

Mercury Control Technologies for Electric Utilities Burning Lignite Coals



*Project Kickoff Meeting
February 28, 2002*

Page 1 of 49

Kickoff Meeting Agenda – 2/28/02

- Welcome/Introduction 8:30 A.M.
- Project Overview/Background 9:00 A.M.
- Break 10:00 A.M.
- Phase I – Bench-Scale Testing 10:30 A.M.
- Phase I – Pilot Scale Testing 11:00 A.M.
- Project Schedule 11:30 A.M.
- Open Discussion 11:45 A.M.
- Lunch 12:00 P.M.
- Tour 1:00 P.M.
- Adjourn 2:30 P.M.

*Mercury Control Technologies for Electric
Utilities Burning Lignite Coals*

Overview

Multi-Client Project Sponsors/Participants

Canada

- Saskatchewan Power
- Environment Canada
- Ontario Ministry of the Environment
- Luscar Ltd.

United States

- Basin Electric Power Cooperative
- Minnkota Power Cooperative, Inc.
- Otter Tail Power Company
- EPRI
 - Great River Energy
 - Excel Energy
 - Minnesota Power, Inc
- North Dakota Industrial Commission
- U.S. Department of Energy

Background – Mercury Regulations Canada

- Undergoing a consultative process for developing “Canadawide Standards” for mercury emissions from coal-fired electricity generation
- An inventory of emissions in Canada indicates that 6 sectors (base metal smelting, coal fired power generation, hazardous waste, biomedical, municipal and sewage sludge incineration) account for 80% of Canada’s emissions. These six sectors are being considered for standards development.

Mercury Sources in Canada

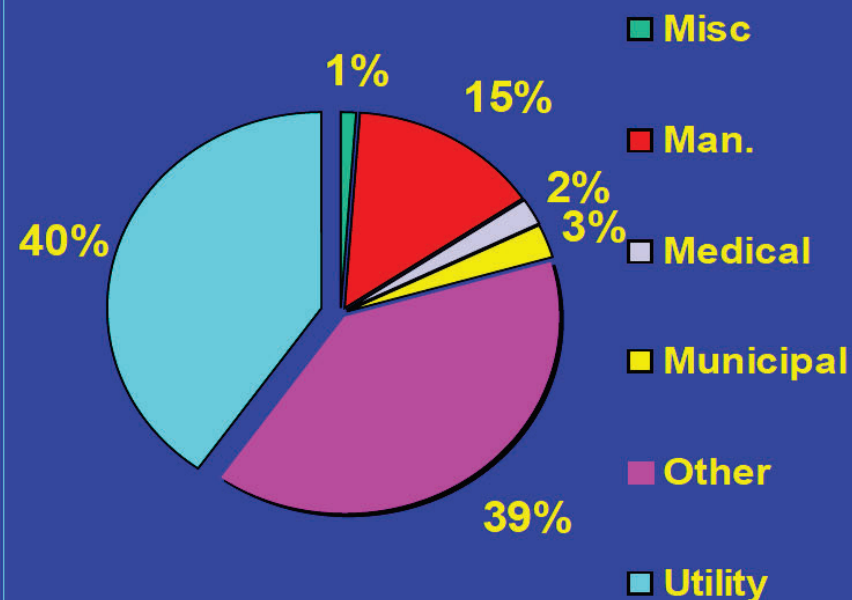
Sector	Est. 1995 releases (tonnes)	Reduction technologies available? ¹	Sector standards in N. America?
Base Metal Smelting	4.95	Yes	Yes
Incineration (total 4.6 tonnes)			
Municipal Solid Waste	2.24	Yes	Yes
Hazardous Waste	1.44	Yes	Yes
Biomedical Waste	0.49	Yes	Yes
Sewage Sludge	0.43	Yes	Yes
Electrical Utilities and Non-Utility	1.17	Yes	No
Fuel Combustion	0.80	No	No
Chemical Industry (water)	0.49	Unknown	Yes
Iron and Steel	0.47	Unknown	Yes
Fluorescent Tube Breakage ²	0.41	Yes	Yes

1 includes alternative fuels and processes.

2 tube breakage prior to landfilling is the largest estimated direct source of emissions from products - other products also emit mercury during their lifecycle through incineration or disposal.

Mercury Sources in the United States

Source Category	Mercury Emission, Tpy
Miscellaneous	1
Manufacturing	15
Medical Waste Combustion	2
Municipal Waste Combustion	3
Other Combustion	40
Coal-fired Utility Boilers	41



Background – Mercury Regulations United States

- Maximum Achievable Control Technology (MACT) Standards
 - Section 112, National Emission Standard for Hazardous Air Pollutants (NESHAP)
 - Mercury is the Hazardous Air Pollutant (HAP) of greatest concern, however other HAPs may be included: Trace elements (Sb,As,Be,Cd,Cr,Co,Pb,Mn,Ni,Se), Halogens (hydrogen chloride, hydrogen fluoride), Dioxins, Furans, etc.
- Multi-pollutant Proposed Legislation
 - Jeffords (S556 [*Clean Power Act of 2001*]), 90 % reduction, no trading, January 2007
 - Leahy (S1131 [*Clean Power Plant and Modernization Act of 2001*]), 90 % reduction, some trading allowed, within 10 years of enactment
 - Allen (HR1335 [*Clean Power Plant Act of 2001*]), 90% reduction, no trading, January 2005
- **Clear Skies Initiative**

Mercury Regulations U.S. (continued)

EPA MACT Approach

- EPA announced decision to regulate on December 14, 2000
- Announced that coal- and oil-fired electric steam generating units will be added as source categories for MACT standards
 - EPA must establish MACT “Floor”
 - Floor defined as the average emissions achieved by the best performing 12% of sources. Is ICR data adequate to establish floor? Short term measurement, not long term? Based on ICR data, the best 12% will result in 90+% reduction.
 - Mercury reductions vary from 0 to 99 based on ICR data depending on coal burned and unit type.
- Subcategorization is being considered based on coal type
- Schedule:
 - December 2003 - Proposed regulations
 - December 2004 - Final Regulations
 - December 2007 - Utilities will have to comply with requirements

3 Pollutant Control Strategy DOE Perspective

	Phase I	Phase II	Phase III
Hg	By 2008 Cap at 24 tpy	By 2012 Cap at 7.5 tpy Min. 70% red	N/A
SO ₂	By 2010 Cap at 2 Mtpy	N/A	N/A
NO _x	By 2004 SIP Call Comp.	By 2008 Cap at 1.87 Mtpy	By 2012 Cap at 1.25 Mtpy

The Clear Skies Initiative Bush Proposal

	2008	2010	2018
Hg	No reductions required	Cap at 26 tpy 45 % reduction from 48 tpy	Cap at 15 tpy Add 42 % 26 tpy Total 69 % of 48 tpy
SO ₂	Same as current	Cap at 4.5 Mtpy 60 % reduction from 11 Mtpy	Cap at 3 Mtpy Add 33 % of 4.5 Total 73 % of 11 Mtpy
NO _x	Cap of 2.1 Mtpy 58 % reduction from 5 Mtpy	Same as 2008	Cap of 1.7 Mtpy Add 19 % from 2.1 Total 69 % of 5 Mtpy

Announced 2/14/02

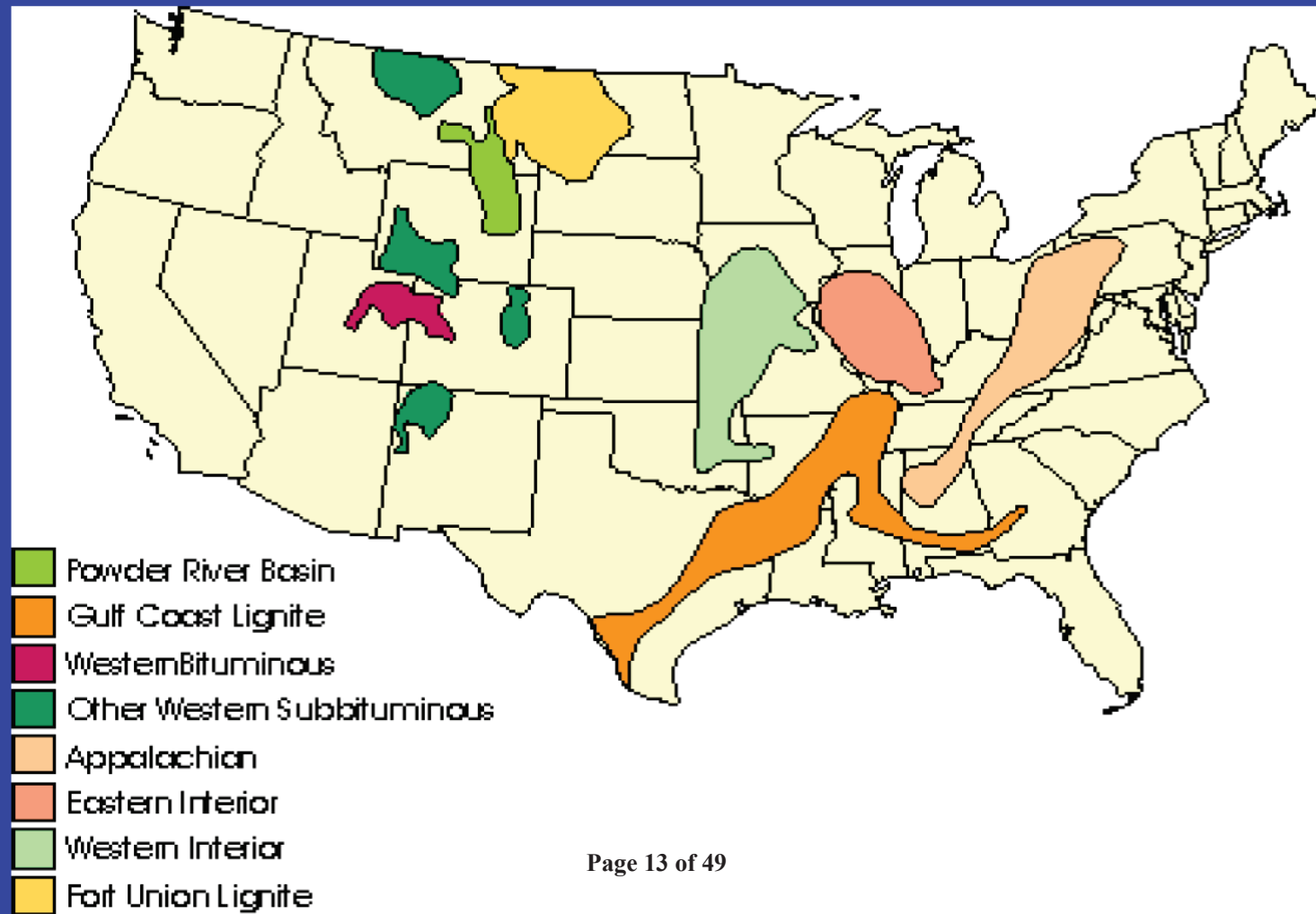


Summary of United States Proposed Mercury Standards

	2007	2008	2010	2012	2018
EPA MACT	50-90 % red No trade				
DOE		Cap at 24 tpy		Cap at 7.5 tpy Min 70 % red	
Jeffords Bill	90 % red No trade				
Leahy Bill				90 % red Limited trade	
Bush			Cap at 26 tpy 45% red Trading allowed		Cap at 15 tpy ~70% red Trading allowed

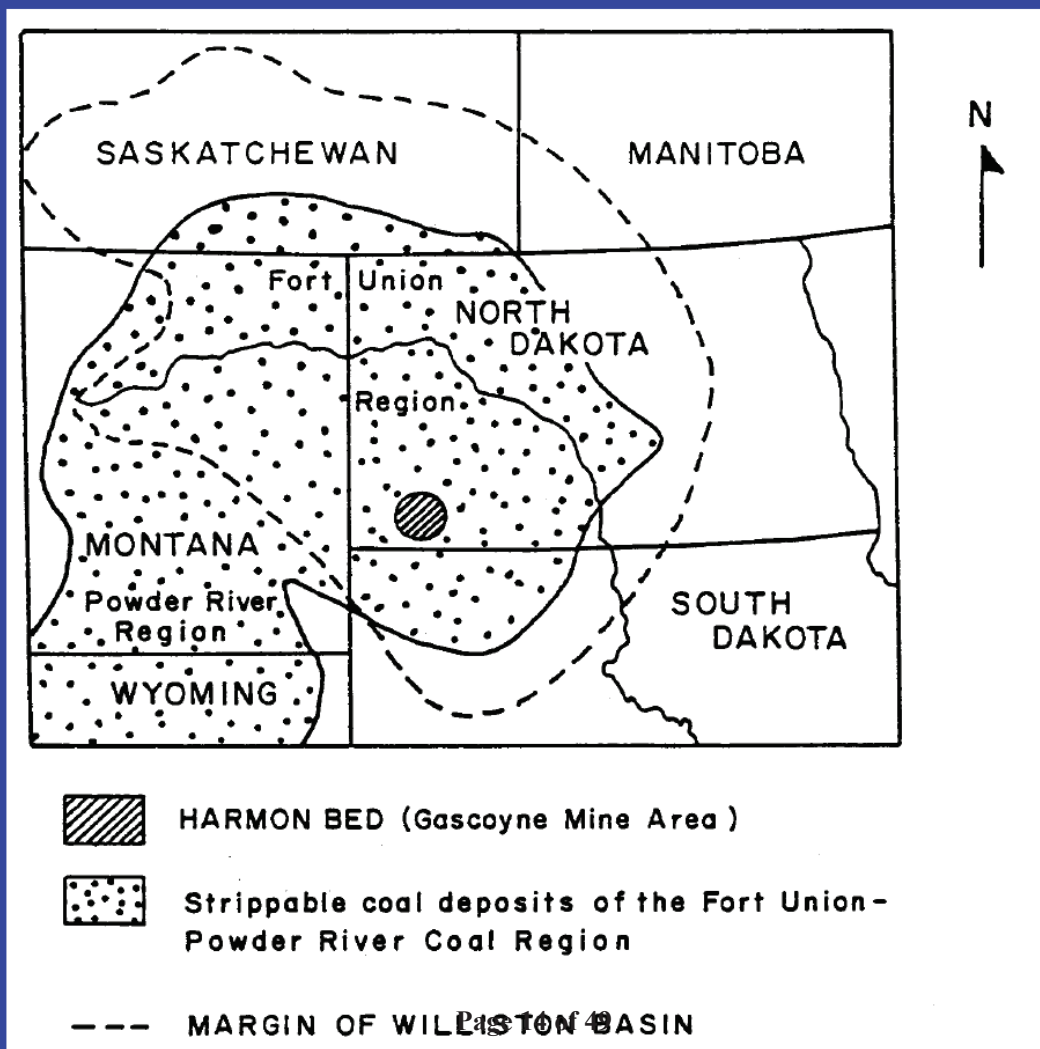
Background – Mercury in Coal

Map of Coal Basins

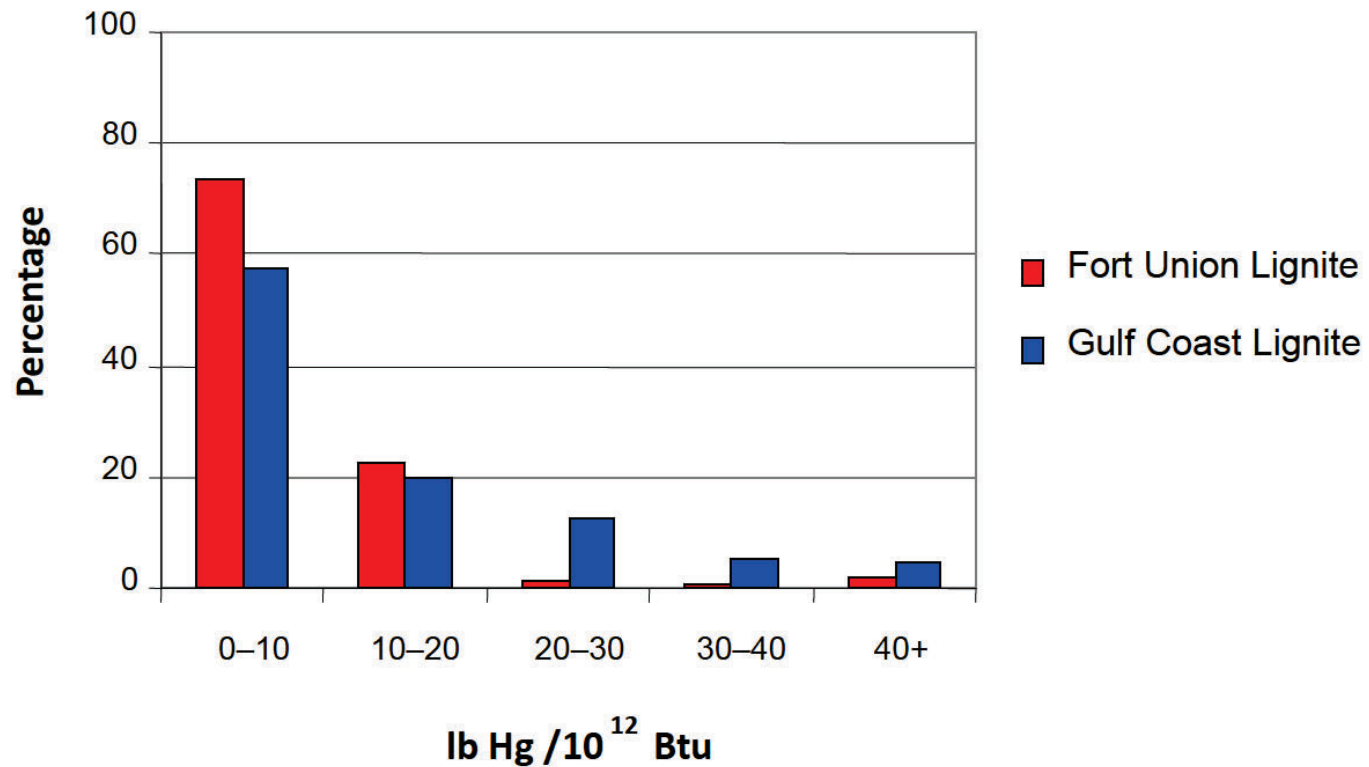


Page 13 of 49

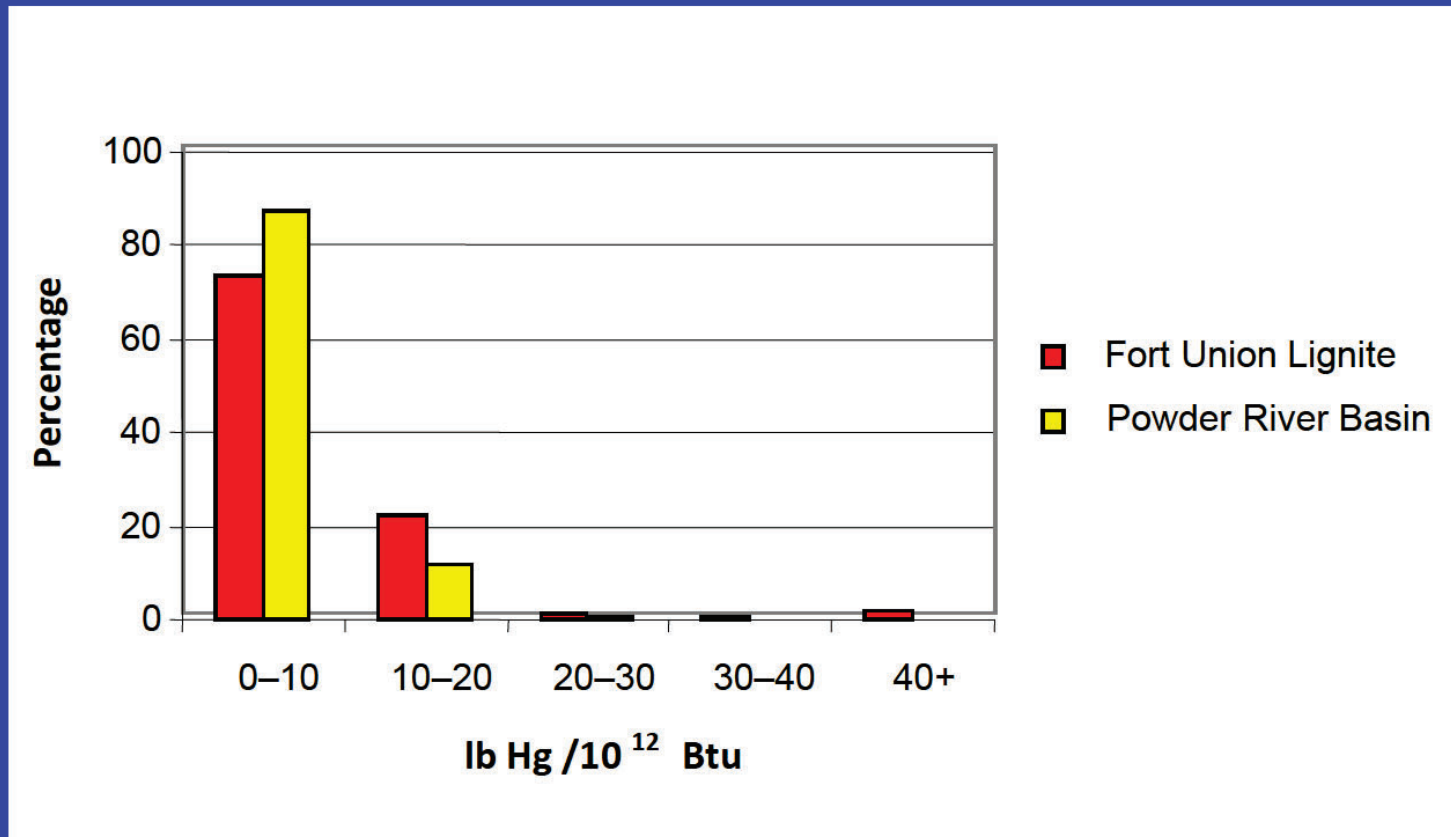
Fort Union Region



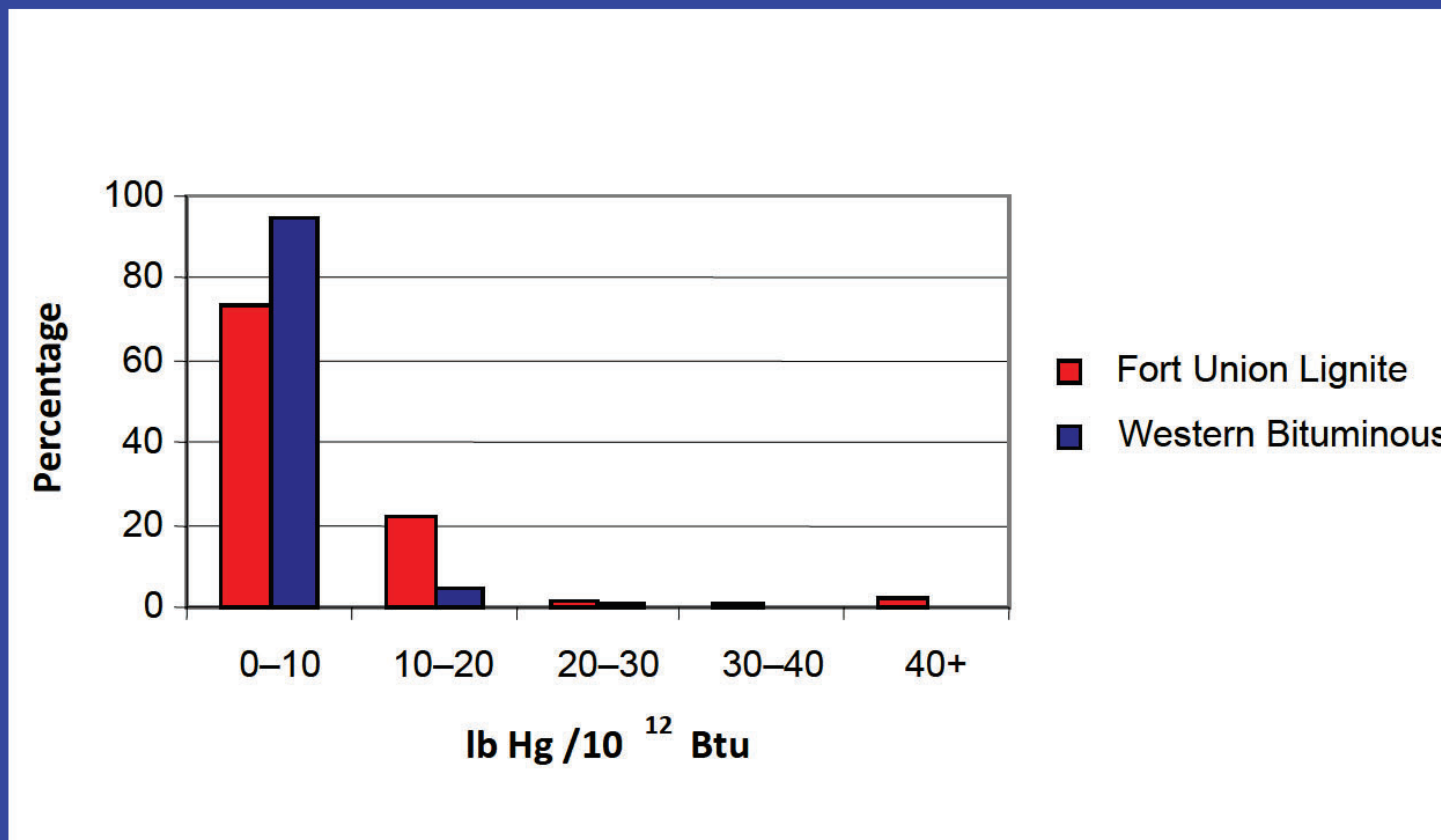
Fort Union Lignite Compared to Gulf Coast Lignite



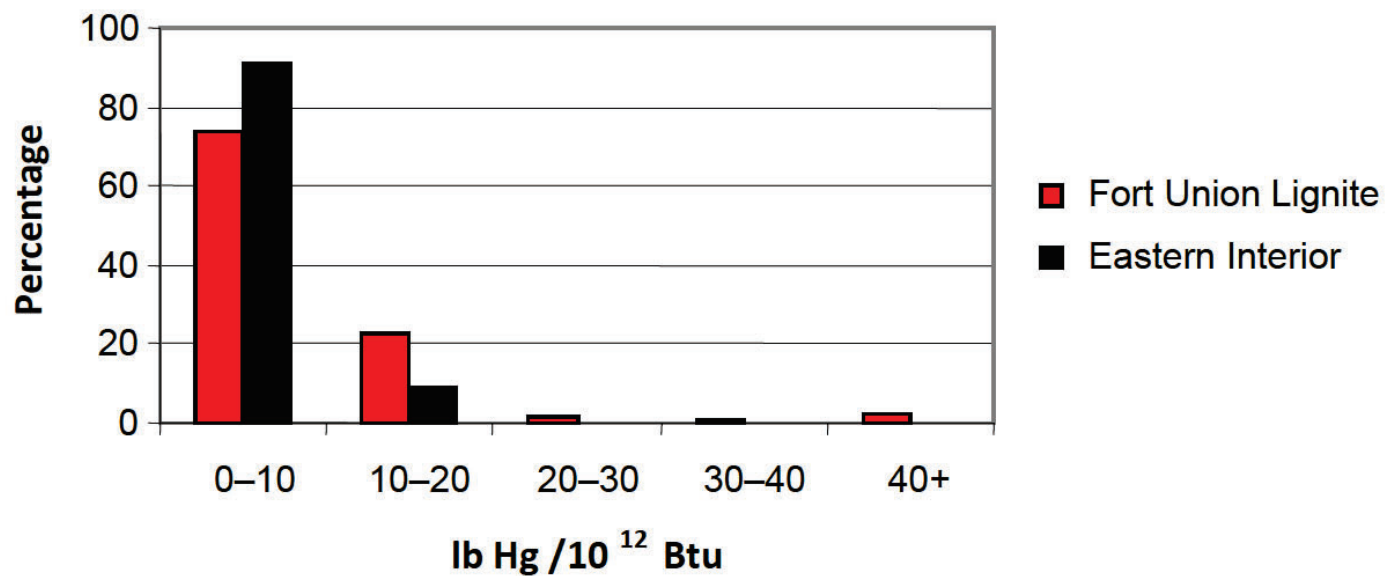
Fort Union Lignite Compared to Powder River Basin Coals



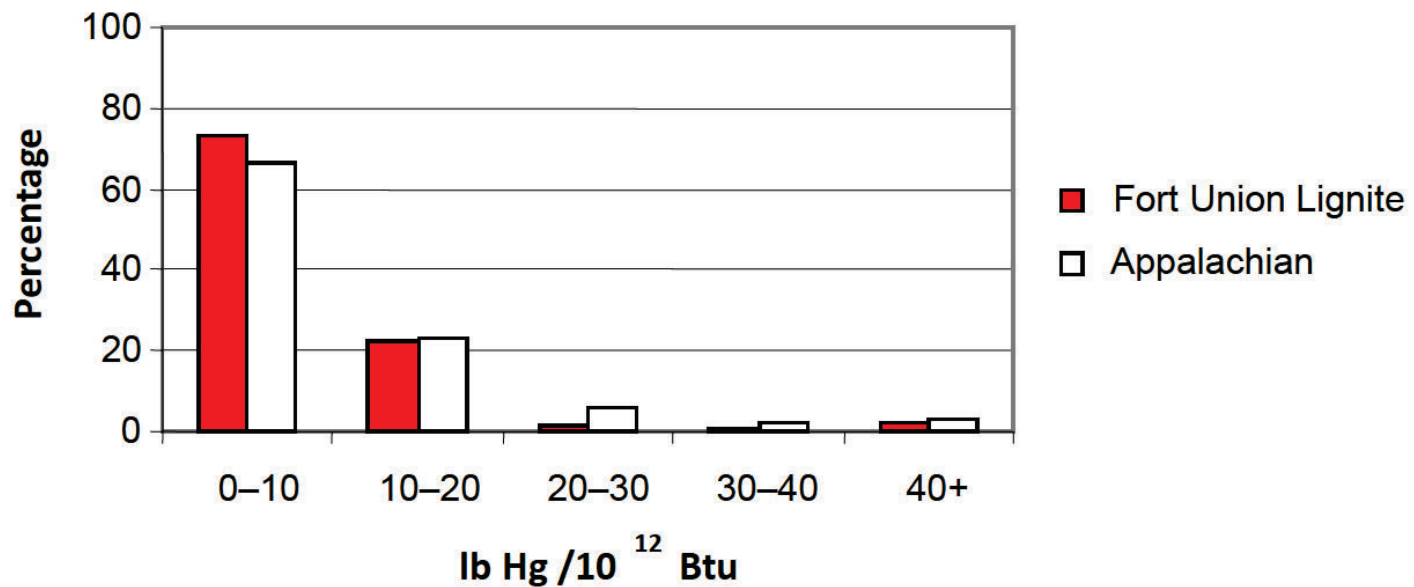
Fort Union Lignite Compared to Western Bituminous



Fort Union Lignite Compared to Eastern Interior Coals



Fort Union Lignite Compared to Appalachian Coals



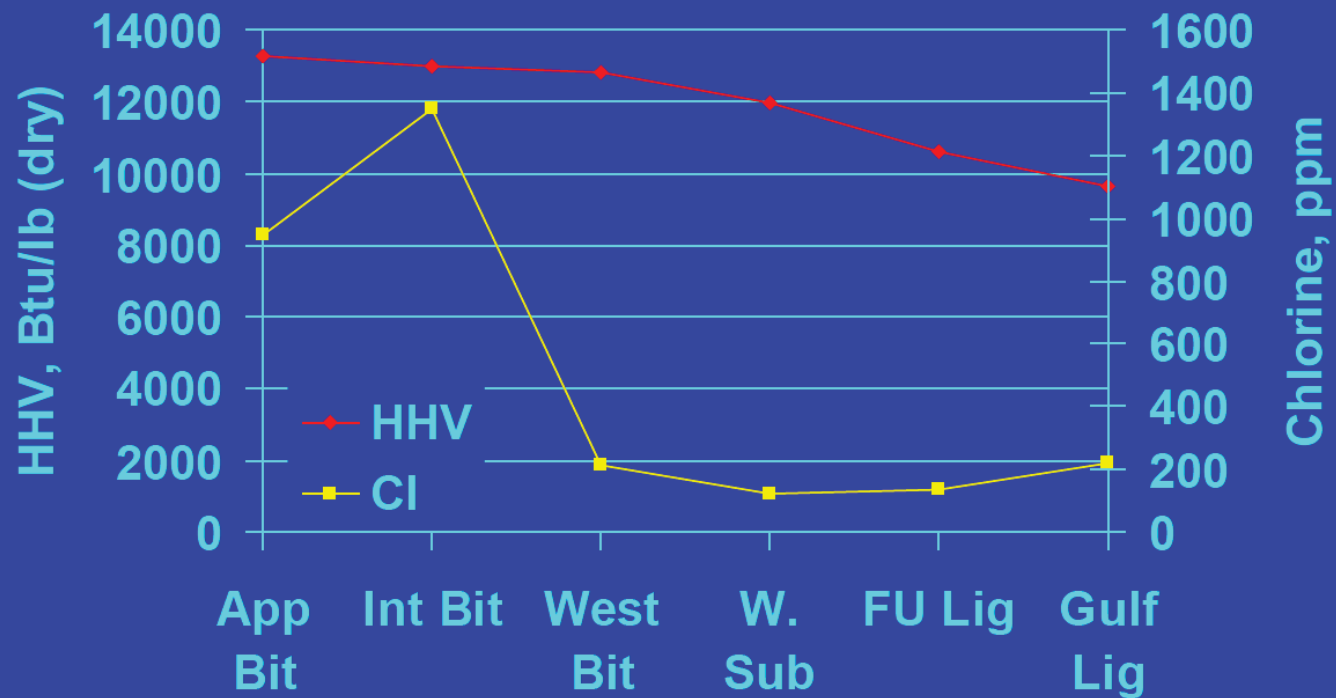
Background

Results of ICR Coal Analysis by Region

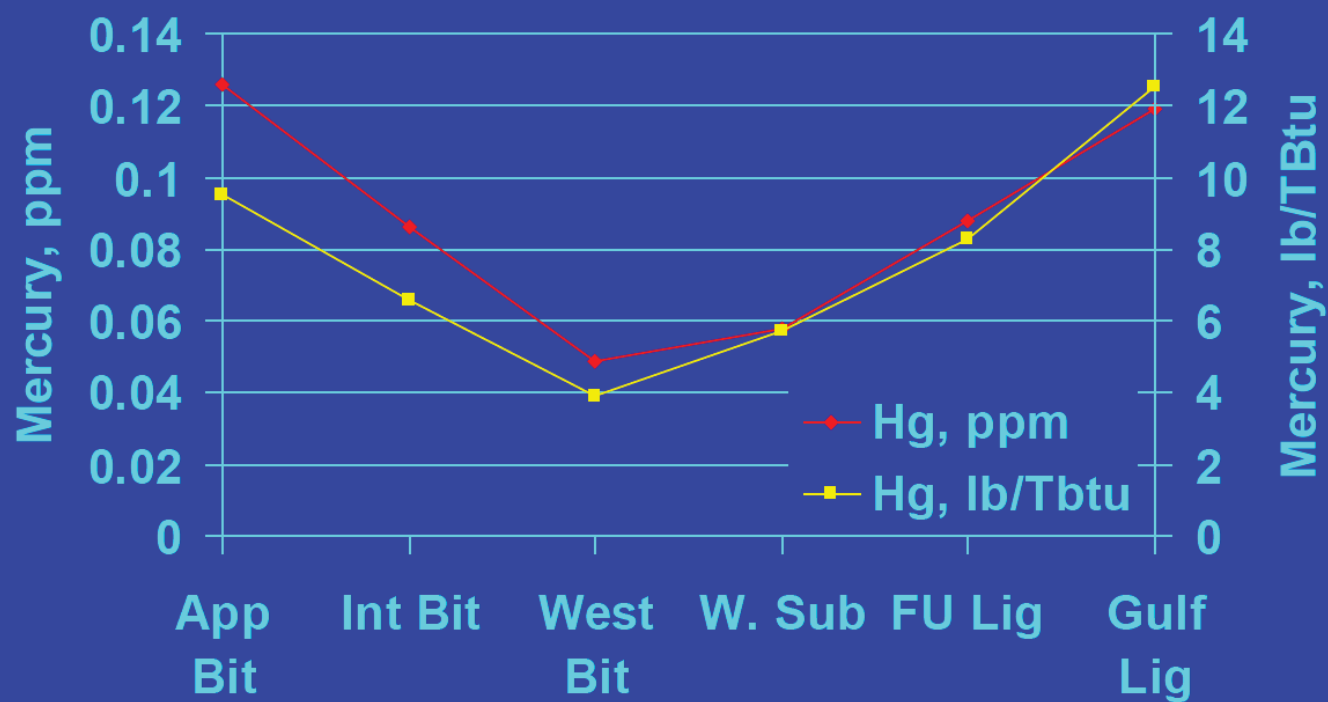
Dry basis

Region and Rank	No. of Samples	Hg, ppm	Cl, ppm	S, %	Ash, %	Btu/lb	Moisture, %	Hg, lb/TBtu
Appalachian Bituminous	19,530	0.126	948	1.67	11.65	13,275	2.5	9.5
Interior Bituminous	3763	0.086	1348	2.45	10.43	13,001	6.6	6.6
Western Bituminous	1471	0.049	215	0.57	10.51	12,614	4.2	3.9
Western Subbituminous	7989	0.068	124	0.48	7.92	11,971	19.4	5.7
Fort Union Lignite	424	0.088	139	1.15	13.37	10,585	37.3	8.3
Gulf Coast Lignite	623	0.119	221	1.39	23.56	9646	34.5	12.5

Comparison of Average Coal Characteristics



Comparison of Average Mercury Concentrations in Coal



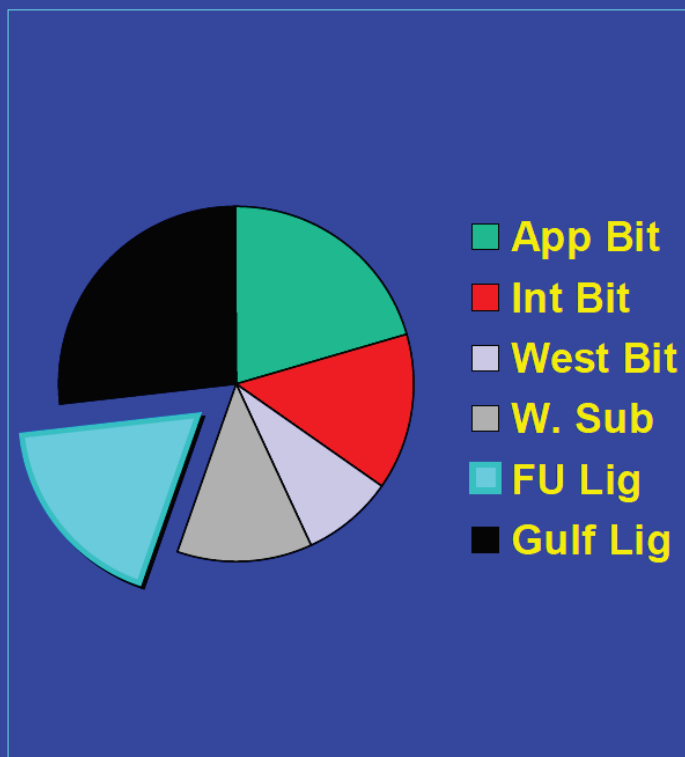
EERC
Energy & Environmental Research Center

Comparison of Mercury in Coal Based on Coal Consumption

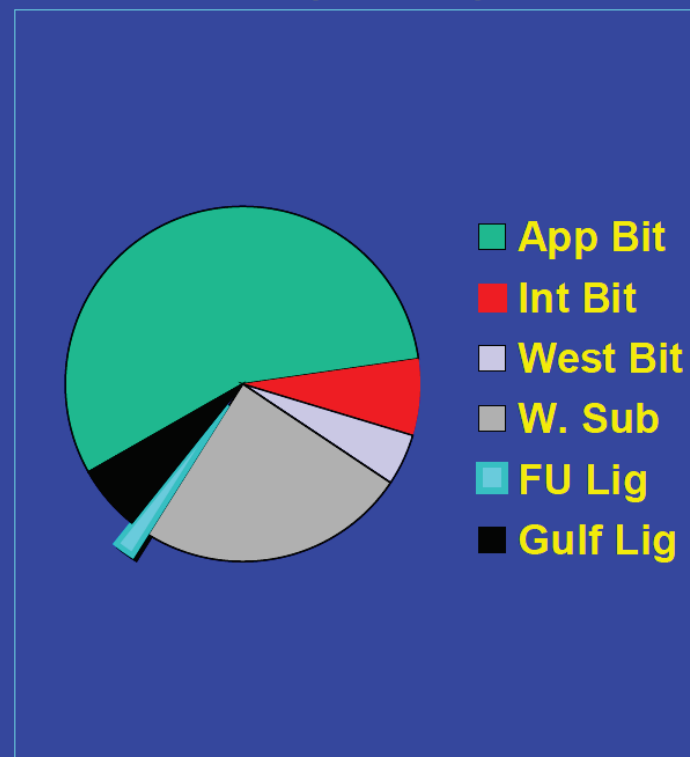
Region/rank	Mercury In Coal	Mercury in Coal	Coal Consumed	Coal Consumed	Mercury
	ppm, dry basis	Lb/TBtu	As received million tons/yr	Dry basis million tons/yr	In coal tons/yr
Appalachian (Eastern) bituminous	0.126	9.5	342	333	42.1
Interior bituminous	0.086	6.6	67	63	5.4
Western bituminous	0.049	3.9	75	72	3.5
Western subbituminous	0.068	5.7	336	271	18.4
Fort Union Lignite	0.088	8.3	23	14	1.3
Gulf Coast Lignite	0.119	12.5	57	37	4.5
Totals			900	790	75.2

Comparison of Mercury in Coal Based on Coal Consumed

Mercury, lb/TBtu



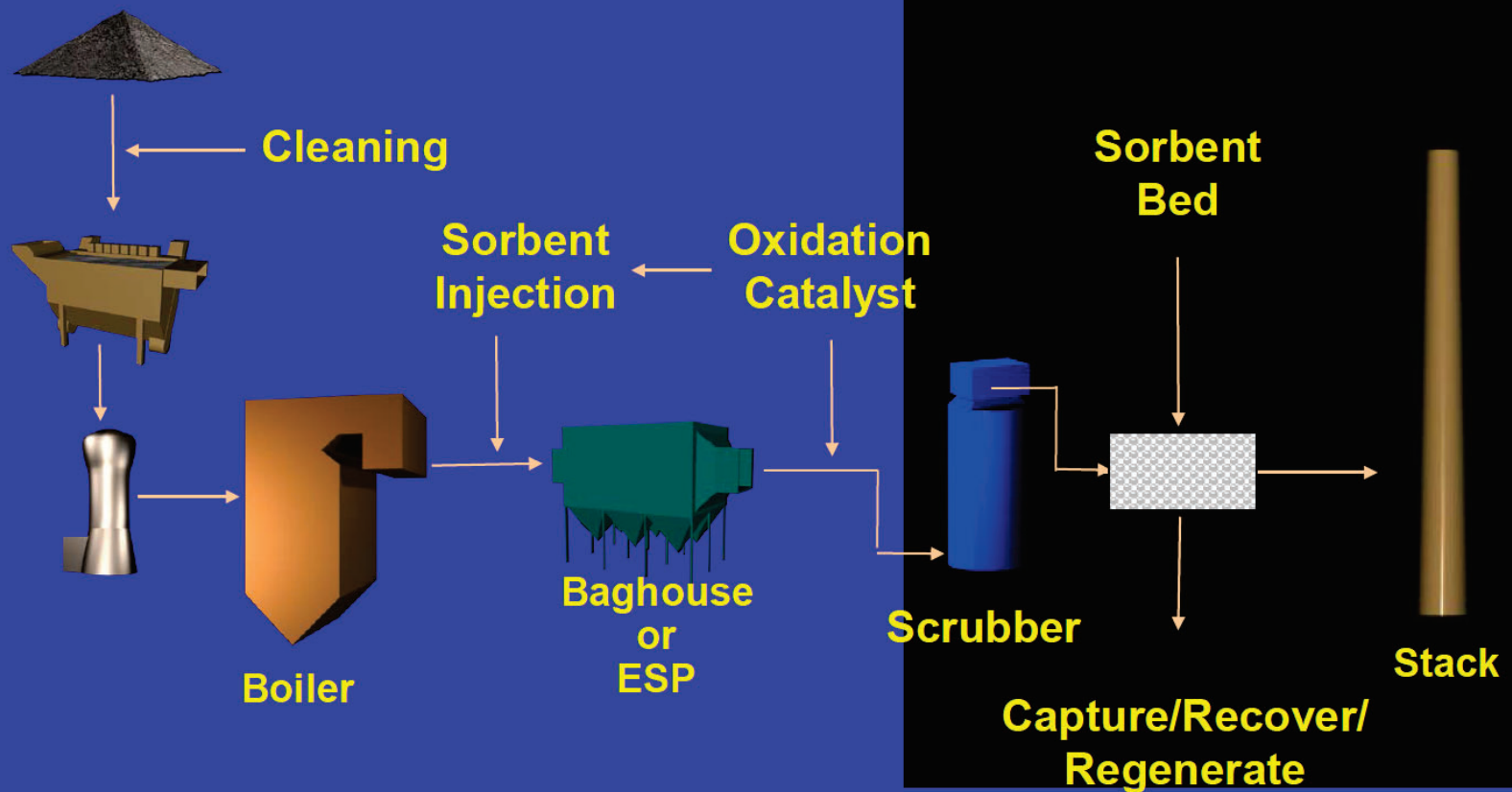
Mercury, ton/yr



Conclusions – Fort Union Lignite Perspective

Region and Rank	Ranking Lowest to Highest				
	Cl ppm	Hg lb/TBtu	Hg ppm	Coal Consumed tpy	Hg in Coal tpy
Appalachian Bituminous	5	5	6	6	6
Interior Bituminous	6	3	3	3	4
Western Bituminous	3	1	1	4	3
Western Subbituminous	1	2	2	5	5
Fort Union Lignite	2	4	4	1	1
Gulf Coast Lignite	4	6	5	2	2

Mercury Control Options



Power Plant Configurations

SaskPower

Plant Owner	Plant/ Unit	City	State	MWe	Boiler Type	NOx Control	SO2 Control		PM Control	
							Dry FGD	Wet FGD	Cold ESP	Fab Filter
Sask Power	Poplar River 1	Coronach	Sk	300	CE T-Fired	CCOFA			X	
Sask Power	Poplar River 2	Coronach	Sk	300	B&W Op Wall	LNB			X	
Sask Power	Shand	Estevan	Sk	300	B&W Op Wall	LNB	FSI & LIFAC		X	
Sask Power	Boundary Dam 1	Estevan	Sk	66	B&W Front Wall	OFA				
Sask Power	Boundary Dam 2	Estevan	Sk	66	CE T-Fired	OFA				
Sask Power	Boundary Dam 3	Estevan	Sk	150	CE T-Fired	OFA			X	
Sask Power	Boundary Dam 4	Estevan	Sk	150	CE T-Fired	OFA			X	
Sask Power	Boundary Dam 5	Estevan	Sk	150	CE T-Fired	OFA			X	
Sask Power	Boundary Dam 6	Estevan	Sk	292	CE T-Fired	OFA			X	

Page 27 of 49

Total SaskPower Capacity ~ 1774 MWe

Power Plant Configurations

North Dakota

Plant Owner	Plant/ Unit	City	State	MWe	Boiler Type	NOx Control	SO2 Control		PM Control	
							Dry FGD	Wet FGD	Cold ESP	Fab Filter
Basin	Leland Olds Unit 1	Stanton	ND	216	B&W Wall Fired	LNB OFA			X	
Basin	Leland Olds Unit 2	Stanton	ND	440	B&W Cyclone	None			X	
Basin	Antelope Valley 1	Beulah	ND	435	CE T-Fired	LNOVF	X			X
Basin	Antelope Valley 2	Beulah	ND	435	CE T-Fired	LNOVF	X			X
Great River	Coal Creek 1	Underwood	ND	540	CE T-Fired	LCN3		X	X	
Great River	Coal Creek 2	Underwood	ND	540	CE T-Fired	LCN3		X	X	
Great River	Stanton Station	Stanton	ND	140	B&W Wall Fired	LNB			X	
Great River	Stanton Station 10	Stanton	ND	60	CE T-Fired	LNB	X			X

Power Plant Configurations North Dakota (continued)

Plant Owner	Plant/ Unit	City	State	MWe	Boiler Type	NOx Control	SO2 Control		PM Control	
							Dry FGD	Wet FGD	Cold ESP	Fab Filter
MDU	Heskett Unit 1	Mandan	ND	25	Riley Stoker	None			X	
MDU	Heskett Unit 2	Mandan	ND	85	B&W Fluid Bed	None	FBC		X	
MDU	Lewis & Clark	Sidney	MT	60	CE T-Fired	LNB		X	X	
Minnkota	Milton Young 1	Center	ND	235	B&W Cyclone	None			X	
Minnkota	Milton Young 2	Center	ND	440	B&W Cyclone	None		X	X	
OtterTail	Coyote	Beulah	ND	460	B&W Cyclone	None	X			X
OtterTail	Bigstone	Big Stone	SD	500	B&W Cyclone	None			X	

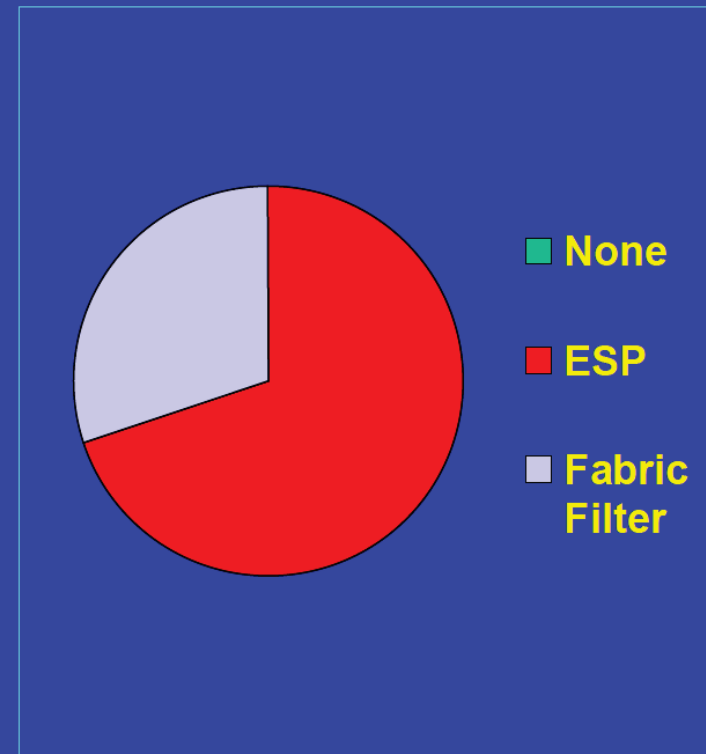
Total ND Capacity ~ 4611 MWe

Power Plant Configuration Comparison of PM Controls

SaskPower



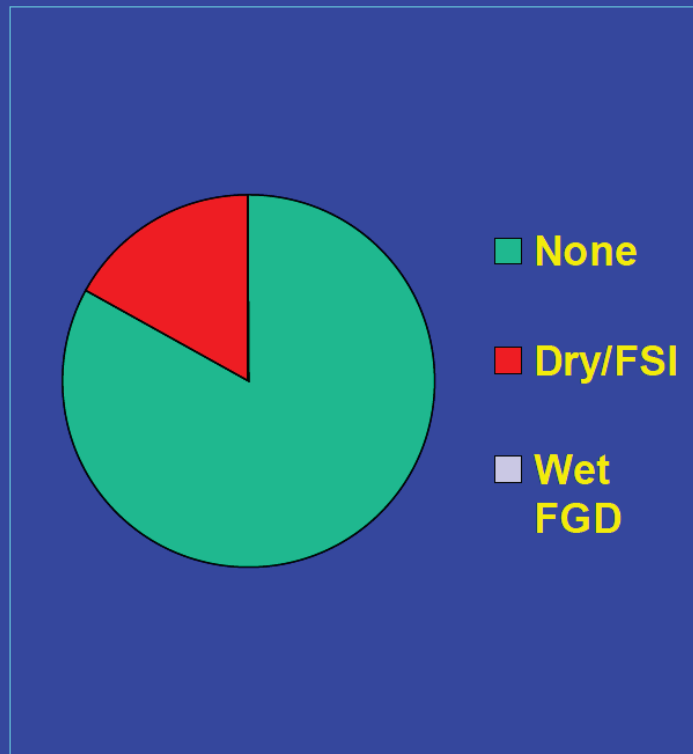
ND Utilities



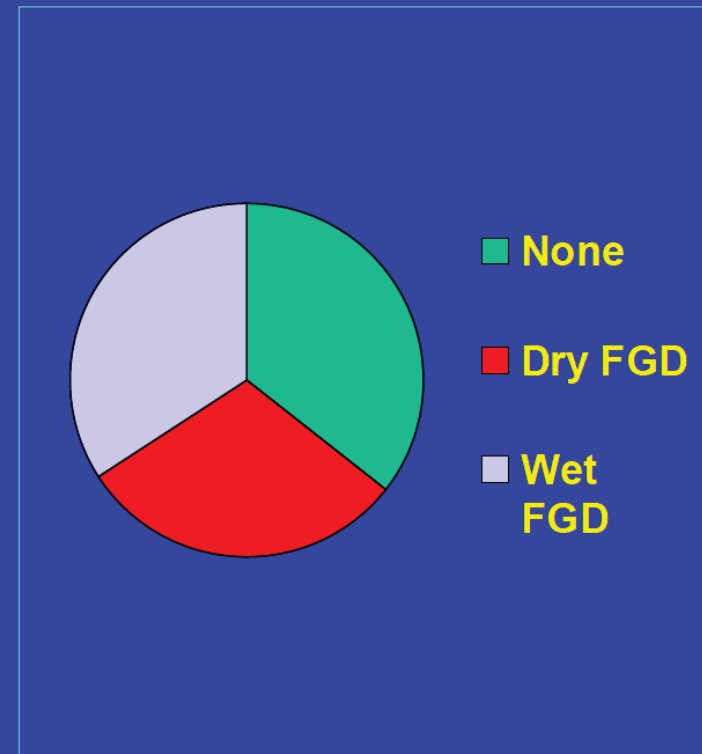
Based on MW Capacity

Power Plant Configuration Comparison of SO₂ Controls

SaskPower



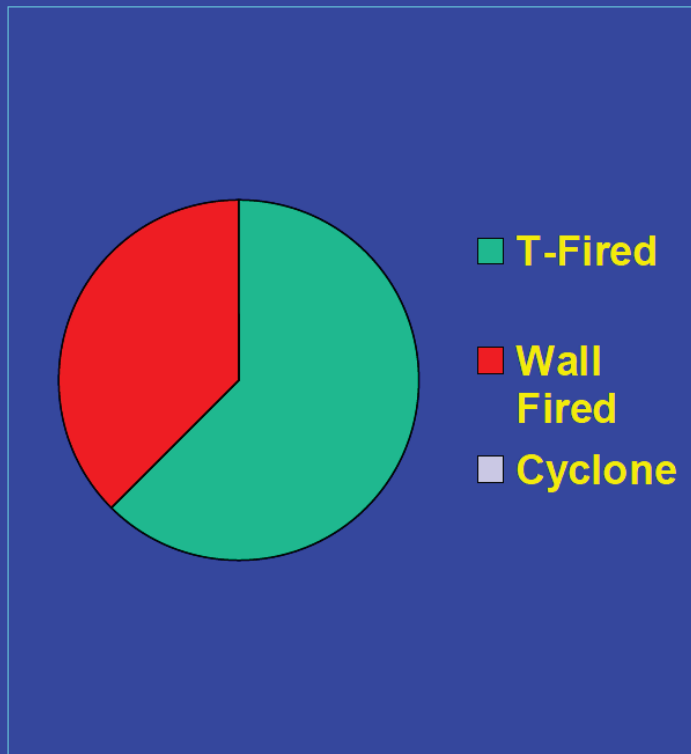
ND Utilities



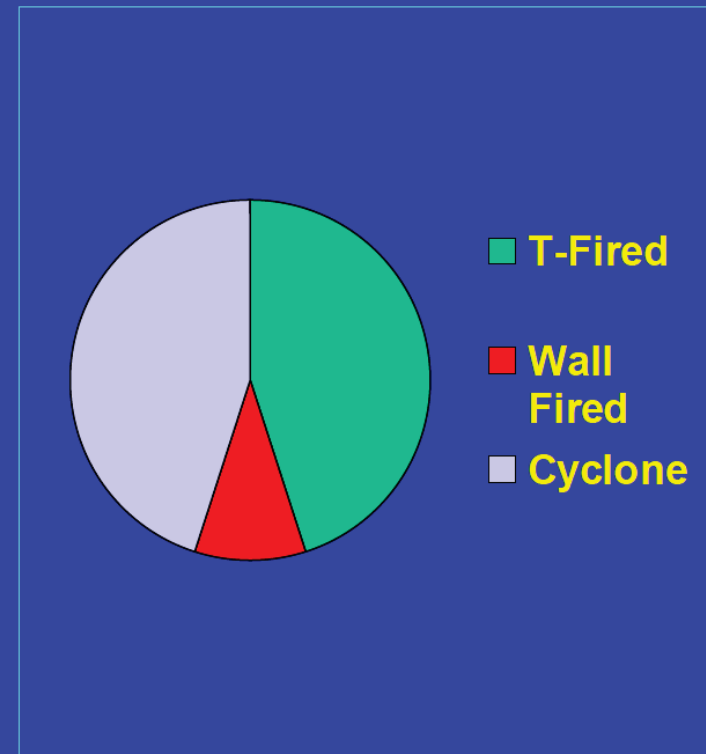
Based on MW Capacity

Power Plant Configuration Comparison of Firing Method

SaskPower



ND Utilities



Based on MW Capacity

Comparison of Mercury Emissions and Speciation - SaskPower

Preliminary

Plant Name	Gas Temp	Hg in coal	Avg Hg Emitted	Total Mercury Reduced, %				Mercury Outlet, lb/Tbtu				Mercury Inlet, lb/Tbtu			
				HgTot	Hg	Hg++	HgP	HgTot	Hg	Hg++	HgP	HgTot	Hg	Hg++	HgP
Poplar River 1	302	292	136	53.3				4.67	3.88	0.79	0.00	10.00			
Poplar River 2	302	298	139	53.3				4.67	3.88	0.79	0.00	10.00			
Shand Station	302	192	123	35.7				4.66	3.94	0.48	0.24	7.25			
Boundary Dam 1	365	41	21	48.3				3.23	2.75	0.32	0.16	6.25			
Boundary Dam 2	365	42	21	48.3				3.23	2.75	0.32	0.16	6.25			
Boundary Dam 3	365	79	41	48.3				3.23	2.75	0.32	0.16	6.25			
Boundary Dam 4	365	80	41	48.3				3.23	2.75	0.32	0.16	6.25			
Boundary Dam 5	365	77	40	48.3				3.23	2.75	0.32	0.16	6.25			
Boundary Dam 6	365	148	77	48.3				3.23	2.75	0.32	0.16	6.25			
SaskPower Sum	344	1,249	640	48.0				3.71	3.13	0.44	0.13	7.20			
ICR Data	xxxxxxxx														
Estimate	xxxxxxxx														

Comparison of Mercury Emissions and Speciation - ND Utilities

Preliminary

Plant Name	City	State	MWe	Cap Factor	Gas Temp	Hg in coal	Avg Hg Emitted	Total Mercury Reduced, %				Mercury Outlet, lb/Tbtu				Mercury Inlet, lb/Tbtu			
					F	lb/yr	lb/yr	HgTot	Hg	Hg++	HgP	HgTot	Hg	Hg++	HgP	HgTot	Hg	Hg++	HgP
Leland Olds 1	Stanton	ND	216	0.69	395	108	81	24.8	19.0	-93.3	100.0	3.40	2.82	0.58	0.00	4.52	3.48	0.30	0.74
Leland Olds 2	Stanton	ND	440	0.69	395	212	159	24.8	19.0	-93.3	100.0	3.40	2.82	0.58	0.00	4.52	3.48	0.30	0.74
Antelope Valley 1	Beulah	ND	435	0.69	307	249	218	12.5	12.3	-23.1	85.7	3.01	2.84	0.16	0.01	3.44	3.24	0.13	0.07
Antelope Valley 2	Beulah	ND	435	0.69	307	249	218	12.5	12.3	-23.1	85.7	3.01	2.84	0.16	0.01	3.44	3.24	0.13	0.07
Coal Creek Unit 1	Underwood	ND	540	0.65	320	336	311	7.3	25.8	-198.7	100.0	8.88	6.52	2.36	0.00	9.58	8.79	0.79	0.00
Coal Creek Unit 2	Underwood	ND	540	0.70	320	362	336	7.3	25.8	-198.7	100.0	8.88	6.52	2.36	0.00	9.58	8.79	0.79	0.00
Stanton Station 1	Stanton	ND	140	0.69	309	90	90	-2.6	-0.5	-300.0	80.0	6.63	6.38	0.24	0.01	6.46	6.35	0.06	0.05
Stanton Station 10	Stanton	ND	60	0.69	353	32	27	14.8	10.6	63.0	95.0	6.27	6.16	0.10	0.01	7.36	6.89	0.27	0.20
Heskett Unit 1	Mandan	ND	25	0.61	325	16	15	7.2	1.6	13.3	95.2	6.21	4.90	1.30	0.01	6.69	4.98	1.50	0.21
Heskett Unit 2	Mandan	ND	85	0.61	325	39	21	46.6	-55.6	70.7	98.4	3.57	3.08	0.44	0.05	6.69	1.98	1.50	3.21
Lewis & Clark	Sidney	MT	60	0.61	389	26	14	43.8	-27.6	96.8	99.0	9.12	8.84	0.27	0.01	16.23	6.93	8.31	0.99
M.R. Young 1	Center	ND	235	0.69		161	161	-2.2	0.7	-137.7	100.0	9.64	8.38	1.26	0.00	9.43	8.44	0.53	0.46
M. R. Young 2	Center	ND	439	0.69		303	303	-2.2	0.7	-137.7	100.0	9.64	8.38	1.26	0.00	9.43	8.44	0.53	0.46
Coyote Unit 1	Beulah	ND	460	0.68	341	388	304	21.7	3.2	91.0	94.6	10.93	10.70	0.18	0.05	13.96	11.05	1.99	0.92
Bigstone	Big Stone	SD	500	0.68	341	346	140	59.4	0.0	8.9	99.8	4.21	0.70	3.50	0.01	10.38	0.70	3.84	5.84
ND Summary			314	0.67	336	2,917	2,399	17.9	2.0	-54.9	95.2	6.67	5.65	1.01	0.01	8.37	5.95	1.48	0.94
Page 34 of 49																			
ICR Data - xxxx																			
Estimate - xxxx																			

Comparison of Mercury Emissions and Speciation - ND Utilities

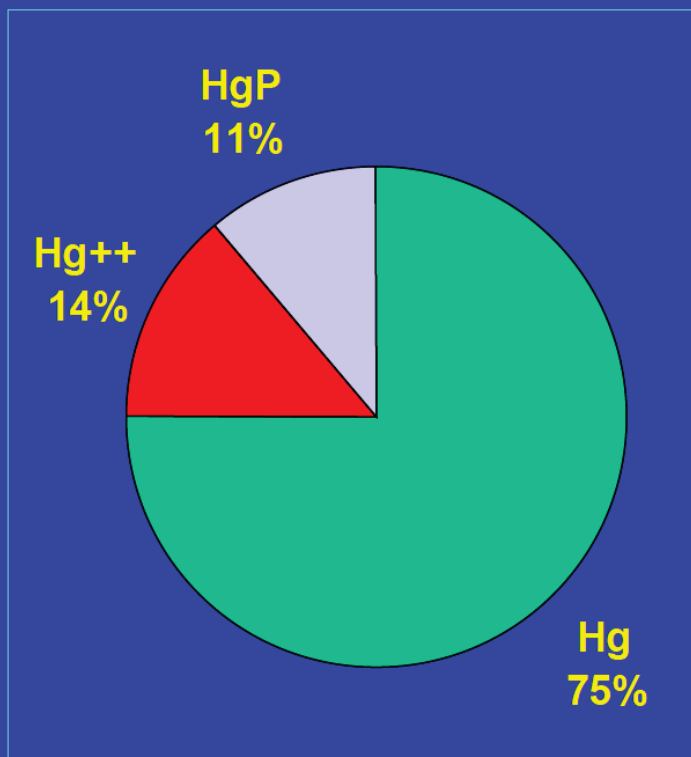
Preliminary

Plant Name	MWe	Average Mercury Concent.	Max Mercury Concent. 95%	Min Mercury Concent. 95%	Hg in coal	Avg Hg Emitted	Hg Tot Red %	Hg Out	Hg Calc in Coal	Hg Inlet
		ppm dry	ppm dry	ppm dry	lb/yr	lb/yr	HgTot	HgTot	HgTot	HgTot
Leland Olds 1	216	0.073	0.103	0.050	108	81	24.8	3.40	6.83	4.52
Leland Olds 2	440	0.073	0.103	0.050	212	159	24.8	3.40	6.83	4.52
Antelope Valley 1	435	0.069	0.109	0.050	249	218	12.5	3.01	6.56	3.44
Antelope Valley 2	435	0.069	0.109	0.050	249	218	12.5	3.01	6.56	3.44
Coal Creek Unit 1	540	0.098	0.135	0.051	336	311	7.3	8.88	9.87	9.58
Coal Creek Unit 2	540	0.098	0.135	0.051	362	336	7.3	8.88	9.87	9.58
Stanton Station 1	140	0.088	0.120	0.051	90	90	-2.6	6.63	8.29	6.46
Stanton Station 10	60	0.088	0.120	0.051	32	27	14.8	6.27	8.29	7.36
Heskett Unit 1	25	0.088	0.143	0.042	16	15	7.2	6.21	7.97	6.69
Heskett Unit 2	85	0.088	0.143	0.042	39	21	46.6	3.57	7.97	6.69
Lewis & Clark	60	0.088	0.143	0.042	26	14	43.8	9.12	7.97	16.23
M.R. Young 1	235	0.113	0.153	0.082	161	161	-2.2	9.64	10.67	9.43
M. R. Young 2	439	0.113	0.153	0.082	303	303	-2.2	9.64	10.67	9.43
Coyote Unit 1	460	0.135	0.230	0.084	388	304	21.7	10.93	12.43	13.96
Bigstone	500	0.126			346	140	59.4	4.21	10.35	10.38
ND Summary	314	0.095	0.138	0.056	2,917	2,399	17.9	6.67	8.88	8.37
ICR Data - xxxx										
Estimate - xxxx										

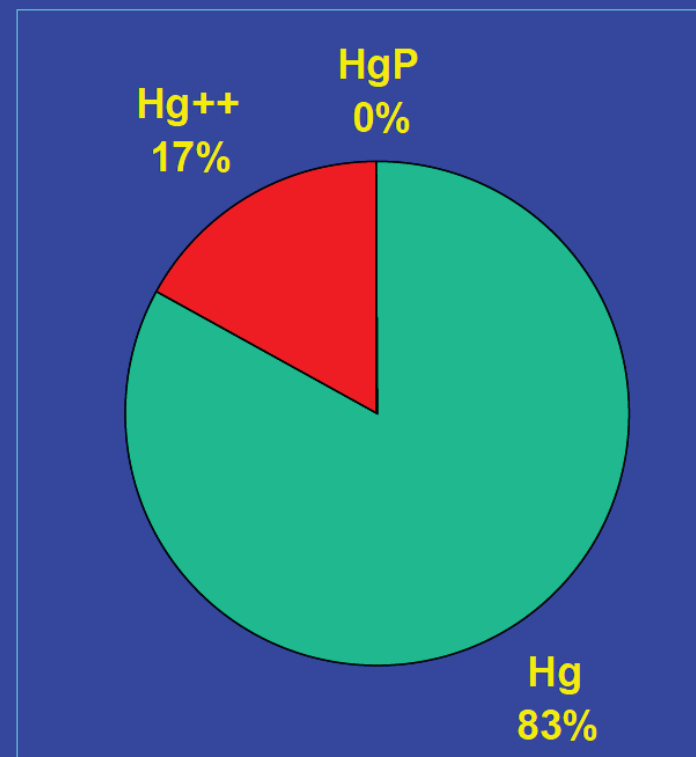
Page 35 of 49

Comparison of Mercury Emissions and Speciation

Inlet, Avg 8.3 lb/TBtu



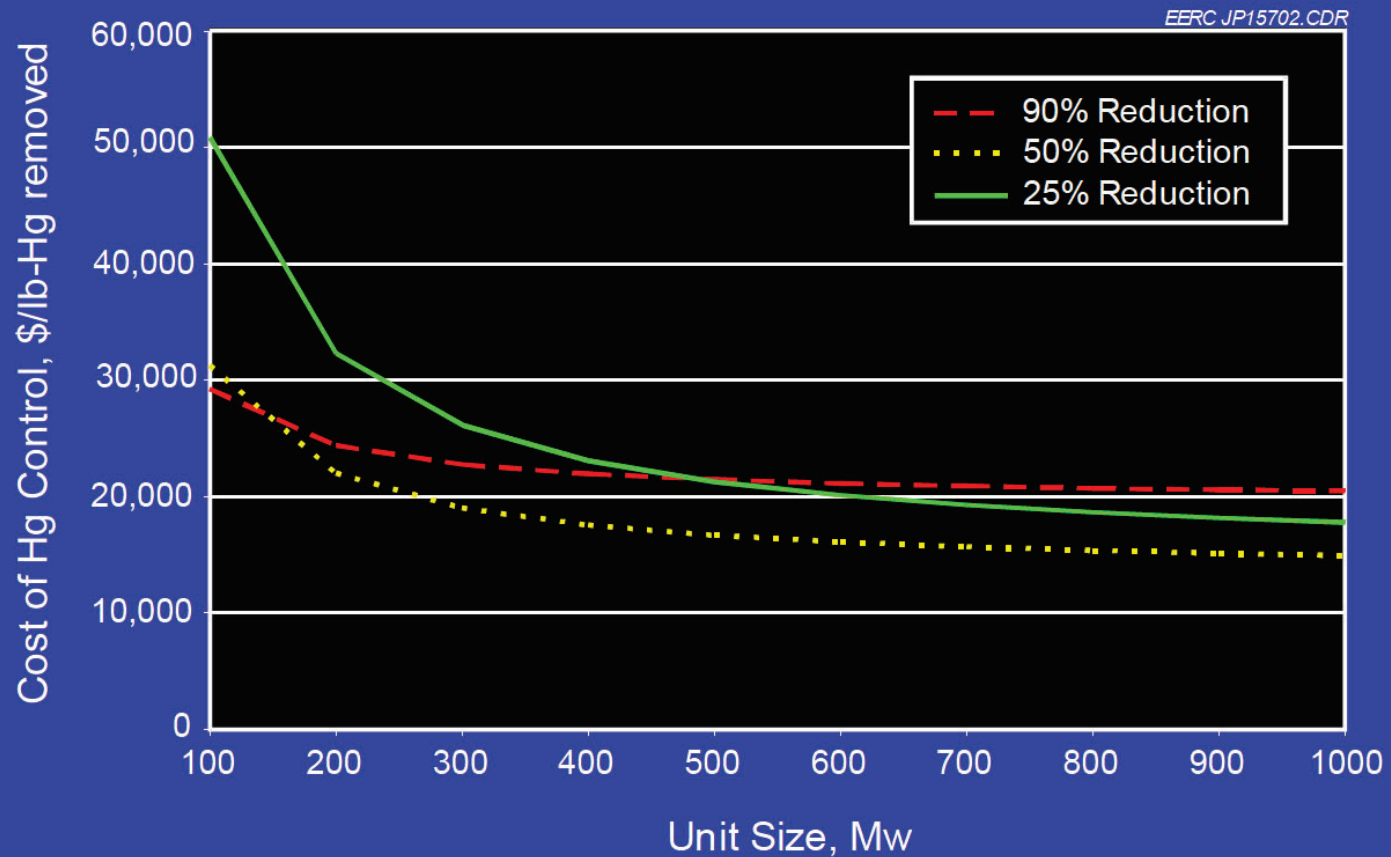
Stack, Avg 6.4 lb/TBtu



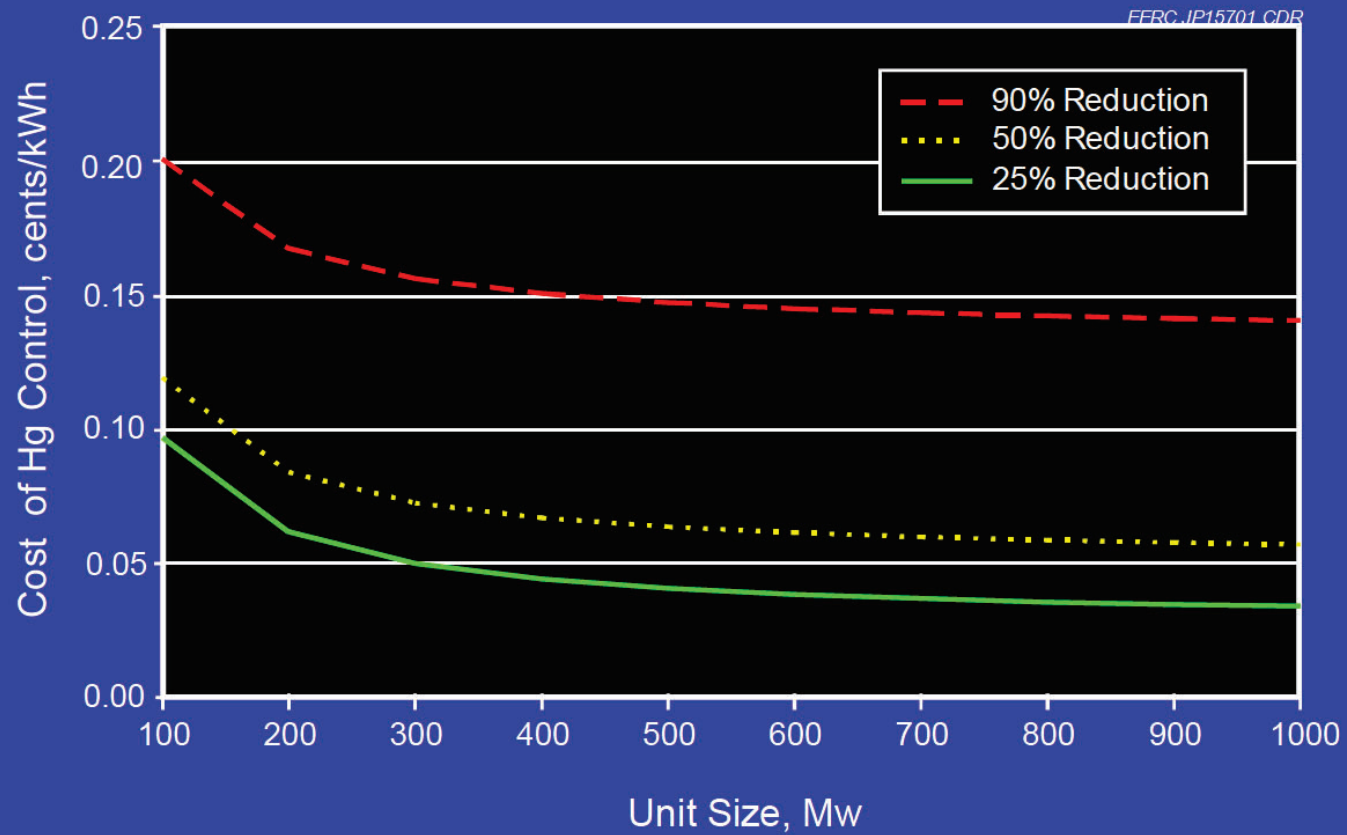
Focus on Sorbent-Based Technology

- All ND and most SaskPower plants are equipped with particulate control devices
- Sorbent injection may be easily added to these plants at relatively low cost as compared to other mercury control options
- Preliminary bench- and pilot-scale tests indicate that carbon-based sorbents may be effective for mercury capture under certain conditions. More data needed under different conditions
- Approximately 80-85% of the mercury is in the elemental form which can not be captured in scrubbers
- For units equipped with scrubbers, catalytic oxidation may be an option. Some sorbents have the potential to facilitate oxidation.

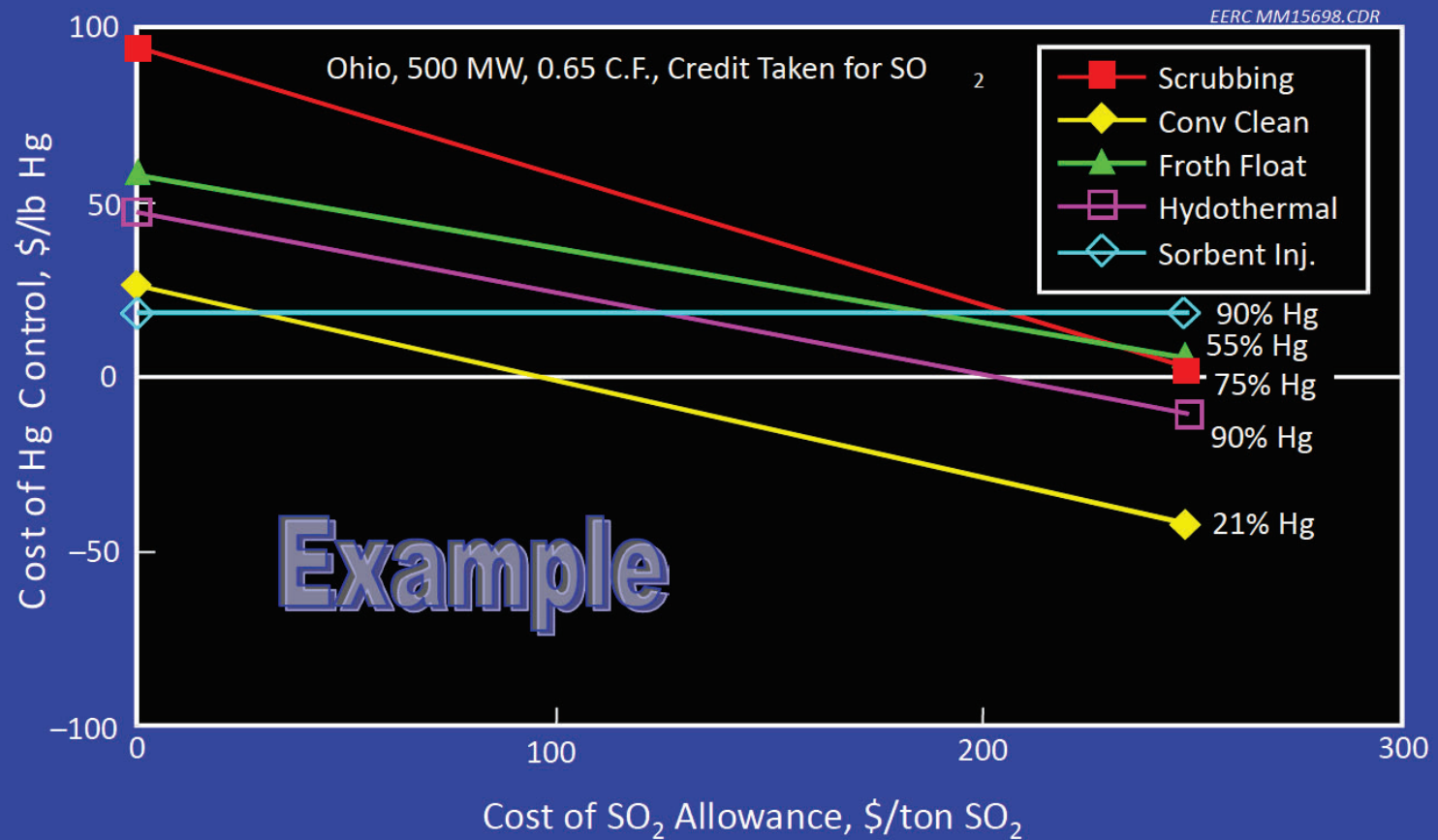
Cost of Mercury Control Sorbent Injection



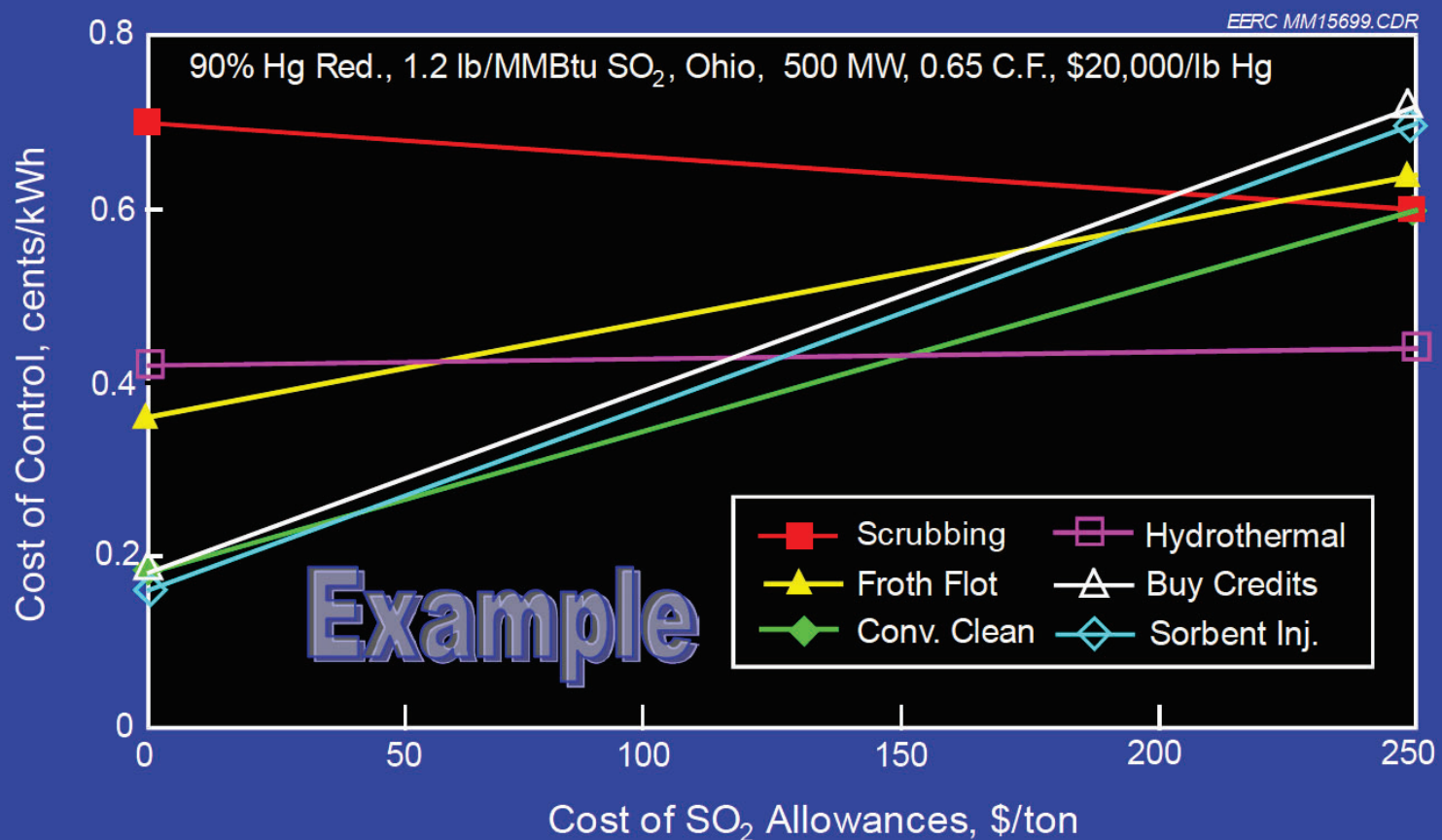
Cost of Mercury Control Sorbent Injection



Comparison of Mercury Control Costs for Selected Technologies



Cost of Meeting 1.2 lb/MM Btu SO₂ and 90% Mercury Reduction for Selected Technologies



Project Goals

Develop, Test, and Demonstrate Sorbent-Based Technologies for Utilities Burning Lignite Coal

- Increase the scientific understanding of mercury / flue gas interactions leading to more effective design of sorbents
- Test a range of sorbent-based technology options
- Determine and demonstrate optimum conditions and sorbents for Hg capture in pilot facility
- Field demonstrate sorbent-based technology to prove and quantify effectiveness, performance, and cost

Approach

Building on Previous Efforts

Phase I Bench/Pilot-Scale Testing

- Flue Gas Characterizations
- Bench Scale Screening
- Fixed Bed and Entrained Flow Evaluations
- Pilot-Scale Testing
- Byproduct Analyses

Phase II Full-Scale Testing/Demonstration

- Field Demonstration
 - Select sorbent and system configuration
 - Prepare site and install technology hardware
 - Evaluate sorbent impacts
 - Evaluate impact of operation variables
 - Byproduct analyses
 - Quantify effectiveness and cost

Phase II, Field Demonstration

Proposed Site – Poplar River Power Station (SaskPower)

- Two Units, Commissioned in 1981 and 1983
- Unit 1 = 298 MW & Unit 2 = 294 MW
- Electrostatic Precipitators for particulate control



Poplar River Power Station

- South-central Saskatchewan
- 10 km SE of Coronach

Page 44 of 49

Phase II

Poplar River Power Station

Poplar Station

Plant/ Unit	MW	Cap Fact	Boiler Type	NOx Cont	PM Cont	Boiler Input,	Gas Temp	Hg in Coal,	Hg Emit	Hg Red.
						MBtu/h	F	lbs/yr	lb/yr	%
Poplar River 1	300	0.85	CE T-Fired	CCOFA	Cold ESP	4,200	302	360	138	55
Poplar River 2	300	0.78	B&W Op Wall	LNB	Cold ESP	4,200	302	360	138	55

Poplar Station Coal, dry basis

Preliminary

Moisture	Ash	Sulfur	HHV	Mercury	Coal Burned
%	%	%	Btu/lb	ppm	Tpy (dry)
37.8	21.0	0.85	9000	0.09	3,300,000



EERC
Energy & Environmental Research Center

Phase II Testing

Field Demonstration

- Define control technology, based on Phase I
 - Select most promising sorbent
 - Identify the process requirements
 - Sorbent injection upstream of a polishing filter, or
 - Highly reactive sorbent upstream of the ESP
 - Possible flue gas conditioning
- Perform demonstration on about ¼ of the flue gas from one unit
- Evaluate effectiveness as a function of process variables (Temperatures, sorbent size, sorbent characteristics, particulate control system operation, etc)
- Quantify performance, effectiveness, and cost

Funding Scenario

Phase	Phase Description	Cost
1	Development and Testing of Sorbents at EERC Bench-Pilot-Scale Facilities	\$830,000
2	Demonstration of Sorbent Technology at Saskatchewan Power Plant	\$1,500,000 -to- \$5,000,000

Phase I:

- ~\$400K from Industry: Saskatchewan Power, ND utilities, EPRI, and NDIC
- ~\$430K from Environment Canada and the U.S. DOE

Phase II:

- ~\$2 to 4 million from Saskatchewan Power and Environment Canada
- ~\$100K from ND utilities and EPRI
- ~\$200K from NDIC
- ~\$350K from the U.S. DOE

Project Management Plan

Mercury Control Technologies for Electric Utilities Burning Lignite Coals

SaskPower, Environment Canada, Luscar Ltd.,
Basin Electric, Excel Energy, GRE, Minnkota, Minnesota Power, Ottertail, EPRI
North Dakota Industrial Commission, U.S. Department of Energy

Ontario Ministry of the Environment

EERC

John Pavlish, Project Manager

Steve Benson
Sorbent Characterization

Mike Holmes
Pilot and Field Testing

Role of Sponsors

- Multi-sponsor project
- All sponsors participate in meetings, phone calls, etc
- All sponsors have access to data, reports, etc
- Project representative will work as team to develop project direction and plans (final decisions will be consensus and should consider equitable contribution)