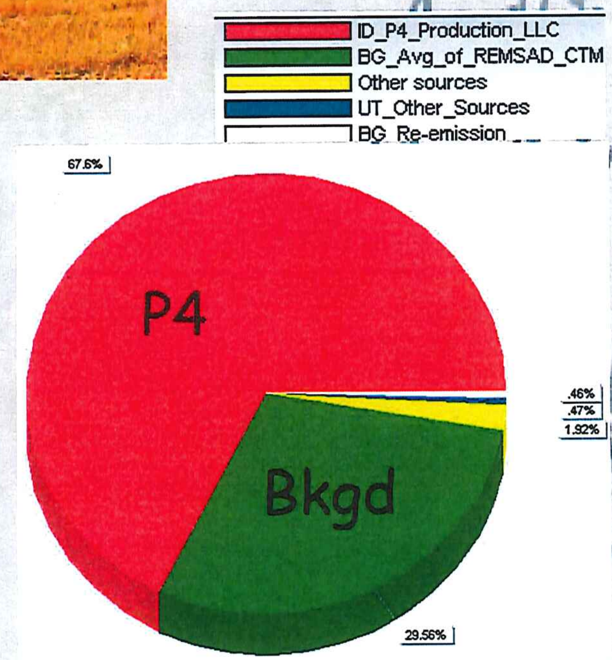
Fraction of modeled emissions	54%	6.5% **	28%	48%		

*(Stack gas emission data from EPA/Ontario Hydro method, 2006)

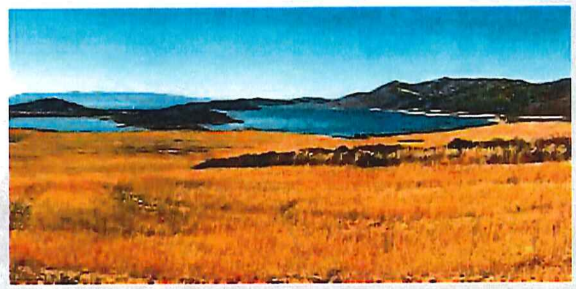
2008 REMSAD Model Results for Blackfoot Reservoir: Implications of modeling outdated P4 Emissions Data

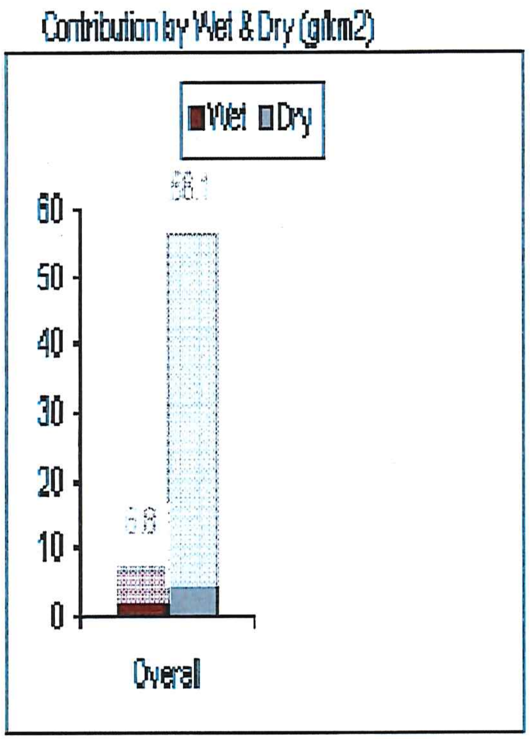


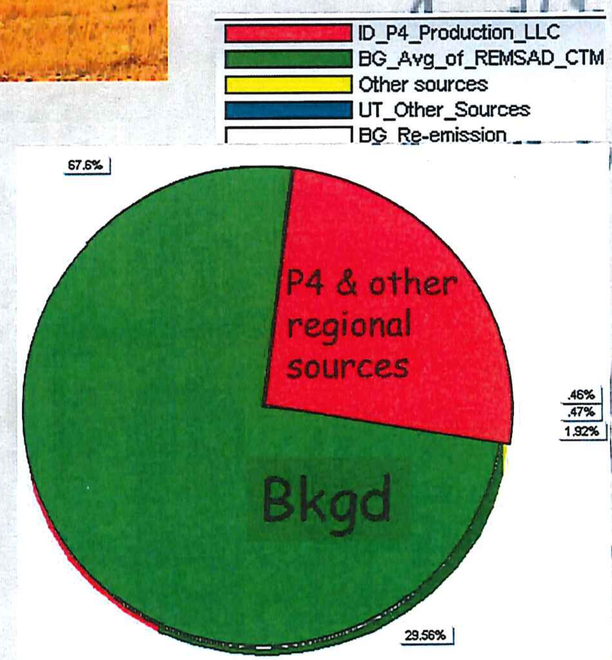




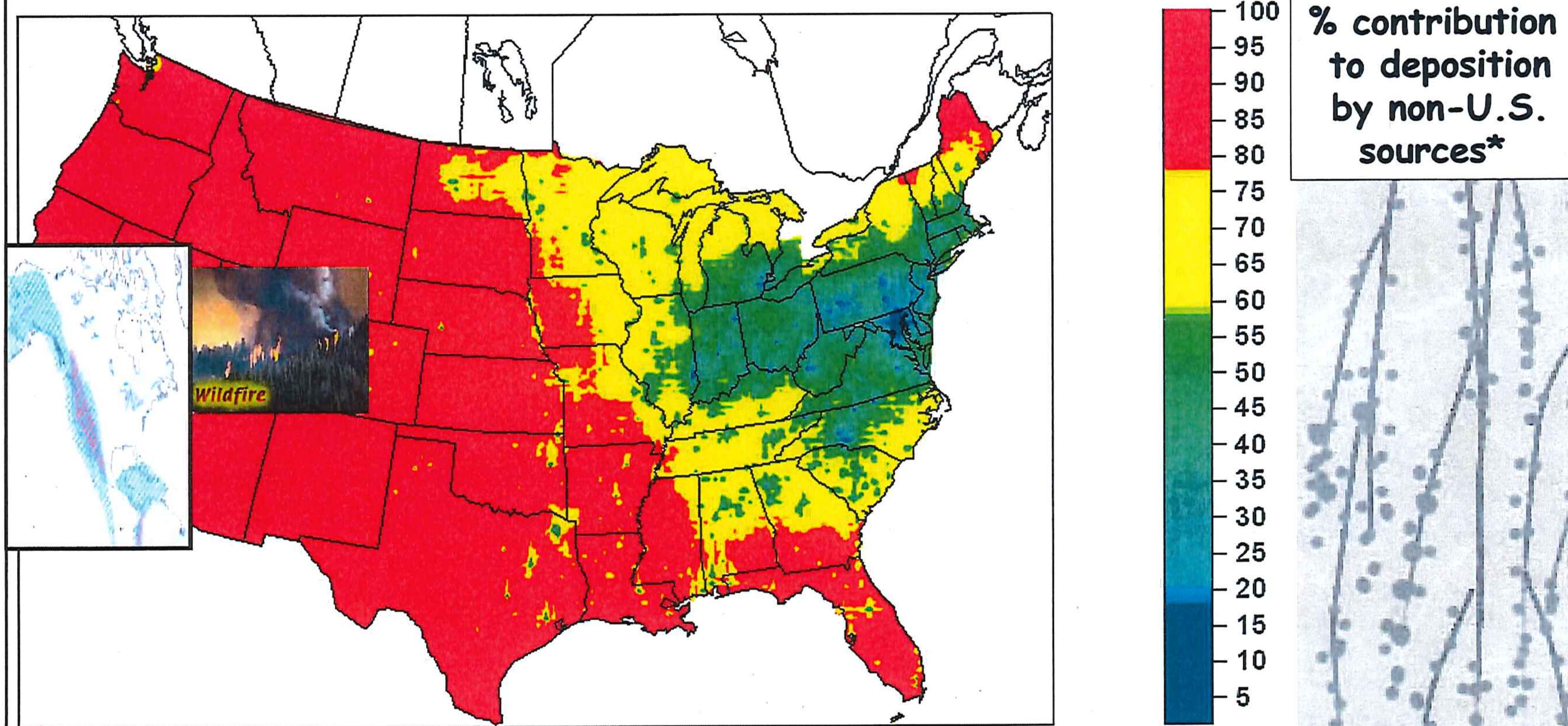
2008 REMSAD Model Results for Blackfoot Reservoir: Implications of modeling outdated P4 Emissions Data





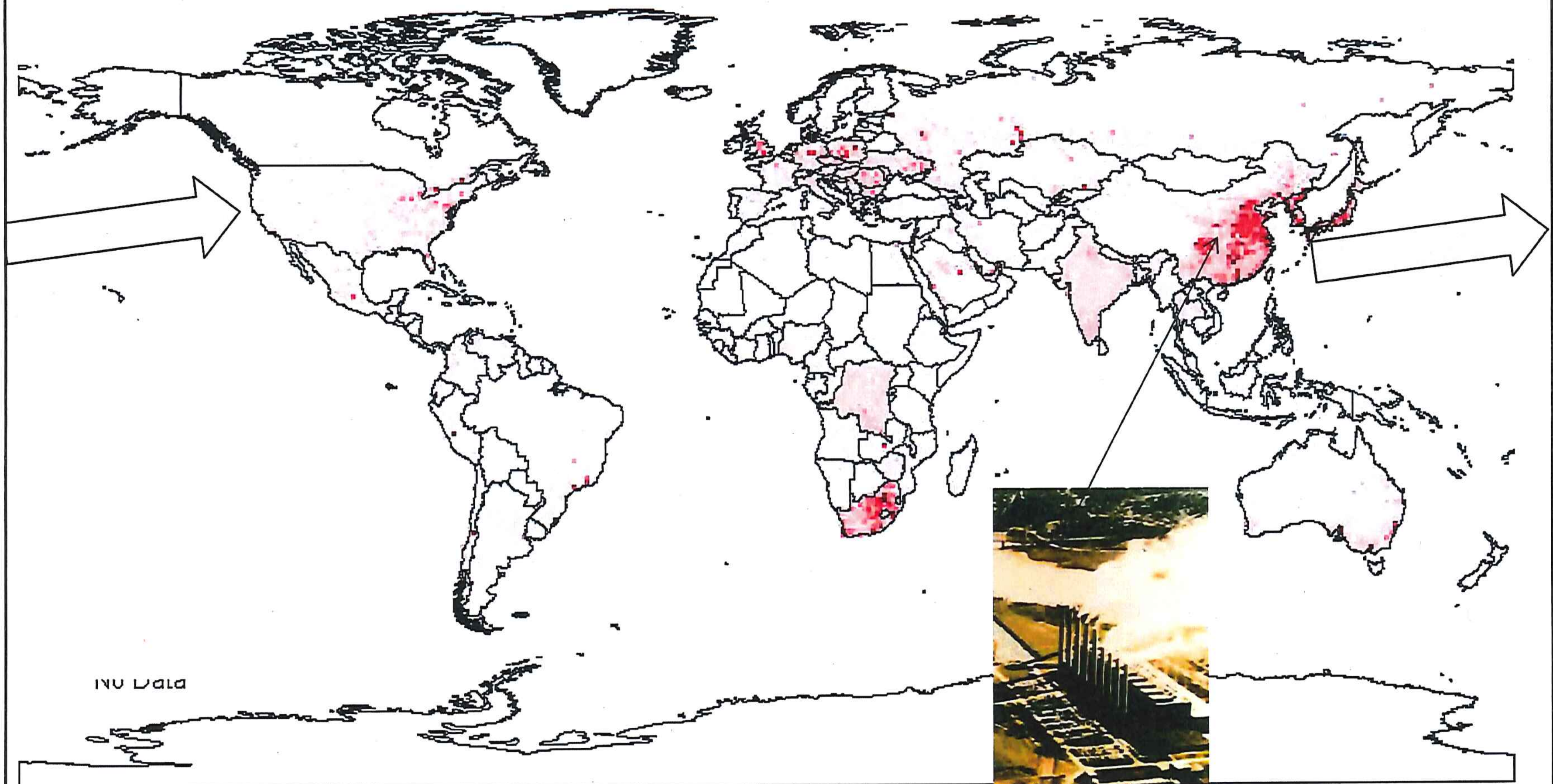


How Much Atmospheric Mercury Originates Outside the U.S.?

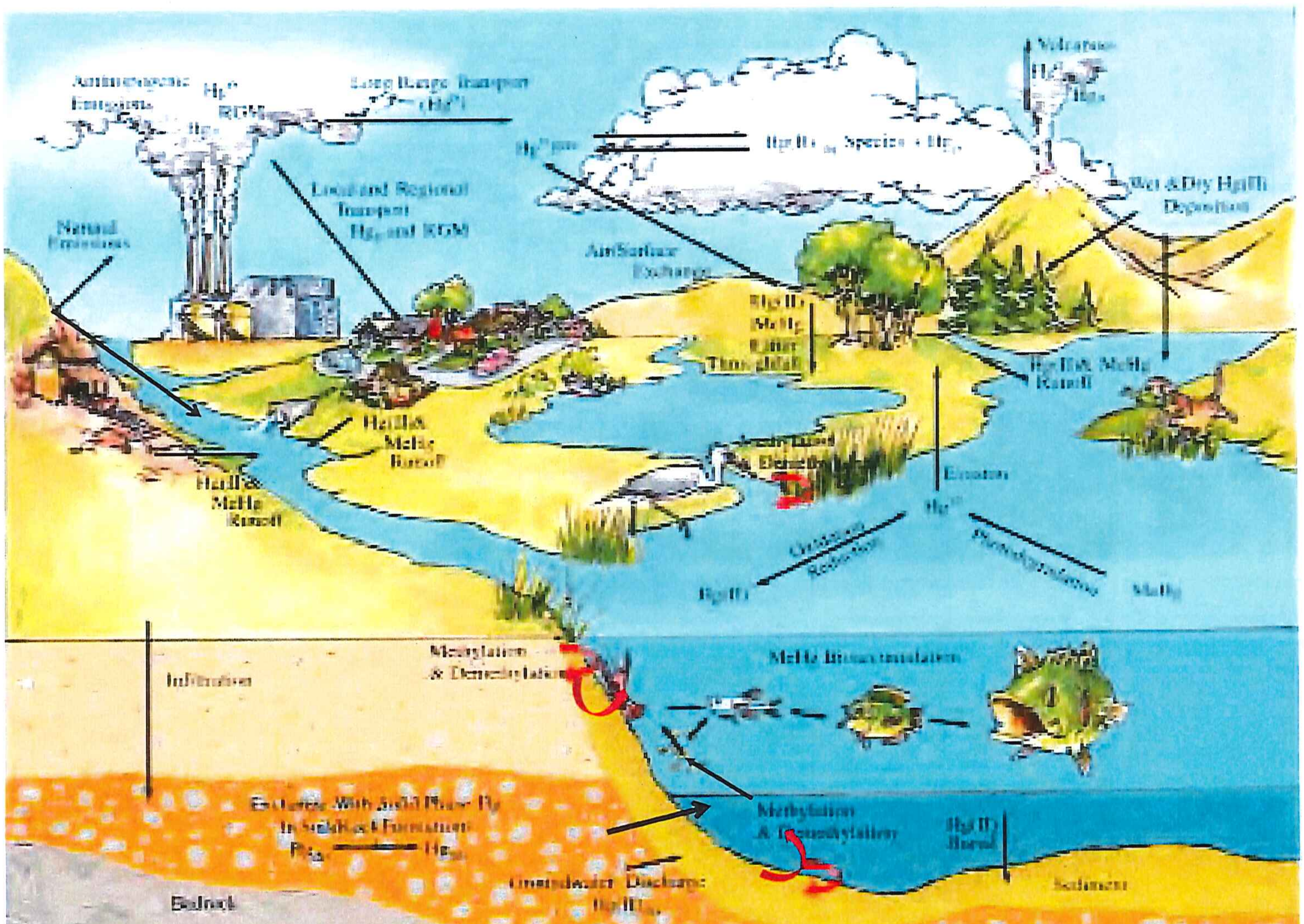


*(Seigneur et al. 2004, EPA 2005, EPRI 2007)

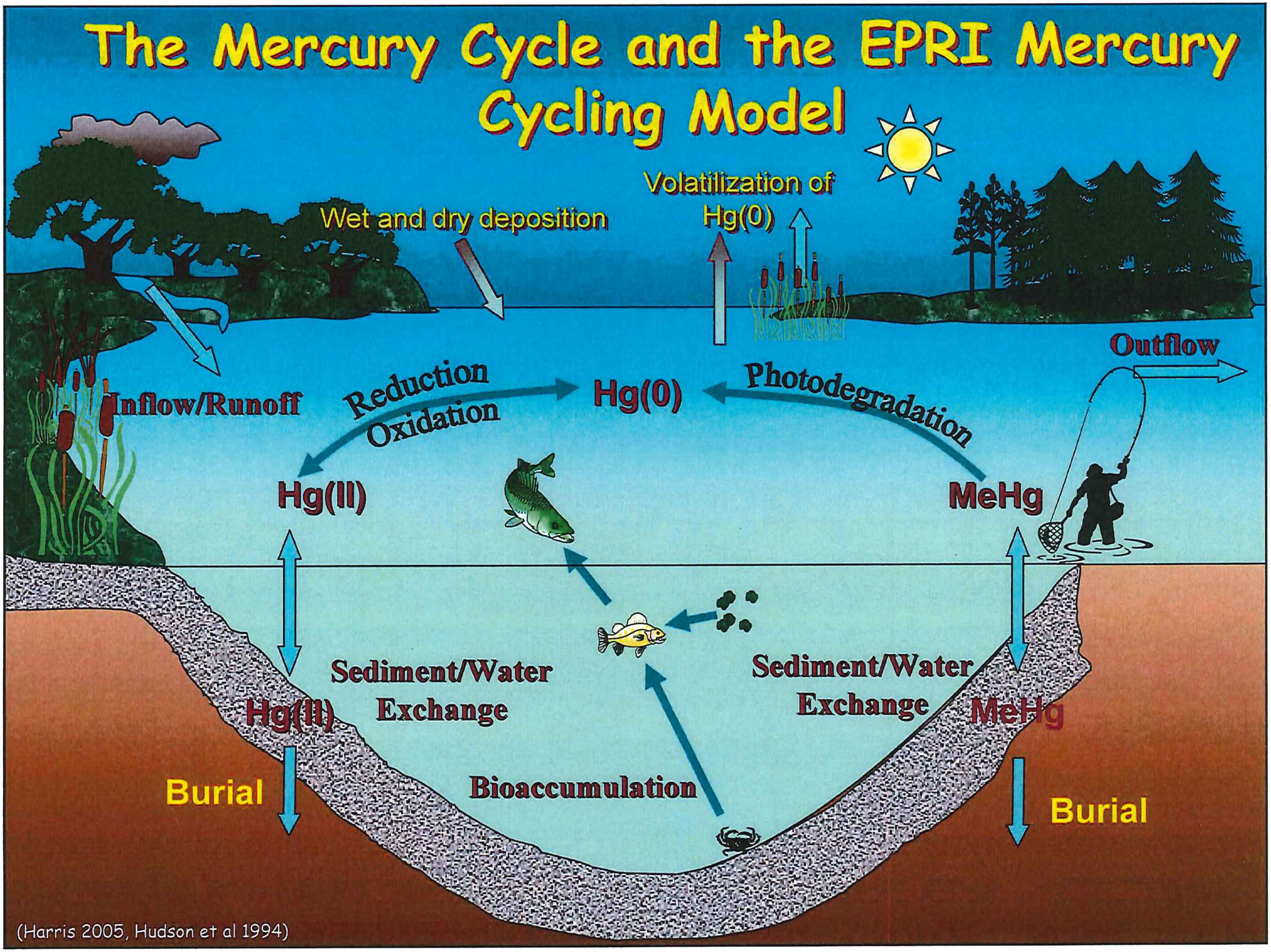
Anthropogenic Emissions to Air are Global
(recent inventory ~2500 T/y)



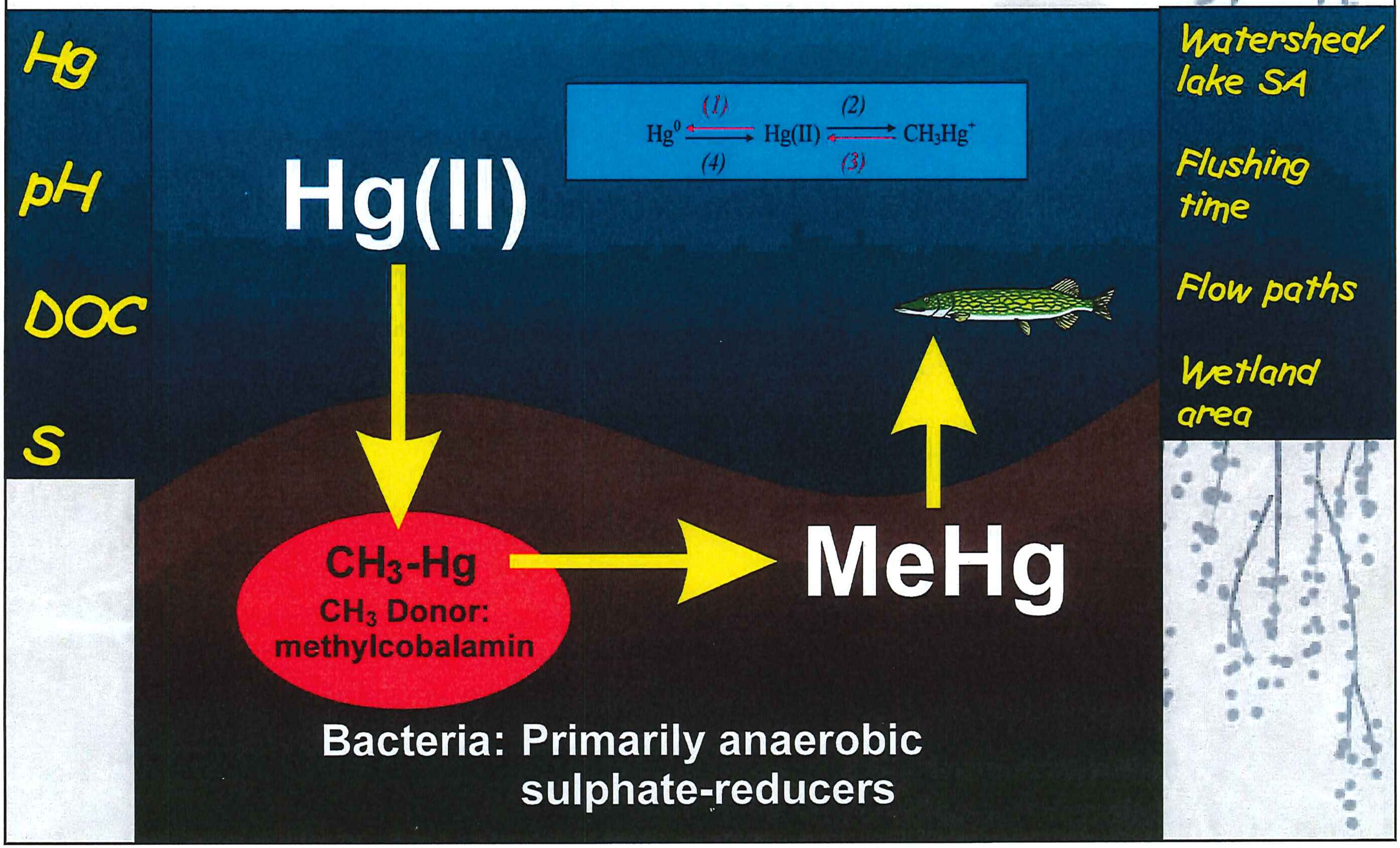
Mercury Cycling is Complex
(in both Air and Water)



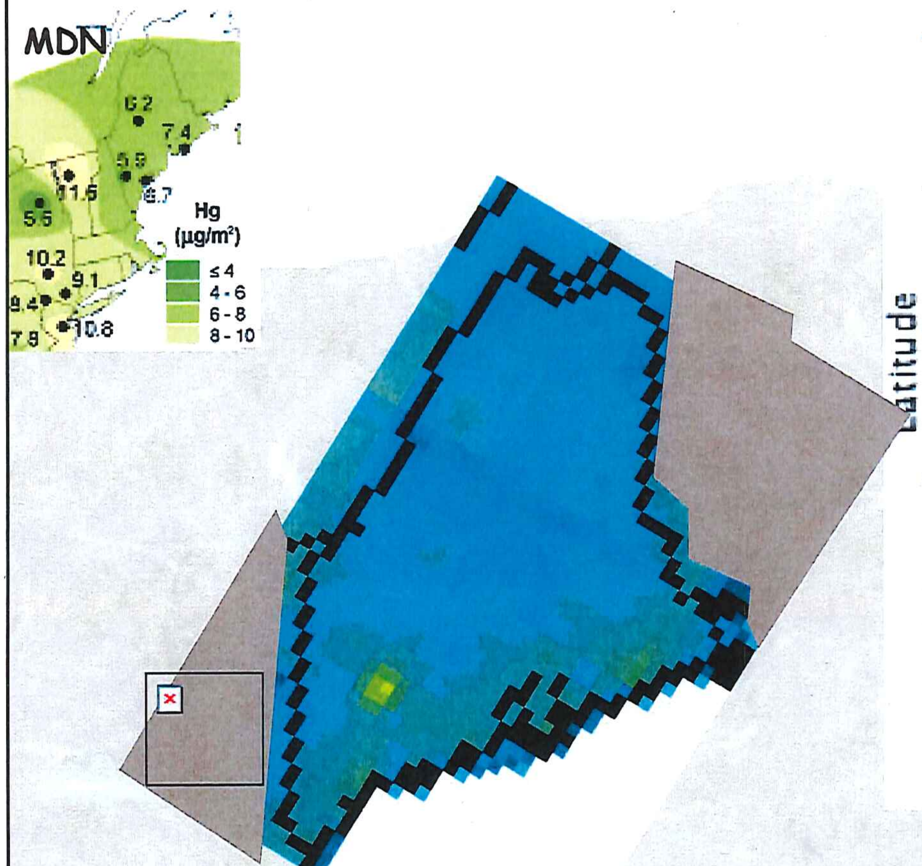
(Harris et al. 2006)

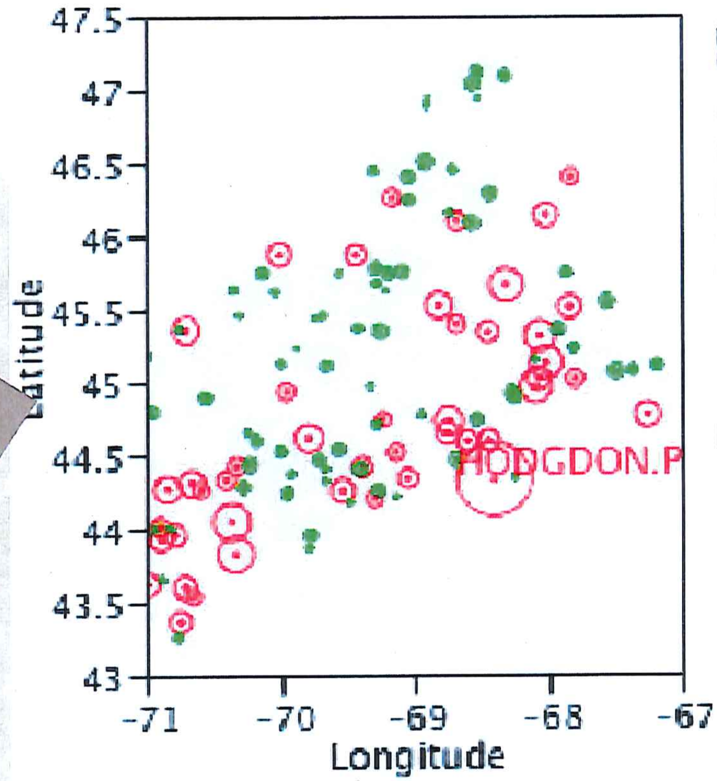

The Mercury Cycle and the EPRI Mercury Cycling Model
Wet and dry deposition
Volatilization of Hg(0)
Outflow
Inflow/Runoff
Reduction
Oxidation
Hg(0)
Photodegradation
Hg(II)
MeHg
Sediment/Water Exchange
Sediment/Water Exchange
Hg(II)
MeHg
Burial
Bioaccumulation
Burial
(Harris 2005, Hudson et al 1994)

Microbial Transformations of Hg are Significantly Influenced by Lake Characteristics



Similar deposition inputs do not always correspond to fish levels of mercury



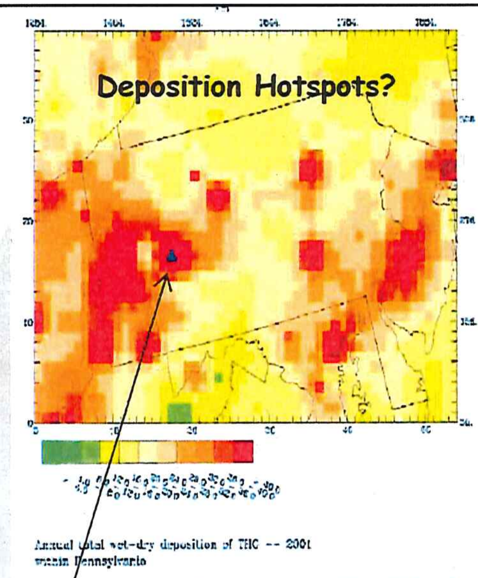


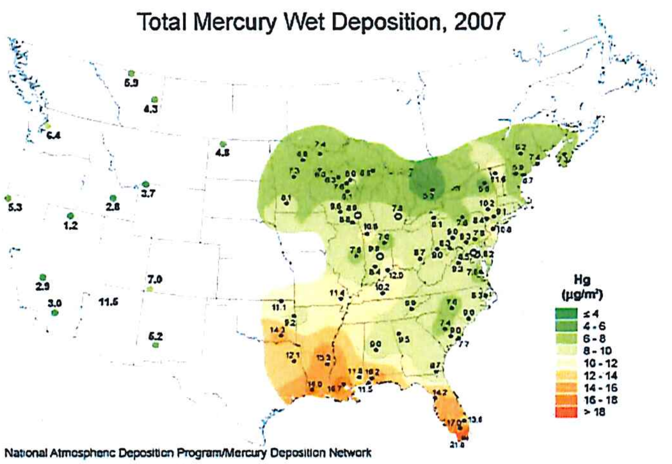
Total deposition of mercury (ug/m2/y)

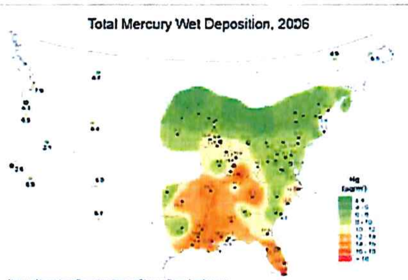
Red circles are proportional to fish Hg_{TOT} exceedance levels over 0.5 ppm

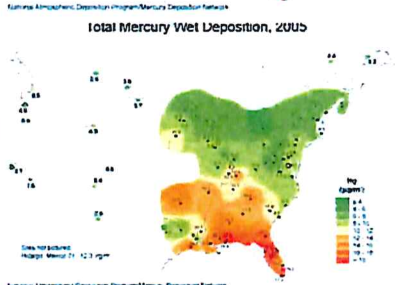
(EPRI Mercury Model, 2004 global inventory; L Levin,pers comm 11/08)

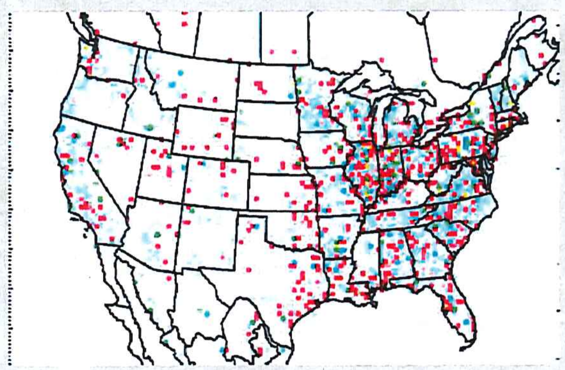
Are there deposition Hotspots?











Yet to be confirmed
by measurements

*(Driscoll et al 2007, as cited in ICL Petition 2008)

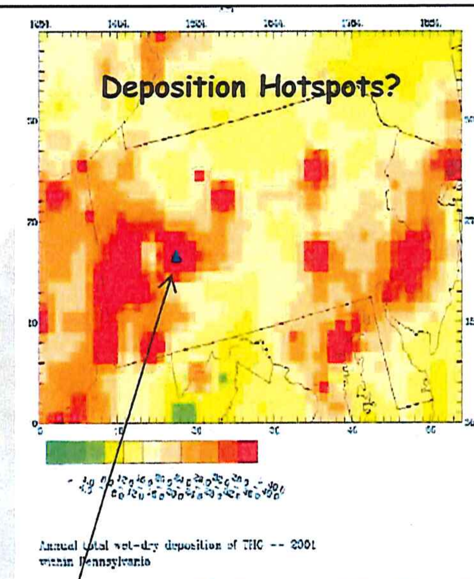
Are there deposition Hotspots?

*Mercury Matters, HBRF**

<u>Biological</u> Mercury Hotspots:

Areas where elevated concentrations of methylmercury occur in fish or other wildlife

Exhibit elevated Hg because these systems have characteristics conducive to bioaccumulation of MeHg



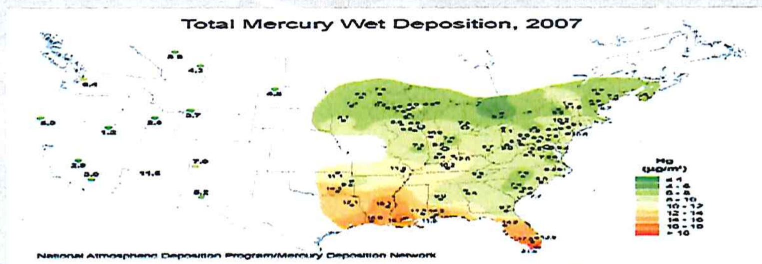
Yet to be confirmed by measurements

*(Driscoll et al 2007, as cited in ICL Petition 2008)

Recent USGS Analyses of National Trends

Mapping Modeled Vulnerability to Mercury Loading using Nationally Available Datasets*

The resulting Hg **vulnerability map** shows strong spatial trends in the eastern U.S., with the **highest vulnerability** along the **Gulf** of Mexico and **Atlantic coasts**, in the **Adirondacks**, and in the **Great Lakes** region. The **western** U.S. has some watersheds with **high** predicted **vulnerability**, but **no** geographic **pattern** is evident.

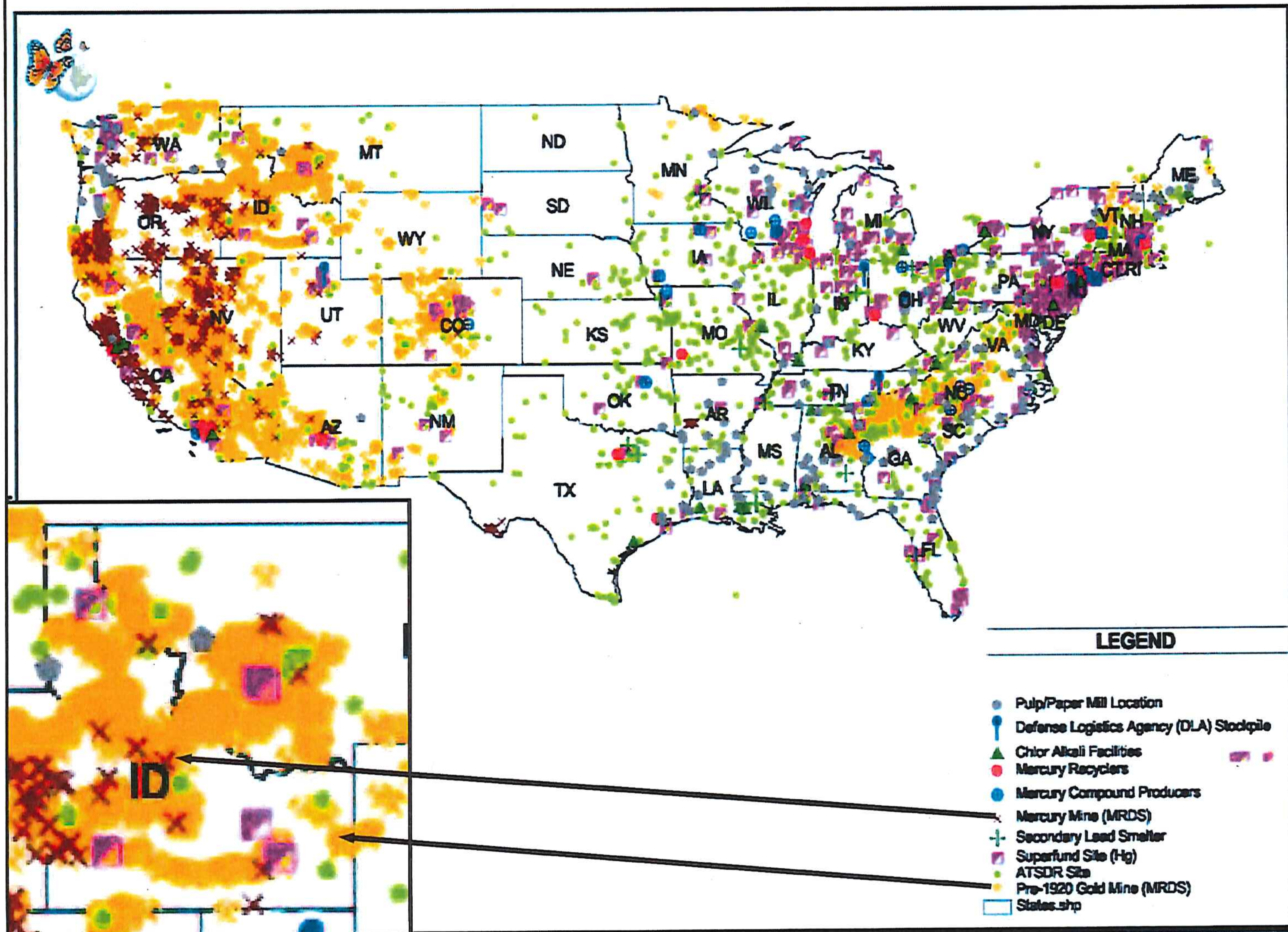


Mercury in Stream Water, Sediment, and Fish from a National Survey**

The **highest** concentrations in **fish** among all sampled sites occurred in **tannic**, **blackwater** coastal-plain streams of the **eastern** US and **western mining affected sites**. Several **blackwater** coastal-plain **streams** had **MeHg** concentrations that were **similar** to those of **mining-affected sites**, even though **THg** concentrations were much **lower**. This difference in the ratios of MeHg to THg highlights the **importance** of **methylation** as a **controlling** factor in the **bioaccumulation** of mercury in fish.

(*Nathaniel et al, USGS and EPA; **Scudder et al USGS; 8th Conf. on Hg as a Global Pollutant, 2006)

The Unique West- the role of mining



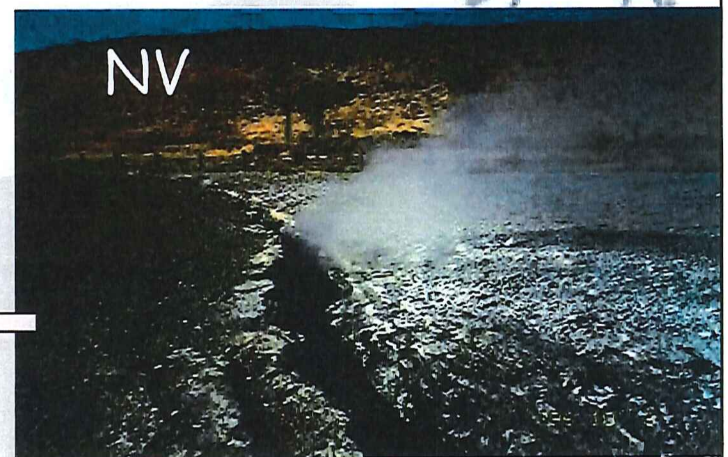
Air Pollution Control Engineering

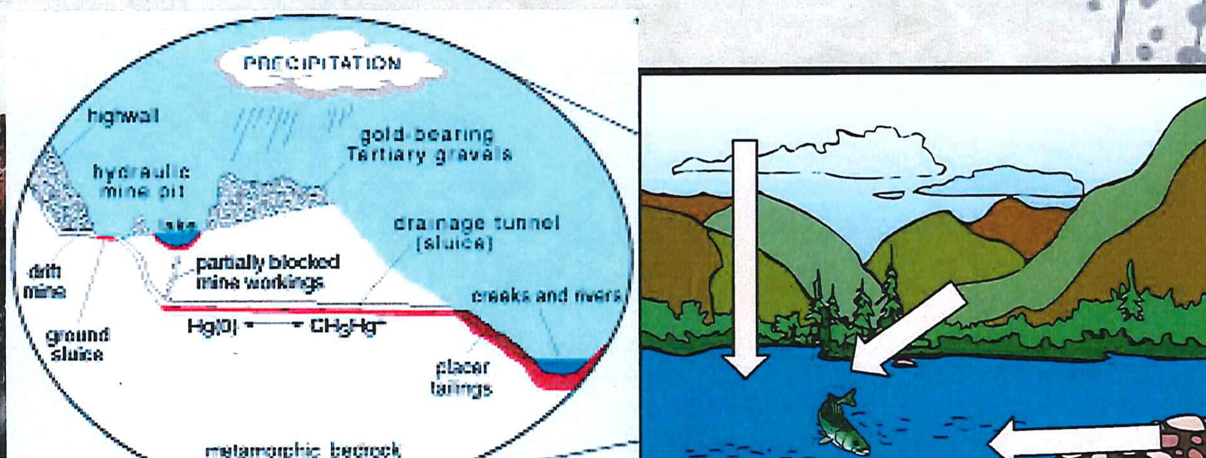
UNIVERSE OF SITES WITH POTENTIAL MERCURY CONTAMINATION IN THE UNITED STATES

FIGURE 1.1

Natural geological occurrences of Hg are not just *atmospheric* sources

Groundwater and soils





(USGS 2007)

LAS VEGAS SUN

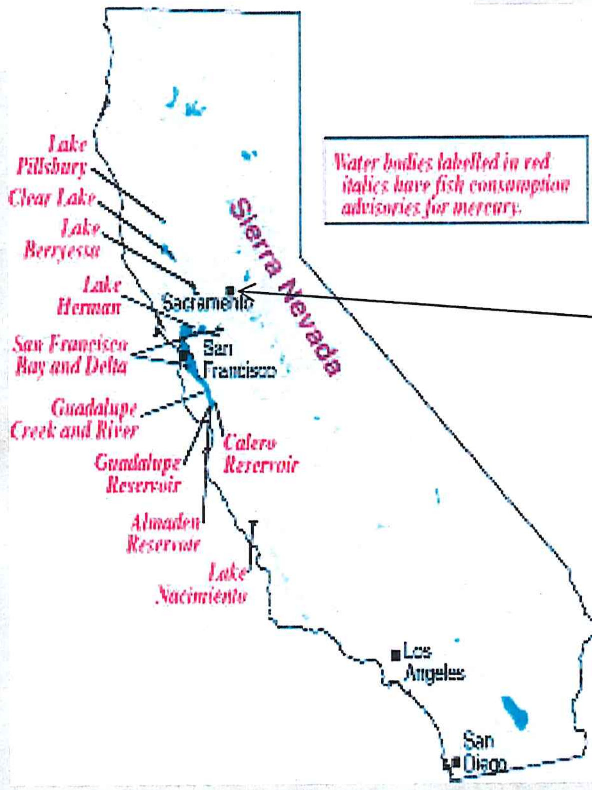
Jan 27, 2009 ENVIRONMENT:

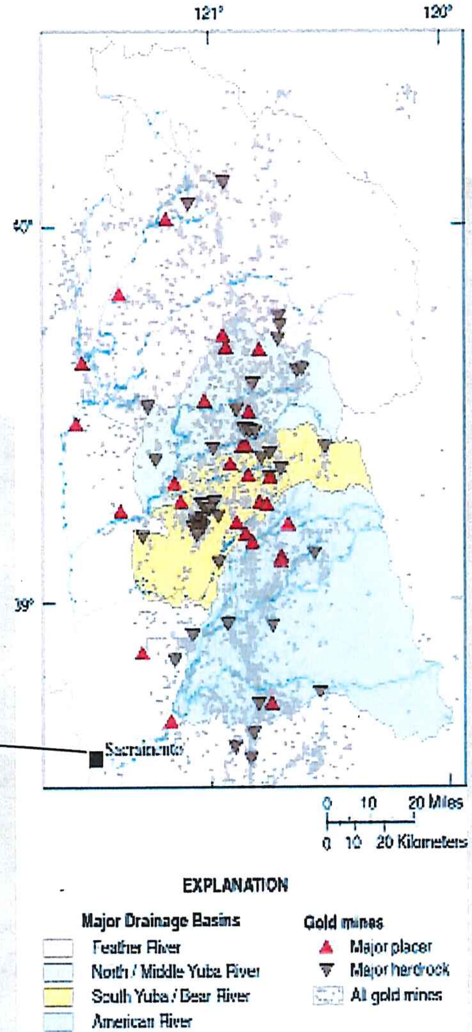
EPA allegations spark call for checks on state's mines

Environmental groups cite worry about mercury contamination

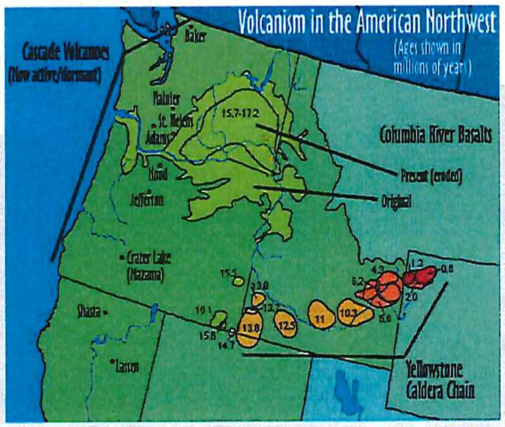
"...polluting ground water and soil."

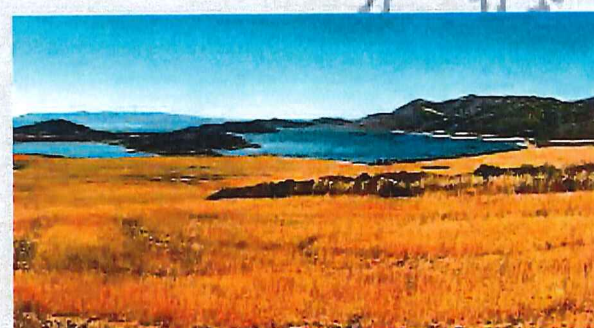
Numerous examples of western waters affected by Hg from historic gold mining:

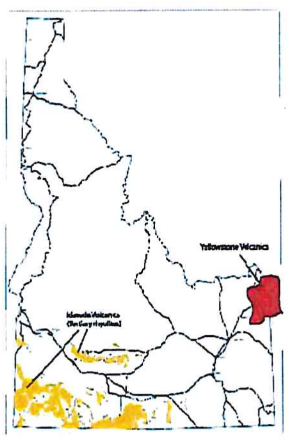




Natural geological occurrences of Hg are not just *contaminated* sources







Young Silicic Volcanic Rocks in Idaho

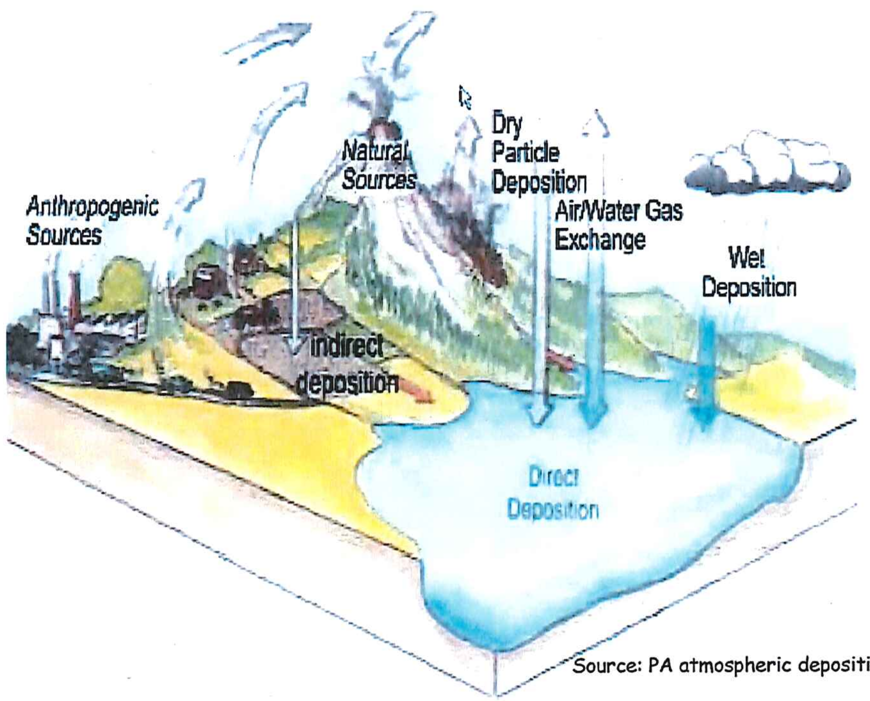
Yellowstone area hot springs are also potential mercury source.

Idaho Geological Survey

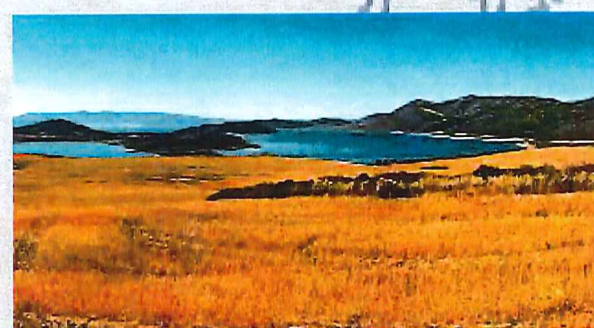
January 2009

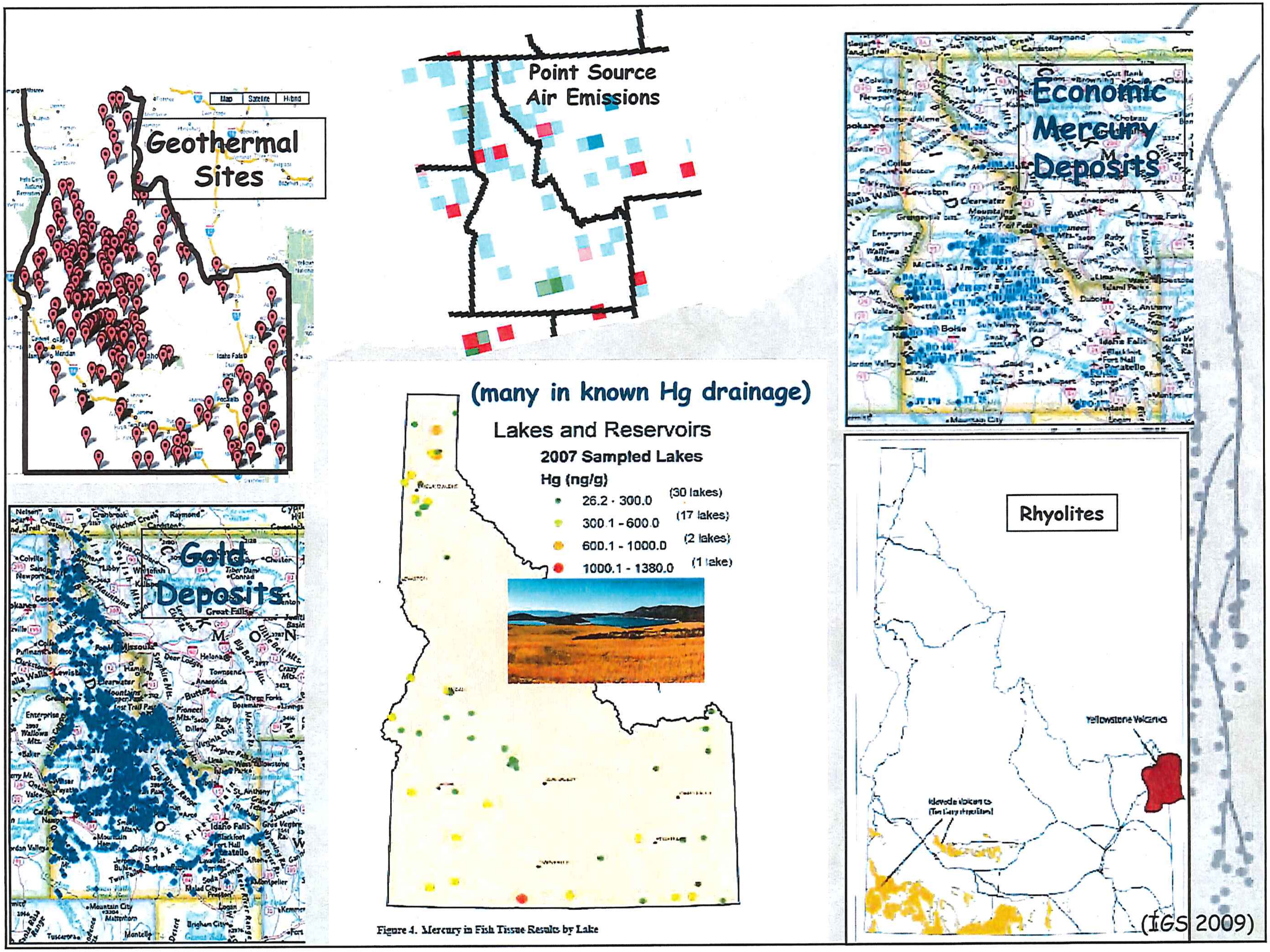
Natural geological occurrences of Hg are not just *contaminated* sources

Now consider the distribution of atmospheric & geologic Hg sources in Idaho

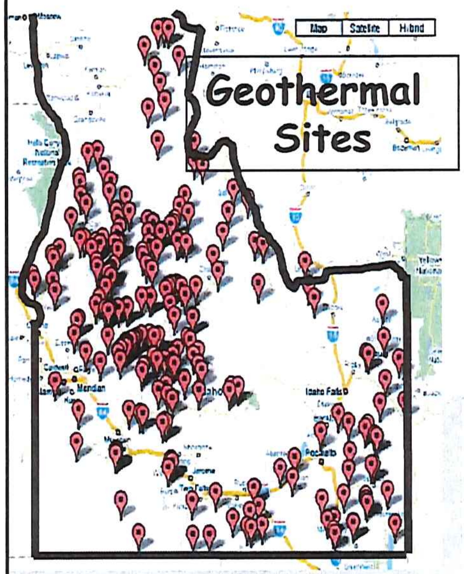


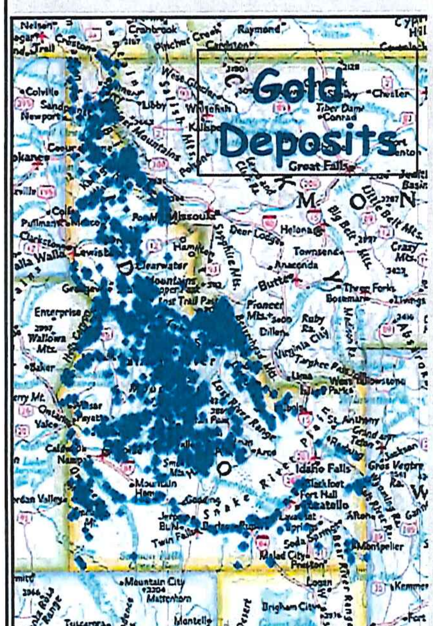
Source: PA atmospheric deposition handbook.




Geothermal Sites
Point Source Air Emissions
Economic Mercury Deposits
Gold Deposits
(many in known Hg drainage)
Lakes and Reservoirs
2007 Sampled Lakes
Hg (ng/g)
26.2 - 300.0 (30 lakes)
300.1 - 600.0 (17 lakes)
600.1 - 1000.0 (2 lakes)
1000.1 - 1380.0 (1 lake)
Figure 4. Mercury in Fish Tissue Results by Lake
Rhyolites
Yellowstone Volcanics
(IGS 2009)

Many other mercury sources in Idaho, and they are mostly in the ground





(many in known Hg drainage)

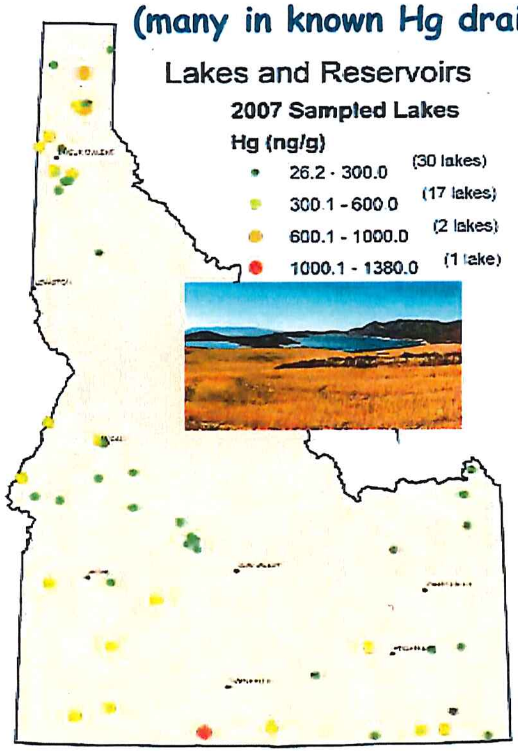
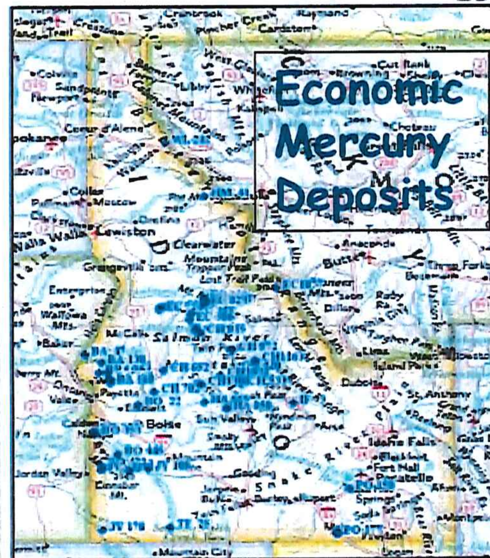
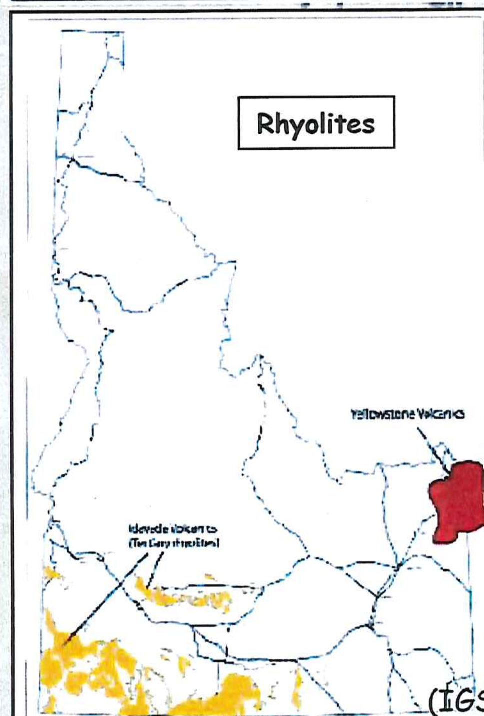
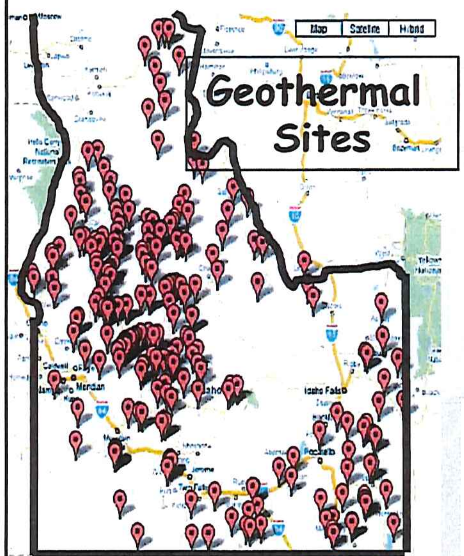


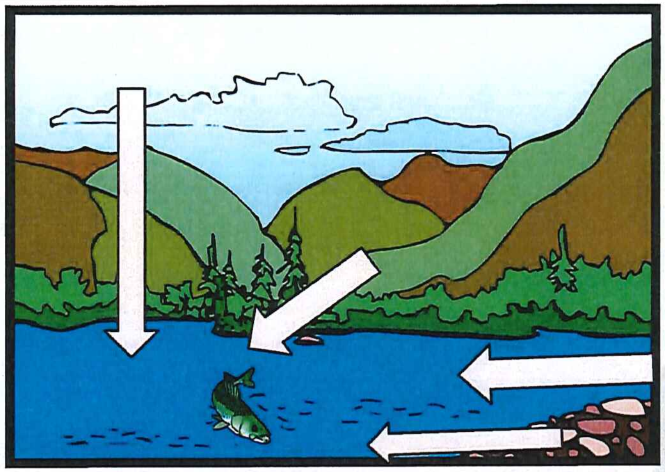
Figure 4. Mercury in Fish Tissue Results by Lake

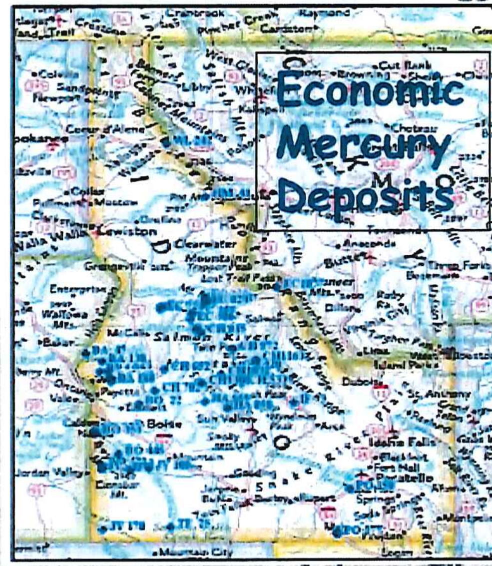


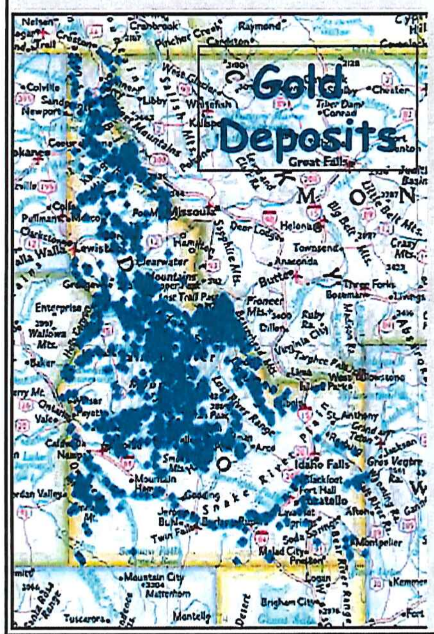


(IGS 2009)









(many in known Hg drainage)

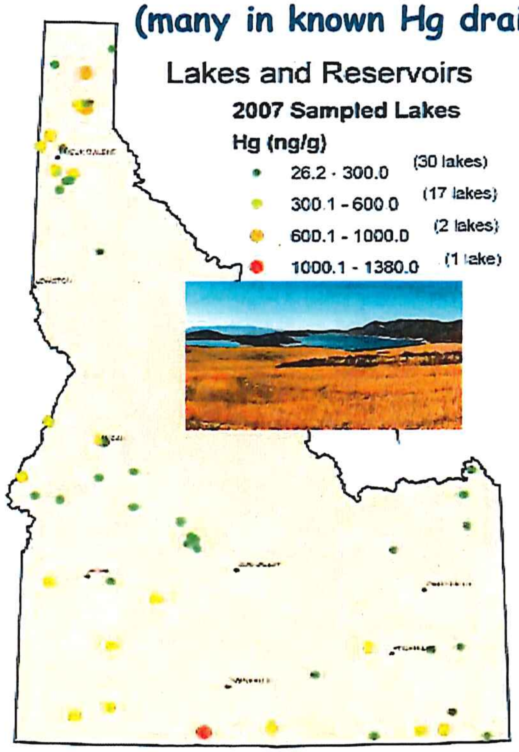
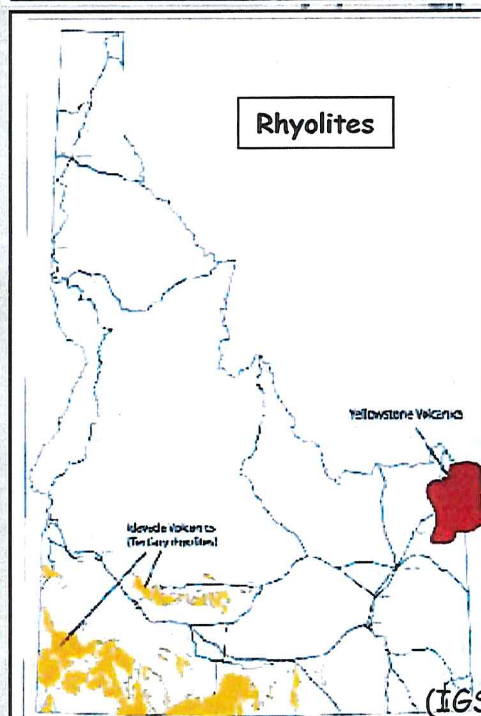


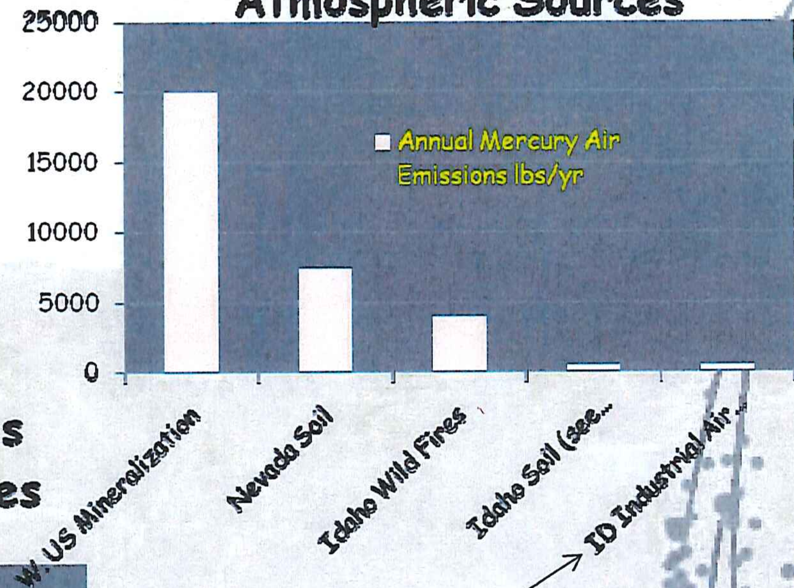
Figure 4. Mercury in Fish Tissue Results by Lake



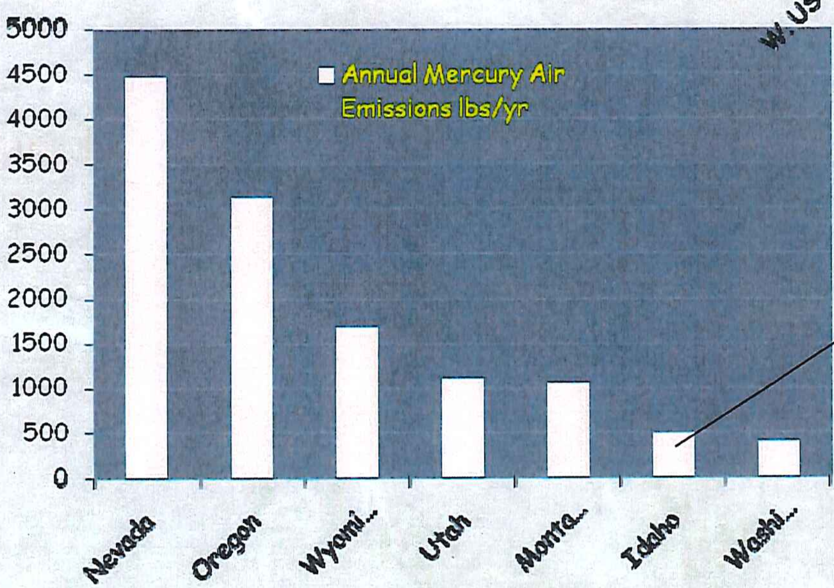
(IGS 2009)

Placing Idaho industrial air emissions into perspective

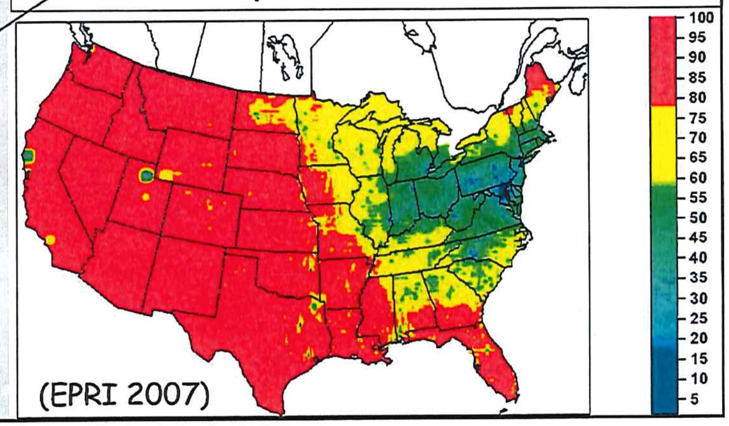
Idaho Industry vs Natural Atmospheric Sources



Annual Mercury Air Emissions for Idaho and Adjacent States

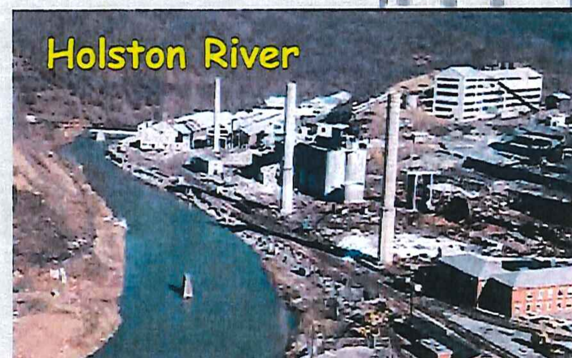


% contribution to deposition by non-U.S. sources



But isn't it true that reducing *atmospheric* deposition of mercury has reduced mercury in fish?

Lake Onandaga, Lavaca Bay, New River, Pinci Lake, Squamish Bay, Poplar Creek, Holston River, Minamata Bay

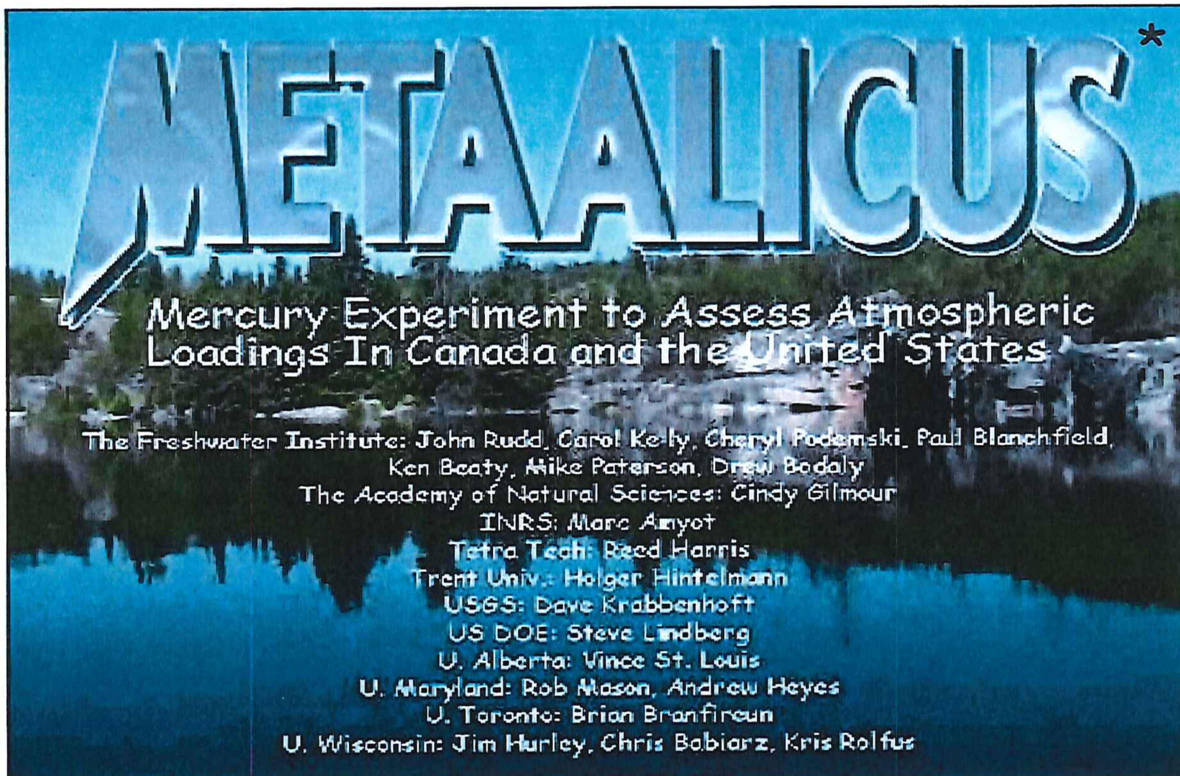


Expert Panel on Recovery of Fisheries*

"Evidence to support recovery comes mainly from aquatic **systems affected by point source discharges** directly into waters."

"For responses to **changes in atmospheric deposition, are very few** cases, limiting the possibilities to draw firm conclusions."

*(Munthe et al 2007)



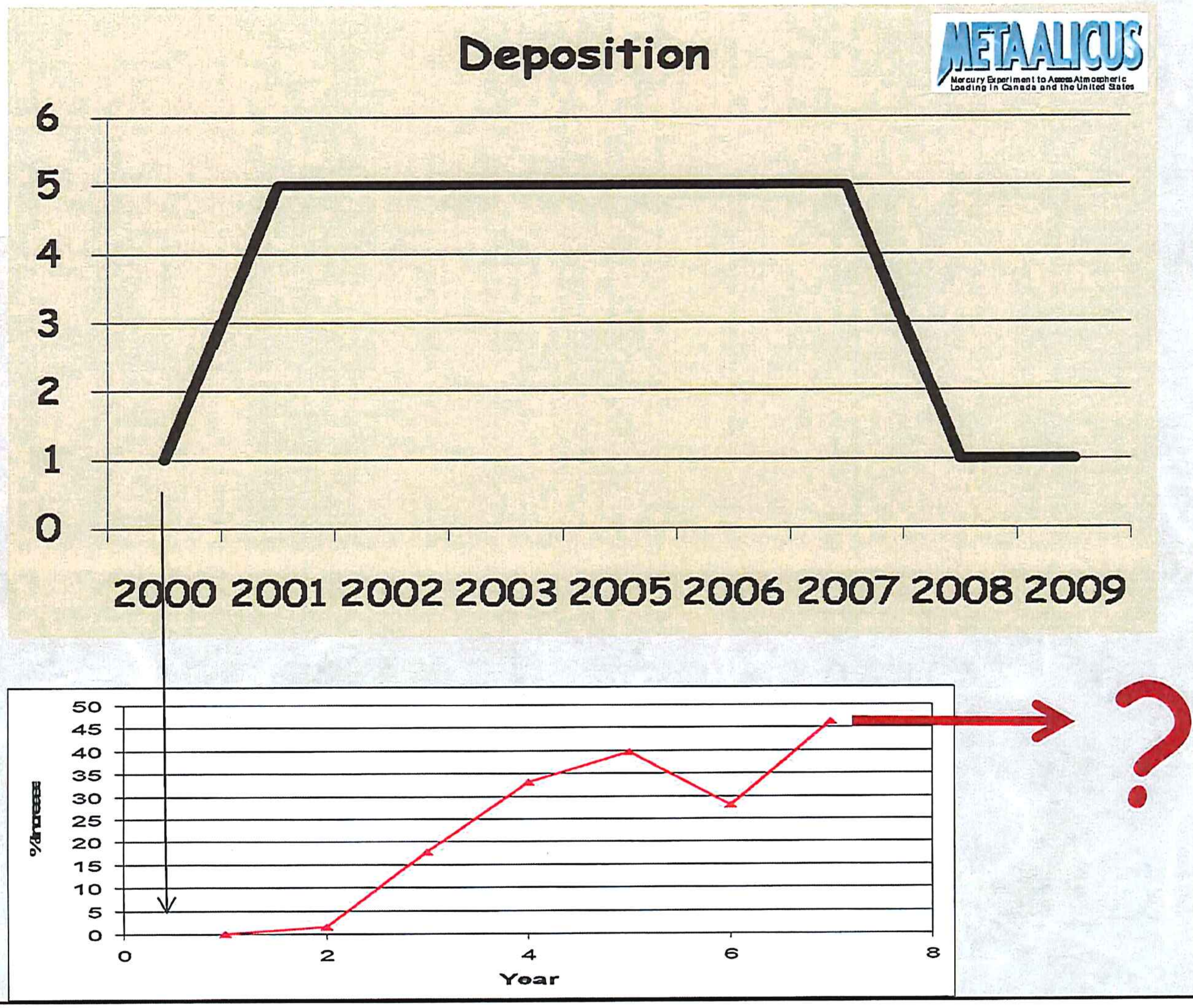
Designed to simulate atmospheric deposition, but results also apply to any increased input of HgII

^{202}HgII

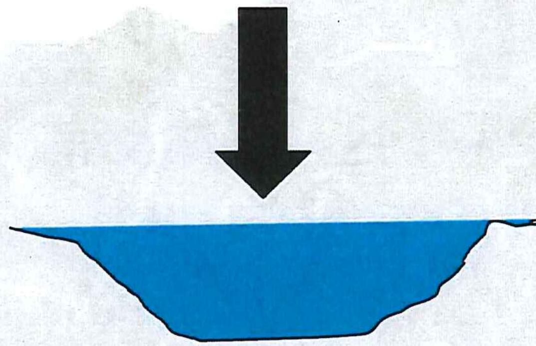
^{200}HgII

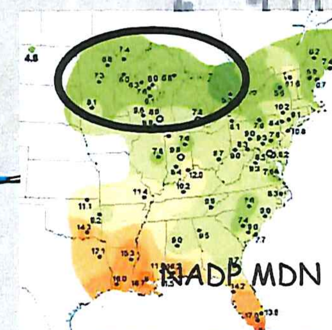
*(Harris et al 2007, as cited in ICL Petition 2008)

Response of fish to reduced atmospheric deposition of mercury has yet to be measured. Expectation is there, but reality not yet established.

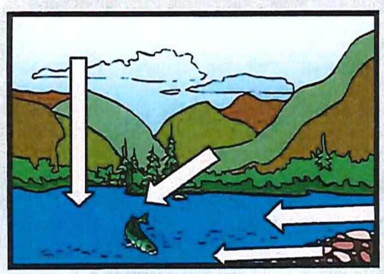


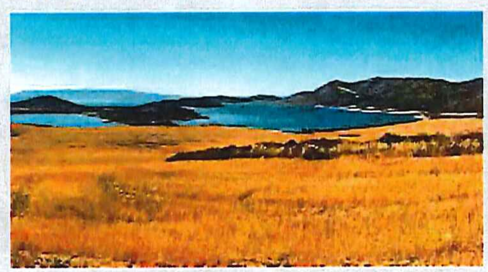
But doesn't everyone say that *atmospheric* deposition of mercury is the problem?





Western reservoirs and lakes are different



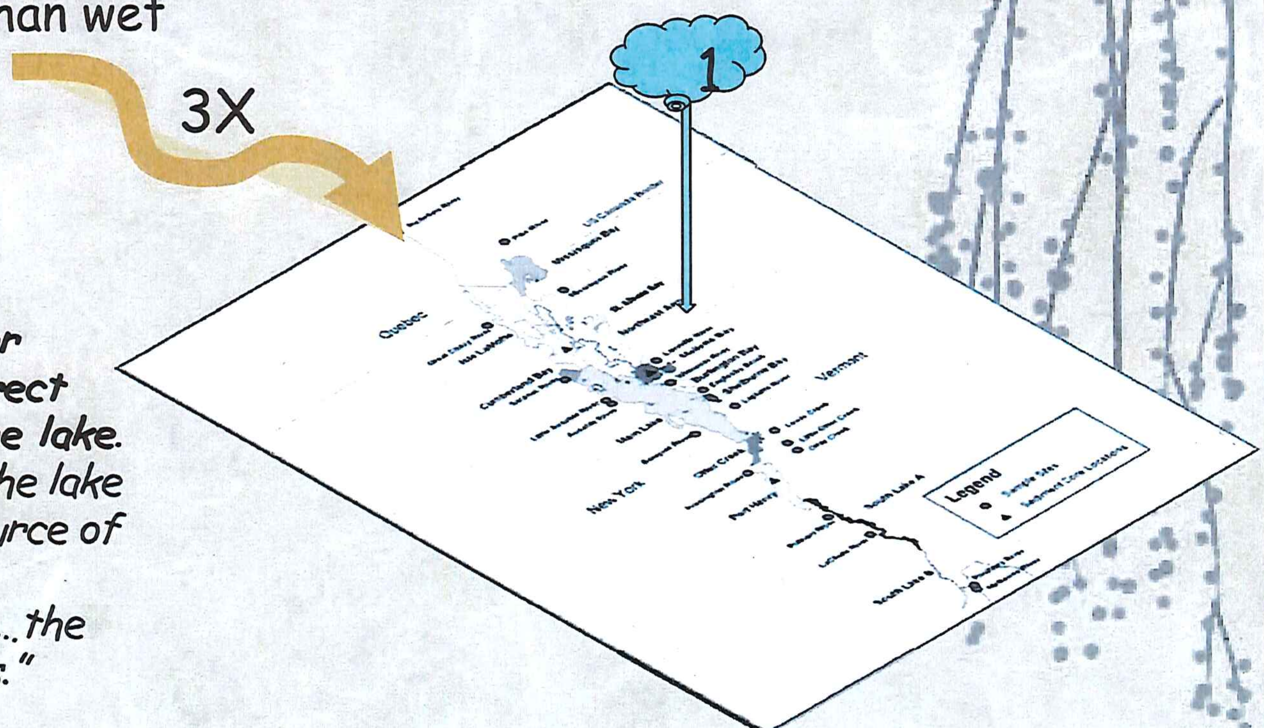


Recent studies of atmospheric deposition vs inflow

Article

Mass Balance Assessment for Mercury in Lake Champlain*

Annual inflow of Hg was 3 times larger than wet deposition.



"...identified surface water inflows as the largest direct contributor of Hg into the lake. Direct wet deposition to the lake was the second largest source of Hg ... Volatilization and sedimentation losses were... the major removal mechanisms."

*(Gao et al 2006)

Recent mass balance study of atmospheric deposition vs inflow in Idaho

Salmon Falls Creek Subbasin: Mercury Monitoring Report & TMDL*

- **Field measurements to estimate annual mass balance:**
  - Streamflow & water column Hg sampling
  - Wet deposition sampling
  - Dry deposition estimates from measured air concs (Mike Abbott, INEEL)

- Annual mass balance indicates the **dominant contribution of Hg** to this reservoir **is inflow, contributing ~85% of total**

- Direct **wet deposition** contributed **~5%**

- **Sources** originated in **streamload**; atmospheric? geologic?

*(Lay 2006, IDEQ)

Recent studies of atmospheric deposition vs inflow in Idaho

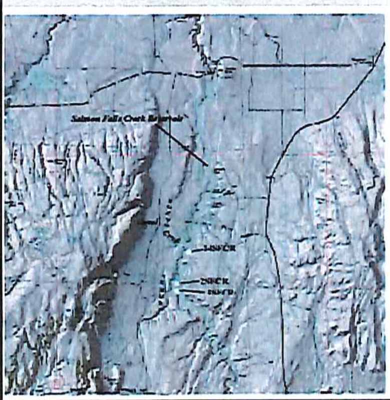
Evaluation of Trends of Mercury Deposition in Salmon Falls Creek Reservoir, Idaho, using Reservoir Sediment Cores*

- Data suggest the **dominant contribution of Hg** to sediments in this reservoir is from **lithologic sources, such as soil and bedrock**, derived upstream. Enrichment factors support a lithologic source

- **Unlikely** that increases in **Hg accumulation** rates are **related** to **deposition** from any significant external source of Hg, such as **atmospheric Hg**,

- Any **atmospheric** Hg is a **lower** contribution compared to the **sediment** load in SFCR,

- A significant **point source** of Hg was **not identified** in the sediment



Biogeochemical methylation in SFCR

- SFCR exhibits a high methylation rate

- MeHg derived from the sediment, delivered to the water column

(*Gray 2006, **Gray & Hines 2009)

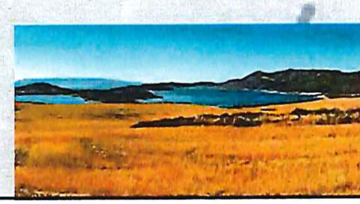
US Geological Survey studies of mercury in reservoir sediments

1. Assessing Bottom Sediments as a Source of Mercury Contamination: *fish bioaccumulating mercury from contaminated sediments from gold mines: significant percentage of mercury in reservoir water from the bottom sediments.**

2. Mercury Benthic Flux: A Comparison Between 3 Mining-Impacted Water Bodies in the Western United States: *benthic Hg fluxes similar or greater than riverine loads: Interactions bottom sediment Hg and overlying water consistently important, and be considered when targets developed for remediation and restoration.*

3. Effects of Benthic Flux on Dissolved-Mercury Distributions in Camp Far West Reservoir, California: *Diffusive transport dissolved, bioavailable mercury between reservoir bed and water column most important process regulating the concentration of mercury in water.*

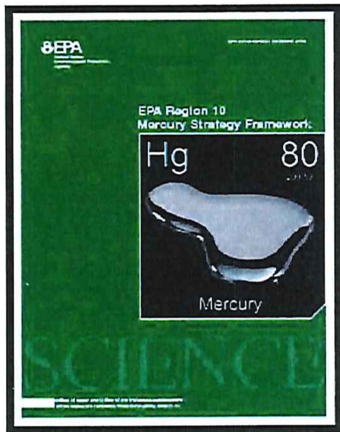
In many western waters existing mercury in sediments results from geological contributions



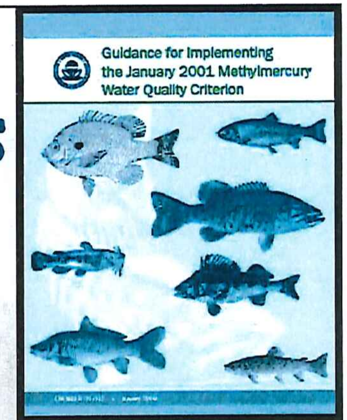
*(Kuwabara et al 2000, Kuwabara et al 2003, Topping et al 2004)

Summary

- Numerous pathways for Hg to enter Idaho waterways
- The geology & climate of the West present unique issues for Hg
- Industrial emissions in Idaho are comparatively small
- Modeling is useful, but its limitations must be understood
- REMSAD over-predicts the local impact of industrial air emissions (eg P4 by >10X)
- Methyl mercury influenced by reservoir chemistry & hydrology in addition to mercury inputs
- Geologic Hg deposits are ubiquitous in Idaho
- Deposition not the only route of Hg entry to Idaho waters
- Inflow and sediment transport may dominate atmospheric deposition of Hg to some western waterways
- Numerous sources of Hg to Idaho waterways; most are probably in the ground
- Cannot assume an *a priori* link between the atmosphere and methylmercury in fish throughout Idaho
- Additional regulation of existing Idaho industrial atmospheric sources may achieve little if any reduction in fish methylmercury



EPA TMDL guidelines on sites impacted by mining-related and natural Hg loads



"Mercury loadings predominantly from past mining activity, with small or no contributions from atmospheric deposition and/or NPDES point source contributions"

- **Example TMDL- Cache Creek Watershed (California)**

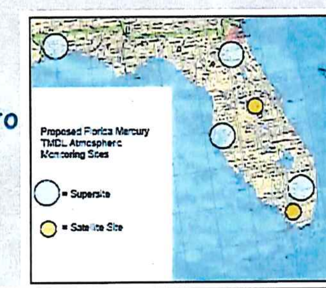
- **Hg sources**: leaching from waste rock and tailings from **historical mercury** and gold mines, erosion of **naturally mercury-enriched soils, geothermal** springs, and atmospheric **deposition**.

- **Atmospheric Hg contributions**: direct **deposition** and deposition runoff **very small** compared to loads from **mine** sites or **erosion** of stream bed and banks, and **thus no allocations are made to air deposition**.

Newest TMDL study, Florida DEQ 2009:*

- 2-y deposition measurement effort to **identify all Hg sources** to waters, with modeling of atmospheric sources & their **contribution to fish methylmercury** (GEOSCHEM, CMAQ)

- **Cost >$4M**



*(Keeler et al 2009)

Mercury does impact Idaho waters, but the current focus is not properly directed