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JUL 31 2006

STATE OF ILLINOIS
Pollution Control Board

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:)
)
PROPOSED NEW 35 ILL. ADM. CODE 225)
CONTROL OF EMISSIONS FROM)
LARGE COMBUSTION SOURCES (MERCURY))

R06-25
(Rulemaking – Air)

PC#6277

NOTICE

TO: Dorothy Gunn
Clerk
Illinois Pollution Control Board
James R. Thompson Center
100 West Randolph St., Suite 11-500
Chicago, IL 60601-3218

SEE ATTACHED SERVICE LIST

PLEAST TAKE NOTICE that I have today filed with the Office of the Clerk of the Illinois Pollution control Board the POST-HEARING COMMENTS OF THE ILLINOIS ENVIRONMENTAL PROTECTION AGENCY a copy of which is herewith served upon you

ILLINOIS ENVIRONMENTAL
PROTECTION AGENCY

By: ______________________
John J. Kim
Managing Attorney
Air Regulatory Unit
Division of Legal Counsel

DATED: July 28, 2006

Illinois Environmental Protection Agency
1021 North Grand Avenue East
P.O. Box 19276
Springfield, Illinois 62794-927

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POST-HEARING COMMENTS OF THE ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

NOW COMES the ILLINOIS ENVIRONMENTAL PROTECTION AGENCY (Illinois EPA), by one of its attorneys, John. J. Kim, and hereby submits comments in the above rulemaking proceeding. The Illinois EPA appreciates the efforts of the Illinois Pollution Control Board (Board) in this rulemaking regarding the request to add 35 Ill. Adm. Code Part 225 to control mercury emissions from coal-fired electric generating unties. Though the Illinois EPA responded to most every issue raised at the first hearing in this matter on the record during those proceedings, some outstanding issues remain to be addressed in these post-hearing comments.

RESPONSES TO QUESTIONS RAISED DURING THE JUNE 12, 2006 HEARING

Question: *Directed to James E. Staudt, Ph.D., CFA question 59 a,b,c from Ameren: With reference to page 156 of the technical support document,*

a. by unit, what are the coal types (bituminous, sub-bituminous) you are assuming IL units will be burning in 2009?
b. by unit, what are the 2009/10 control configuration (SO2, NOx and PM controls) you are assuming?
c. What is the level of co-benefits are you assuming for the 2009/10 control configurations (in pounds) and the removal efficiencies of these control configurations?

Answer: *Response from James E. Staudt, Ph.D., CFA:*

In response to questions 59 a, b, c, I stated at the hearing that I would provide a table that includes my assumptions from the TSD. Since preparing the TSD, my understanding of the configuration of some of the plants has changed. Therefore I am presenting two tables – one that shows what was assumed in the original TSD and the other is based upon my more current understanding. In the more recent one I show the calculated cobenefit in ounces as well as percentage. For the few unscrubbed bituminous units (except for Meredosia), I assumed that 90% removal or 0.008 lb/GWhr was achievable through a combination of cobenefit (around 30-50%) and sorbent injection (additional 85% removal). I assumed no cobenefit mercury removal for any of the PRB fired units, except Baldwin. It is likely that some significant cobenefit removals are achieved at some of these units. This will have the effect of lowering the cost or increasing the amount of mercury removed from the estimates shown here.

Characteristics used for original TSD

Owner	Plant Name	Unit #	Coal	Post-Comb NOx	FGD	PM	Co-benefit %	Comments
Ameren	DUCK CREEK	1	BIT	SCR	Wet FGD	Cold-side ESP	90% or 0.008	
Ameren	NEWTON	1	SUB	None	None	Cold-side ESP	0	
Ameren	NEWTON	2	SUB	None	None	Cold-side ESP	0	
Ameren	E D EDWARDS	1	SUB	None	None	Cold-side ESP	0	
Ameren	E D EDWARDS	2	SUB	None	None	Cold-side ESP	0	
Ameren	E D EDWARDS	3	BIT	SCR	None	Cold-side ESP	30%	
Ameren	COFFEEN	01	BIT	SCR	None	Cold-side ESP	30%	
Ameren	COFFEEN	02	SUB	SCR	None	Cold-side ESP	30%	
Ameren	HUTSONVILLE	05	BIT	None	None	Cold-side ESP	30%	
Ameren	HUTSONVILLE	06	BIT	None	None	Cold-side ESP	30%	
Ameren	MEREDOSIA	01	SUB	None	None	Cold-side ESP	0	
Ameren	MEREDOSIA	02	BIT	None	None	Cold-side ESP	30%	
Ameren	MEREDOSIA	03	SUB	None	None	Cold-side ESP	0	
Ameren	MEREDOSIA	04	SUB	None	None	Cold-side ESP	0	
Ameren	MEREDOSIA	05	SUB	None	None	Cold-side ESP	0	
CWLP	DALLMAN	31	BIT	SCR	Wet FGD	Cold-side ESP	90% or 0.008	
CWLP	DALLMAN	32	BIT	SCR	Wet FGD	Cold-side ESP	90% or 0.008	
CWLP	DALLMAN	33	BIT	SCR	Wet FGD	Cold-side ESP	90% or 0.008	
Dynegy	BALDWIN	1	SUB	SCR	None	Cold-side ESP	80%	To add FF, which reduces sorbent injection rate. Cobenefit based on Dynegy presentation to IL EPA
Dynegy	BALDWIN	2	SUB	SCR	None	Cold-side ESP	80%	
Dynegy	BALDWIN	3	SUB	None	None	Cold-side ESP	80%	
Dynegy	HAVANA	9	SUB	SCR	None	Hot-side ESP	0	To add FF, TOXECON assumed
Dynegy	HENNEPIN	1	SUB	None	None	Cold-side ESP	0	
Dynegy	HENNEPIN	2	SUB	None	None	Cold-side ESP	0	
Dynegy	VERMILION	1	BIT	None	None	Cold-side ESP	0	To add FF, TOXECON assumed
Dynegy	VERMILION	2	BIT	None	None	Cold-side ESP	0	
Dynegy	WOOD RIVER	4	SUB	None	None	Cold-side ESP	0	
Dynegy	WOOD RIVER	5	SUB	None	None	Cold-side ESP	0	
Joppa	JOPPA STEAM	1	SUB	None	None	Cold-side ESP	0	
Joppa	JOPPA STEAM	2	SUB	None	None	Cold-side ESP	0	

Joppa	JOPPA STEAM	3	SUB	None	None	Cold-side ESP	0	
Joppa	JOPPA STEAM	4	SUB	None	None	Cold-side ESP	0	
Joppa	JOPPA STEAM	5	SUB	None	None	Cold-side ESP	0	
Joppa	JOPPA STEAM	6	SUB	None	None	Cold-side ESP	0	
Kincaid	KINCAID	1	SUB	SCR	None	Cold	0	
Kincaid	KINCAID	2	SUB	SCR	None	Cold	0	
Marion	MARION	4	BIT	SCR	Wet FGD	Cold	90% or 0.008	
Marion	MARION	123	BIT	CFB-SNCR	None	Fabric Filter	90% or 0.008	
Midwest	JOLIET 29	71	SUB	None	None	Cold-side ESP	0	
Midwest	JOLIET 29	72	SUB	None	None	Cold-side ESP	0	
Midwest	JOLIET 29	81	SUB	None	None	Cold-side ESP	0	
Midwest	JOLIET 29	82	SUB	None	None	Cold-side ESP	0	
Midwest	JOLIET 9	5	SUB	None	None	Cold-side ESP	0	
Midwest	CRAWFORD	7	SUB	None	None	Cold-side ESP	0	
1Midwest	CRAWFORD	8	SUB	None	None	Cold-side ESP	0	
Midwest	POWERTON	51	SUB	None	None	Cold-side ESP	0	
Midwest	POWERTON	52	SUB	None	None	Cold-side ESP	0	
Midwest	POWERTON	61	SUB	None	None	Cold-side ESP	0	
Midwest	POWERTON	62	SUB	None	None	Cold-side ESP	0	
Midwest	WAUKEGAN	17	SUB	None	None	Cold-side ESP	0	
Midwest	WAUKEGAN	7	SUB	None	None	Hot-side ESP	0	TOXECON assumed
Midwest	WAUKEGAN	8	SUB	None	None	Cold-side ESP	0	
Midwest	WILL COUNTY	1	SUB	None	None	Cold-side ESP	0	
6455Midwest	WILL COUNTY	2	SUB	None	Cold-side ESP		0	
Midwest	WILL COUNTY	3	SUB	None	None	Hot-side ESP	0	TOXECON assumed
Midwest	WILL COUNTY	4	SUB	None	None	Cold-side ESP	0	
Midwest	FISK	19	SUB	None	None	Cold-side ESP	0	

Inputs to revised cost estimate

Owner	Plant Name	Unit #	Coal	Post-Comb NOx	FGD	PM	Co-benefit %	Co-benefit, oz	Comments
Ameren	DUCK CREEK	1	BIT	SCR	Wet FGD	Cold-side ESP	90% or 0.008	2,278	
Ameren	NEWTON	1	SUB	None	None	Cold-side ESP	0	0	
Ameren	NEWTON	2	SUB	None	None	Cold-side ESP	0	0	
Ameren	E D EDWARDS	1	SUB	None	None	Cold-side ESP	0	0	
Ameren	E D EDWARDS	2	SUB	None	None	Cold-side ESP	0	0	
Ameren	E D EDWARDS	3	SUB	SCR	None	Cold-side ESP	0	0	
Ameren	COFFEEN	01	BIT	SCR	None	Cold-side ESP	30%	744	
Ameren	COFFEEN	02	BIT	SCR	None	Cold-side ESP	30%	1,307	
Ameren	HUTSONVILLE	05	SUB	None	None	Cold-side ESP	0	0	Expected to switch to PRB coal as high S coal in inventory is used up
Ameren	HUTSONVILLE	06	SUB	None	None	Cold-side ESP	0	0	
Ameren	MEREDOSIA	01	BIT	None	None	Cold-side ESP	30%	11	Expected to use TTBS. Use TTBS injection rates
Ameren	MEREDOSIA	02	BIT	None	None	Cold-side ESP	30%	10	
Ameren	MEREDOSIA	03	BIT	None	None	Cold-side ESP	30%	19	
Ameren	MEREDOSIA	04	BIT	None	None	Cold-side ESP	30%	20	
Ameren	MEREDOSIA	05	SUB	None	None	Cold-side ESP	0	0	
CWLP	DALLMAN	31	BIT	SCR	Wet FGD	Cold-side ESP	90%	646	
CWLP	DALLMAN	32	BIT	SCR	Wet FGD	Cold-side ESP	90%	631	
CWLP	DALLMAN	33	BIT	SCR	Wet FGD	Cold-side ESP	90%	1,383	
Dynegy	BALDWIN	1	SUB	SCR	None	Cold-side ESP	80%	5,951	To add FF in 2010, TOXECON assumed
Dynegy	BALDWIN	2	SUB	SCR	None	Cold-side ESP	80%	5,767	To add FF in 2011, TOXECON assumed
Dynegy	BALDWIN	3	SUB	None	None	Cold-side ESP	80%	6,409	To add FF in 2012, TOXECON assumed
Dynegy	HAVANA	9	SUB	SCR	None	Hot-side ESP	0	0	To add FF in 2012, TOXECON assumed
Dynegy	HENNEPIN	1	SUB	None	None	Cold-side ESP	0	0	
Dynegy	HENNEPIN	2	SUB	None	None	Cold-side ESP	0	0	
Dynegy	VERMILION	1	BIT	None	None	Cold-side ESP	30%	158	To add FF and SI in 2007, TOXECON assumed
Dynegy	VERMILION	2	BIT	None	None	Cold-side ESP	30%	239	To add FF and SI in 2007, TOXECON assumed
Dynegy	WOOD RIVER	4	SUB	None	None	Cold-side ESP	0	0	
Dynegy	WOOD RIVER	5	SUB	None	None	Cold-side ESP	0	0	
Joppa	JOPPA STEAM	1	SUB	None	None	Cold-side ESP	0	0	

Joppa	JOPPA STEAM	2	SUB	None	None	Cold-side ESP	0	0	
Joppa	JOPPA STEAM	3	SUB	None	None	Cold-side ESP	0	0	
Joppa	JOPPA STEAM	4	SUB	None	None	Cold-side ESP	0	0	
Joppa	JOPPA STEAM	5	SUB	None	None	Cold-side ESP	0	0	
Joppa	JOPPA STEAM	6	SUB	None	None	Cold-side ESP	0	0	
Kincaid	KINCAID	1	SUB	SCR	None	Cold	0	0	
Kincaid	KINCAID	2	SUB	SCR	None	Cold	0	0	
Marion	MARION	4	BIT	SCR	Wet FGD	Cold	90%	1,478	
Marion	MARION	123	BIT	CFB-SNCR	None	Fabric Filter	90%	973	
Midwest	JOLIET 29	71	SUB	None	None	Cold-side ESP	0	0	
Midwest	JOLIET 29	72	SUB	None	None	Cold-side ESP	0	0	
Midwest	JOLIET 29	81	SUB	None	None	Cold-side ESP	0	0	
Midwest	JOLIET 29	82	SUB	None	None	Cold-side ESP	0	0	
Midwest	JOLIET 9	5	SUB	None	None	Cold-side ESP	0	0	
Midwest	CRAWFORD	7	SUB	None	None	Cold-side ESP	0	0	
Midwest	CRAWFORD	8	SUB	None	None	Cold-side ESP	0	0	
Midwest	POWERTON	51	SUB	None	None	Cold-side ESP	0	0	
Midwest	POWERTON	52	SUB	None	None	Cold-side ESP	0	0	
Midwest	POWERTON	61	SUB	None	None	Cold-side ESP	0	0	
Midwest	POWERTON	62	SUB	None	None	Cold-side ESP	0	0	
Midwest	WAUKEGAN	17	SUB	None	None	Cold-side ESP	0	0	
Midwest	WAUKEGAN	7	SUB	None	None	Hot-side ESP	0	0	TOXECON assumed
Midwest	WAUKEGAN	8	SUB	None	None	Cold-side ESP	0	0	
Midwest	WILL COUNTY	1	SUB	None	None	Cold-side ESP	0	0	
Midwest	WILL COUNTY	2	SUB	None	None	Cold-side ESP	0	0	
Midwest	WILL COUNTY	3	SUB	None	None	Hot-side ESP	0	0	TOXECON assumed
Midwest	WILL COUNTY	4	SUB	None	None	Cold-side ESP	0	0	
Midwest	FISK	19	SUB	None	None	Cold-side ESP	0	0	

Question: *What revisions would be made to Dr. Staudt's cost estimates after the information provided in the hearing?*

Answer: *Response from James E. Staudt, Ph.D., CFA:*

I have also prepared revised Tables 8.7, 8.9, and 8.10 that incorporates the following revisions.

- Revisions based upon my understanding of the coal types
- Revisions/Corrections of fly ash costs shown in the original tables in the TSD
- Revisions to sorbent injection rates due to revised coal types and understanding of the configurations
- Revisions/Corrections of sorbent costs assuming that the four Meredosia units use the TTBE

In addition, as requested in the hearing, I have prepared a cost for additional fly ash expense associated with operating the Baldwin units with cold-side ESP's during 2009-2012 and some additional cost for installing the Havana fabric filter earlier than 2012.

As shown in the revised Table 8.7, the costs are close to what was originally estimated, albeit, slightly higher due to the higher cost of sorbent assumed. Importantly, the difference in annual costs between the IL rule and CAMR are in the same range as originally stated in the TSD – about $36 million. Including the additional costs described for Baldwin and Havana associated with the timing of the fabric filters, the annualized cost differential between the IL Rule and CAMR remains below $40 million for the years 2009-2012.

Table 8.7 Estimated Cost for IL Utilities of Complying with IL Mercury Rule and with 2010 CAMR

Cost	Units	IL Rule	2010 CAMR
Capital Cost	$1000	$75,135	$33,558
Annualized Capital Cost (14% CRF)	$1000	$10,519	$4,698
Annual Sorbent Cost	$1000	$46,374	$19,838
Annual Ash Disposal Cost	$1000	$13,461	$10,041
Annualized TOXECON O&M (excluding sorbent)	$1000	$425	$0
Total Annual Cost	$1000	$70,779	$34,577
Ounces Hg removed *	1000 ounces	124**	90
Cost per oz Hg removed *	$/ounce	$572**	$385
Cost per lb Hg removed *	$/lb	$9,158 **	$6,161

NOTE: columns may not add due to rounding

*No credit is taking for Hg reductions from cobenefits (-28,000 oz) because these would happen regardless of IL rule or CAMR

** This is estimated from 90% removal. As described in Revised Table 8.9, expected removal is higher than shown here and therefore expected cost per ounce or pound is actually lower

Revised Table 8.9

Owner	Plant Name	Technology	Cost, $1000	Sorbent Cost $1000/yr	TOXECON O&M	Ash disposal, $1000	Estimated Annual Coal Use (1000 tons)	90% removal*		Expected removal*	
								Hg reduced, oz/yr	Hg Output, oz/yr	Hg reduced, oz/yr	Hg Output, oz/yr
Ameren	DUCK CREEK	Cobenefit	$0	$0	$0	$0	989	2,278	253	2,278	253
Ameren	NEWTON	SI	$1,543	$2,062	$0	$2,550	2,220	6,394	710	6,608	497
Ameren	NEWTON	SI	$1,543	$2,129	$0	$0	2,172	6,254	695	6,463	486
Ameren	E D EDWARDS	SI	$340	$372	$0	$0	449	1,295	144	1,338	101
Ameren	E D EDWARDS	SI	$703	$800	$0	$0	909	2,618	291	2,705	204
Ameren	E D EDWARDS	SI	$903	$1,186	$0	$0	1,211	3,486	387	3,603	271
Ameren	COFFEEN	SI	$973	$2,574	$0	$0	968	2,231	248	2,306	174
Ameren	COFFEEN	SI	$1,543	$4,536	$0	$0	1,702	3,922	436	4,052	305
Ameren	HUTSONVILLE	SI	$190	$167	$0	$0	187	538	60	556	42
Ameren	HUTSONVILLE	SI	$193	$211	$0	$0	236	681	76	704	53
Ameren	MEREDOSIA	SI	$78	$54	$0	$0	14	32**	4	33**	3
Ameren	MEREDOSIA	SI	$78	$54	$0	$0	13	31**	3	32**	2
Ameren	MEREDOSIA	SI	$78	$109	$0	$0	25	58**	6	60**	4
Ameren	MEREDOSIA	SI	$78	$109	$0	$0	27	61**	7	63**	5
Ameren	MEREDOSIA	SI	$598	$681	$0	$0	721	2,077	231	2,147	162
CWLP	DALLMAN	Cobenefit	$0	$0	$0	$0	281	646	72	646	72
CWLP	DALLMAN	Cobenefit	$0	$0	$0	$0	274	631	70	631	70
CWLP	DALLMAN	Cobenefit	$0	$0	$0	$0	600	1,383	154	1,383	154
Dynegy	BALDWIN****	TOXECON	$1,558	$353***	$0	$0	2,324	6,694	744	6,917	521
Dynegy	BALDWIN****	TOXECON	$1,588	$365***	$0	$0	2,253	6,487	721	6,704	505
Dynegy	BALDWIN****	TOXECON	$1,588	$406***	$0	$0	2,504	7,211	801	7,451	561
Dynegy	HAVANA****	TOXECON	$1,220	$575	$0	$0	1,190	3,428	381	3,542	267
Dynegy	HENNEPIN	SI	$185	$243	$0	$625	276	795	88	822	62
Dynegy	HENNEPIN	SI	$578	$797	$0	$0	874	2,517	280	2,601	196
Dynegy	VERMILION****	SI	$0****	$126	$0	$0	206	474	53	490	37
Dynegy	VERMILION****	SI	$0****	$200	$0	$0	311	716	80	740	56
Dynegy	WOOD RIVER	SI	$283	$309	$0	$1,200	351	1,010	112	1,044	79
Dynegy	WOOD RIVER	SI	$930	$1,060	$0	$0	1,048	3,017	335	3,117	235
Joppa	JOPPA STEAM	SI	$458	$802	$0	$0	819	2,360	262	2,439	184
Joppa	JOPPA STEAM	SI	$458	$802	$0	$0	814	2,345	261	2,423	182

Joppa	JOPPA STEAM	SI	$458	$802	$0	$0	822	2,366	263	2,445	184
Joppa	JOPPA STEAM	SI	$458	$822	$0	$0	842	2,424	269	2,505	189
Joppa	JOPPA STEAM	SI	$458	$852	$0	$4,350	875	2,519	280	2,603	196
Joppa	JOPPA STEAM	SI	$458	$852	$0	$0	869	2,503	278	2,586	195
Kincaid	KINCAID	SI	$1,650	$1,808	$0	$0	1,824	5,252	584	5,427	408
Kincaid	KINCAID	SI	$1,650	$2,169	$0	$0	2,122	6,110	679	6,314	475
Marion	MARION	Cobenefit	$0	$0	$0	$0	642	1,478	164	1,478	164
Marion	MARION	Cobenefit	$0	$0	$0	$0	422	973	108	973	108
Midwest	JOLIET 29	SI	$825	$723	$0	$0	766	2,206	245	2,280	172
Midwest	JOLIET 29	SI	$825	$886	$0	$0	939	2,703	300	2,793	210
Midwest	JOLIET 29	SI	$825	$904	$0	$0	958	2,758	306	2,850	215
Midwest	JOLIET 29	SI	$825	$904	$0	$0	958	2,758	306	2,850	215
Midwest	JOLIET 9	SI	$900	$1,578	$0	$2,625	1,420	4,089	454	4,225	318
Midwest	CRAWFORD	SI	$598	$668	$0	$825	755	2,175	242	2,248	169
Midwest	CRAWFORD	SI	$895	$1,020	$0	$0	1,119	3,223	358	3,331	251
Midwest	POWERTON	SI	$1,116	$1,468	$0	$0	1,520	4,376	486	4,522	340
Midwest	POWERTON	SI	$1,116	$1,370	$0	$0	1,418	4,085	454	4,221	318
Midwest	POWERTON	SI	$1,116	$1,370	$0	$0	1,418	4,085	454	4,221	318
Midwest	POWERTON	SI	$1,116	$1,345	$0	$0	1,393	4,012	446	4,145	312
Midwest	WAUKEGAN	SI	$303	$398	$0	$636	446	1,284	143	1,327	100
Midwest	WAUKEGAN	TOXECON	$19,680	$539	$241	$0	1,106	3,185	354	3,185	354
Midwest	WAUKEGAN	SI	$888	$1,206	$0	$0	1,217	3,504	389	3,621	273
Midwest	WILL COUNTY	SI	$470	$257	$0	$250	286	824	92	851	64
Midwest	WILL COUNTY	SI	$460	$302	$0	$0	343	988	110	1,021	77
Midwest	WILL COUNTY	TOXECON	$17,940	$409	$183	$0	858	2,472	275	2,472	275
Midwest	WILL COUNTY	SI	$1,495	$1,638	$0	$0	1,653	4,762	529	4,921	370
Midwest	FISK	SI	$935	$1,004	$0	$400	996	2,869	319	2,964	223
Total	0	0	**$75,135**	**$46,374**	**$425**	**$13,461**	**53,953**	**151,657**	**16,851**	**156,277**	**12,230**

** Over 90% overall removal has been shown, particularly on PRB fired units, at injection rates of about 3 lb/MMacf. Nearly all of the unscrubbed units in IL fire PRB coal. As a result, slightly better than 90% removal is expected at the costs shown here.*
*** Because Meredosia 1-4 are using high sulfur coal at this time and are not – as far as I know – planning to change coals, 90% removal at these small units may not be achieved. However, because of their small size and limited use, they have little impact on the overall mercury removal state-wide.*
**** Baldwin is already reportedly achieving 80% removal of mercury. There is a good chance that with the addition of a fabric filter the Baldwin units will achieve adequate removal without any sorbent. Therefore, this cost may go to zero.*
***** For 2009-2012 Baldwin and Havana will likely have additional costs since the fabric filters will not be installed prior to 2009. Fabric filters at Baldwin, Havana and Vermillion are installed due to Consent Decree, as is SI at Vermillion. Capital cost of fabric filters is not attributed to IL rule, but sorbent injection is in the case of Baldwin and Havana.*

Revised Table 8.10

Owner	Plant Name	Capacity MW	Technology	Cost, $1000	Sorbent Cost $1000/yr	TOXECON O&M	Ash disposal, $1000	Estimated Annual Coal Use (1000 tons)	Hg reduced	Hg Output
Ameren	DUCK CREEK	441	Cobenefit	$0	$0	$0	$0	989	2,278	253
Ameren	NEWTON	617		$0	$0	$0	$0	2,220	0	7,105
Ameren	NEWTON	617	SI	$1,543	$887	$0	$1,275	2,172	4,864	2,085
Ameren	E D EDWARDS	136	SI	$340	$155	$0	$0	449	1,007	432
Ameren	E D EDWARDS	281	SI	$703	$334	$0	$0	909	2,036	873
Ameren	E D EDWARDS	361	SI	$903	$494	$0	$0	1,211	2,712	1,162
Ameren	COFFEEN	389	SI	$973	$1,716	$0	$0	968	1,736	744
Ameren	COFFEEN	617	SI	$1,543	$3,024	$0	$0	1,702	3,050	1,307
Ameren	HUTSONVILLE	76	SI	$190	$213	$0	$0	130	233	100
Ameren	HUTSONVILLE	77	SI	$193	$270	$0	$0	165	295	127
Ameren	MEREDOSIA	31		$0	$0	$0	$0	20	0	64
Ameren	MEREDOSIA	31		$0	$0	$0	$0	19	0	61
Ameren	MEREDOSIA	31		$0	$0	$0	$0	36	0	115
Ameren	MEREDOSIA	31		$0	$0	$0	$0	38	0	122
Ameren	MEREDOSIA	239	SI	$598	$284	$0	$0	721	1,616	692
CWLP	DALLMAN	87.5	Cobenefit	$0	$0	$0	$0	281	646	72
CWLP	DALLMAN	86	Cobenefit	$0	$0	$0	$0	274	631	70
CWLP	DALLMAN	207	Cobenefit	$0	$0	$0	$0	600	1,383	154
Dynegy	BALDWIN**	623	TOXECON	$1,558	$353*	$0	$0	2,324	6,694	744
Dynegy	BALDWIN**	635	TOXECON	$1,588	$365*	$0	$0	2,253	6,487	721
Dynegy	BALDWIN**	635	TOXECON	$1,588	$406*	$0	$0	2,504	7,211	801
Dynegy	HAVANA**	488	TOXECON	$1,220	$575	$0	$0	1,190	3,428	381
Dynegy	HENNEPIN	74	SI	$185	$101	$0	$625	276	619	265
Dynegy	HENNEPIN	231	SI	$578	$332	$0	$0	874	1,958	839
Dynegy	VERMILION**	74	TOXECON	$0	$126	$0	$0	206	474	53
Dynegy	VERMILION**	109	TOXECON	$0	$200	$0	$0	311	716	80
Dynegy	WOOD RIVER	113	SI	$283	$129	$0	$1,200	351	786	337
Dynegy	WOOD RIVER	372	SI	$930	$442	$0	$0	1,048	2,346	1,006
Joppa	JOPPA STEAM	183	SI	$458	$334	$0	$0	819	1,836	787
Joppa	JOPPA STEAM	183	SI	$458	$334	$0	$0	814	1,824	782
Joppa	JOPPA STEAM	183	SI	$458	$334	$0	$2,900	822	1,840	789
Joppa	JOPPA STEAM	183	SI	$458	$342	$0	$0	842	1,885	808
Joppa	JOPPA STEAM	183		$0	$0	$0	$0	875	0	2,799
Joppa	JOPPA STEAM	183		$0	$0	$0	$0	869	0	2,781

1Kincaid	KINCAID	660	SI	$1,650	$753	$0	$0	1,824	4,085	1,751
Kincaid	KINCAID	660	SI	$1,650	$904	$0	$0	2,122	4,753	2,037
Marion	MARION	170	Cobenefit	$0	$0	$0	$0	642	1,478	164
Marion	MARION	120	Cobenefit	$0	$0	$0	$0	422	973	108
0Midwest	JOLIET 29	330	SI	$825	$301	$0	$0	766	2,206	245
Midwest	JOLIET 29	330	SI	$825	$369	$0	$0	939	2,703	300
Midwest	JOLIET 29	330	SI	$825	$377	$0	$0	958	2,758	306
Midwest	JOLIET 29	330	SI	$825	$377	$0	$0	958	2,758	306
Midwest	JOLIET 9	360	SI	$900	$657	$0	$2,625	1,420	4,089	454
Midwest	CRAWFORD	239	SI	$598	$278	$0	$825	755	2,175	242
Midwest	CRAWFORD	358	SI	$895	$425	$0	$0	1,119	3,223	358
Midwest	POWERTON	446.5	SI	$1,116	$611	$0	$0	1,520	4,376	486
Midwest	POWERTON	446.5	SI	$1,116	$571	$0	$0	1,418	4,085	454
Midwest	POWERTON	446.5	SI	$1,116	$571	$0	$0	1,418	4,085	454
Midwest	POWERTON	446.5	SI	$1,116	$561	$0	$0	1,393	4,012	446
Midwest	WAUKEGAN	121		$0	$0	$0	$0	446	0	1,427
Midwest	WAUKEGAN	328		$0	$0	$0	$0	1,106	0	3,539
Midwest	WAUKEGAN	355		$0	$0	$0	$0	1,217	0	3,894
Midwest	WILL COUNTY	188	SI	$470	$107	$0	$191	286	824	92
Midwest	WILL COUNTY	184	SI	$460	$126	$0	$0	343	988	110
Midwest	WILL COUNTY	299		$0	$0	$0	$0	858	0	2,747
Midwest	WILL COUNTY	598	SI	$1,495	$682	$0	$0	1,653	4,762	529
Midwest	FISK	374	SI	$935	$418	$0	$400	996	2,869	319
Total				**$33,558**	**$19,838**	**$0**	**$10,041**	**53,859**	**117,794**	**50,275**

**Baldwin is already reportedly achieving 80% removal of mercury. There is a good chance that with the addition of a fabric filter the Baldwin units will achieve adequate removal without any sorbent. Therefore, this cost may go to zero.*
*** For 2009-2012 Baldwin and Havana will likely have additional costs since the fabric filters will not be installed prior to 2009. Fabric filters at Baldwin, Havana and Vermillion are installed due to Consent Decree, as is SI at Vermillion. Capital cost of fabric filters is not attributed to IL rule, but sorbent injection is in the case of Baldwin and Havana.*

Baldwin and Havana

During the hearing it was pointed out that the costs of fly ash disposal would be higher than what was shown for the Baldwin plant due to the installation of a fabric filter after the 2009 start date for the IL rule. As a result, this plant would not fully realize the benefits of a TOXECON system until the fabric filters were installed.

For Baldwin, the costs associated with additional ash disposal costs (in $1000's) for each year can be estimated. The table below shows estimated costs assuming that the differential costs are $25/ton for ash that was sold and must be disposed of as a result of sorbent injection. However, according to Table 8.8 of the TSD, which shows that Baldwin is able to dispose of fly ash in ash ponds at little or no cost, the $25/ton cost for disposal of ash used is probably very high. The actual cost is likely a small fraction of what is estimated at $25/ton, and is likely to be closer to what is shown for the estimated costs using only the lost revenue from Table 8.8. Since this estimate assumes that the fabric filters are installed on the last day of the year, and they are likely to be installed prior to that, these costs are the highest that they can be. Therefore, I expect that these estimates of ash disposal cost for these years are very high. After 2012, these costs would not apply since the TOXECON systems would be installed. For these years, sorbent costs would also be higher since they would be injecting upstream of an ESP instead of a fabric filter. And, the additional cost of sorbent over what is shown in revised Table 8.9 is shown below.

Estimated fly ash costs	2009 (half year)	2010	2011	2012
at $25/ton, $1000	1,263	2,525	1,680	840
at cost of lost fly ash revenue from Table 8.8, $1000	6	11	7	4
Estimated additional sorbent costs at $0.90/lb, $1,000	205	410	273	137

The Havana unit would have to install their fabric filter early since the proposed rule does not provide a TTBE for units with a hot-side ESP. As a result, they would incur an additional cost associated with early installation. This would be equal to a cost of capital times the installed cost. At 488 MW, if the cost of the fabric filter is $60/kw, the cost of a fabric filter would be about $29 million. At a 5.69% annual yield (current 5 year AAA corporate yield, per Bloomberg on 7/12/06), this is an annual cost of $1.66 million for the years 2009-2012 (actually, $0.83 million in 2009 since it's half a year). Although Dynegy probably uses a higher cost of capital than AAA bond yields when it builds a power plant or buys one, it is customary for corporations to match the cost of capital to the risk of a project. In this case Dynegy would simply be performing an environmental project a few years earlier, which does not bear nearly the same risk as a project that has far more business risk. Moreover, the cost of capital effects would actually be mitigated by the effects of escalation of labor and material. In fact, there would be a net financial benefit to performing the project earlier if material and labor escalation is at a higher rate than the cost of capital.

Further Amendment/Clarification to Hearing testimony from James E. Staudt, Ph.D., CFA:

During the hearing I was questioned on my contribution to an article published in Environmental Science and Technology titled "Control of Mercury Emissions from Coal-Fired Electric Utility Boilers" coauthored with Ravi Srivastava, Nick Hutson, Blair Martin and Frank Princiotta of US EPA. At the time of the hearing I did not properly recall when I contributed to this article. Since the hearing, I have had the opportunity to check the timing of my work on this. This article originates from work I performed for US EPA in late 2004. US EPA used this work in its White Paper entitled "Control of Mercury Emissions from Coal Fired Electric Utility Boilers: An Update" issued on February 18, 2005 by US EPA's Office of Research and Development that is referenced in the TSD. The material in this White Paper as well as work by others at US EPA was subsequently used to form a basis of the Environmental Science and Technology journal article that was entered into evidence. That the article took until spring of 2006 to get published probably reflects the slow process of integrating other peoples work, the slow process of getting an article published in a prestigious journal and the slow process of getting such an article through US EPA administrative review on such a sensitive issue as mercury. For this reason, I believe that the article does not accurately reflect the current state of technology, which has advanced rapidly in the time since 2004 when I originally did the work for US EPA.

To be clear, my work with US EPA is specifically limited to technology and cost studies. Any conclusions of a policy nature in the White Paper or in the journal article, such as regarding the timing of availability of technology for complying with regulations, better reflect the official policy position of the US EPA than my opinion. The section of the journal article "Outlook for technology availability" clearly states that the opinions expressed regarding technology availability are those of US EPA. These statements in the article that I coauthored are correct statements because they are, in fact, US EPA's official policy position. Whether I agree or disagree with US EPA's policy position is another matter. It is my opinion that the US EPA positions in the Environmental Science and Technology article regarding technology availability should not be taken to mean that technology is not yet available for the applications we are discussing in Illinois, although technology may or may not currently be available for other applications. It is my opinion that the technology is available as described in the TSD and as I have described in my other testimony.

Question: *What is the average daily flow from all NPDES permits?*

Answer: Based on our information, the average daily flow from all NPDES permittees is 21,140 million gallons per day. This includes cooling water flows from power plants (they intake river water, run it past hot equipment and then discharge it back to the river) which are very voluminous.

ADDITIONAL DOCUMENTS REQUESTED DURING THE JUNE 12, 2006 HEARING

Attachment 1: Scope of Work Proportion from ICF Contract

Attachment 2: Scope of Work Proportion from Richard Ayres' Contract

Attachment 3: Scope of Work Proportion from Gerald Keeler's Contract

Attachment 4: Control Configuration Inspections at Illinois Coal-Fired Power Plants – 2006 (provided to the Board as complete copies and redacted copies for the public record)

Attachment 5: Illinois Environmental Protection Agency comments to the U. S. Environmental Protection Agency regarding Proposed National Emission Standards for Hazardous Air Pollutants; and in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Untis, Proposed Rule; Propose Rule (69 *Federal Register* 4652, January 30, 2004) ("Proposal") and Supplemental Notice for the Proposal (69 *Federal Register* 2397, March 16, 2004)

Attachment 6: IPM modeling data (Compact Disk, provided only to Board and Counsel for: Ameren, Dynegy, Midwest Generation, Kincaid, Chicago Legal Clinic, and Environmental Law and Policy Center)

Attachment 7: "Blood and Hair Mercury Levels in Young Children and Women of Childbearing Age --- United States 1999"

Attachment 8: Prairie State comments to the Illinois Environmental Protection Agency on the Temporary Technology Based Extension – Beginning with email from Dianna Tickner to Laurel Kroack

Respectfully submitted,

By: ______________

Charles E. Matoesian
Assistant Counsel
Division of Legal Counsel

Dated: July 28, 2006

Illinois Environmental Protection Agency
1021 North Grand Avenue East
P.O. Box 19276
Springfield, Illinois 62794-9276

STATE OF ILLINOIS)
) **SS**
COUNTY OF SANGAMON)
)

CERTIFICATE OF SERVICE

I, the undersigned, an attorney, state that I have served the attached POST-HEARING COMMENTS OF THE ILLINOIS ENVIRONMENTAL PROTECTION AGENCY upon the person to whom it is directed, by placing a copy in an envelope addressed to:

Dorothy Gunn, Clerk
Illinois Pollution Control Board
James R. Thompson Center
100 West Randolph St., Suite 11-500
Chicago, IL 60601-3218
(Overnight Mail)

SEE ATTACHED SERVICE LIST
(First Class Mail)

and mailing it Springfield, Illinois, with sufficient postage affixed, as indicated above.

ILLINOIS ENVIRONMENTAL
PROTECTION AGENCY

By: ____________________
Charles E. Matoesian
Assistant Counsel
Division of Legal Counsel

DATED: July 28, 2006

Illinois Environmental Protection Agency
1021 North Grand Avenue East
P.O. Box 19276
Springfield, Illinois 62794-9276

SERVICE LIST 06-25

Marie Tipsord
Hearing Officer
Illinois Pollution Control Board
James R. Thompson Center
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Houston, TX 77002

ICF CONSULTING

February 17, 2006

Mike Koerber
Executive Director
Lake Michigan Air Directors Consortium/
Midwest Regional Planning Organization
2250 East Devon Avenue, Suite 250
Des Plaines, Illinois 60018

Jim Ross
Division of Air Pollution Control, Bureau of Air
Illinois EPA
P.O. Box 19276,
1021 N. Grand Ave., East,
Springfield, IL 62794-9276

Re: Request for Proposal: Illinois EPA Modeling of Mercury Rule

Dear Mike and Jim:

ICF is pleased to provide the Lake Michigan Air Directors Consortium (LADCO) with the attached proposal for providing additional modeling and other work in support of the Illinois Mercury Rule. The scope of work outlined here is based on the Illinois EPA's (IEPA) scope outlined in a memo dated 1/26/06 and a conversation between ICF and Illinois EPA on February 1, 2006.

Task 1 Modify NEEDs and 3 IPM runs and Supporting Parsings

Illinois EPA would like to make additional modifications to the VISTAS/LADCO case in order to incorporate new information on specific unit characterizations. IEPA has already forwarded those changes to ICF for review. ICF will discuss any issues related to the date with IEPA and incorporate the changes as appropriate. In addition, IEPA would like to incorporate new mercury control technology data.

Once this new information is incorporated, Illinois EPA requires three new IPM runs:

- A. A base case run based on the modified VISTAS/LADCO case without CAIR or CAMR in place, but including Title IV and NOx SIP Call requirements.
- B. A Base Case Run with CAIR and CAMR in place.
- C. A Policy run with the CAIR in place, the Illinois Mercury Rule (specified in your email of February 1) for Illinois plants, and CAMR for non-Illinois plants.

We will provide you with run specs for your review and approval before implementing these runs. Full implementation, QA/QC for the first of these runs could be completed by February 27. We would expect to complete the third run By March 3. Summary data will be developed to report on the impacts of the CAIR mercury rule in isolation (Run C vs. Run A) as well as the incremental impacts of the Illinois rule (Run C vs. R run B). The total impacts of the Illinois Rule would be a cost comparison of Run C vs. Run A.

Task 2: Parsing of Runs Expanded IPM Run Data and Other Cost Information for LADCO (Item 1-4)

In support of its work, LADCO would like some additional information on cost and other impacts. We have budgeted for three runs, three years each (9 parsings). These will be completed by March 8

Key information to be provided in addition to the parsed results would be the impacts on costs per kWh of the Illinois rule. We will provide information on the change in average production cost per kWh for Illinois due to the rule as well as the change in the marginal cost of production (i.e., the IPM wholesale energy price). Impacts of coal plants (retirements and retrofits) and emissions data will also be provided

We will also provide impacts on costs from the Illinois Rule vs. the CAMR Rule (Run C vs. Run B) in terms of average and marginal cost per kWh. The other indicators -- $/month to the different consuming sectors will require some discussion with IEPA. As we have indicated, IPM provides forecast at the wholesale level, and therefore forecast wholesale marginal power prices. In order to estimate retail price impacts we could (1) apply the tool that EPA uses to produce these estimates at the regional (the MANO region) average level for all sectors, or (2) implement a simpler approach to get at retail sectors. Option 1 could be implemented for this work, but the result will not have any sectoral detail, and will be based on the current EPA tool. There is insufficient time to update this tool to more recent data (i.e., AEO 2006). Option 2 will require some estimate of the total expenditures at the average household or establishment level, and an estimate of the relationship between changes in wholesale prices and retail rates (e.g., wholesale prices represent x percent of retail; or all marginal prices will be added to a base forecast).

Other questions related to impacts on health benefits, jobs, pollution control industry, and the economy at large is something we could potentially assist you with, but not within the timeframe that you require. Therefore, we have not included this in the current scope.

Task 3. Reduced Permits for RE/EE Set Aside

This run is a simple reduction in the available NO_X allowances under the CAIR rule for Illinois units. This run would be done off of the existing VISTAS/LADCO CAIR/CAMR run (LADCO_IL_BC_02e) with revised CAIR annual and summer NOx caps and the NOx allowance supplementary pool. The NOx caps and the NOx allowance supplementary pool will be adjusted to reflect a retirement of 30% of the IL NOx budget. As we understand, this run would not need to be parsed and state level outputs will be provided. This run would be completed by February 24.

Task 4 Reporting

You have asked for an executive level summary that highlights and explains the summary results in addition to a more lengthy report. We envision a report with an executive summary of 3-5 pages addressing key issues such as the cost of the mercury rule (with CAIR/CAMR for the rest of the nation) vs. the CAIR/CAMR, the implications of the rule for key system indicators identified (e.g., retirements, generation, rates, coal consumption) with a focus on Illinois results. The focus would be on the difference between the Illinois rule vs. the CAIR/CAMR. The goal would be to hit the highlights of the findings.

The remainder of the report would provide more in depth results. We would expect this to be a 20 to 30-page report that goes into more depth into the modeling platform, the inputs, outputs, and results, with the focus on explaining the impacts of the Illinois rule. The expected audience would be someone u unfamiliar with the modeling and therefore, the need for more detailed discussion of findings and explanation of the results. We would develop a draft report by March 8. We would feed you preliminary background material as we develop it so you have some time to absorb and process it. However, the first full draft of a report you would see would be March 8h. I have not budgeted for revisions beyond that first draft.

Next Steps

Please call if you have questions. If you would like to proceed, you may sign the attached form in duplicate and return it to my attention. We look forward to working with the LADCO and Illinois EPA on this project.

Sincerely,

Juanita M. Haydel
Senior Vice President

I hereby authorize ICF Consulting to proceed according to the scope of work described above.

Accepted* (including Attachments A and B) *for	***Accepted for***
Lake Michigan Air Directors Consortium	**ICF Resources, LLC**
Signature: ____________________	*Signature* ____________________
Printed Name: ____________________	*Printed Name:* ____________________
Title: ____________________	*Title:* ____________________
Date: ____________________	*Date:* ____________________

Ayres Law Group

January 17, 2006

Mr. Michael Koerber, President
Lake Michigan Air Directors Consortium
2250 East Devon Ave. Suite 250
Des Plaines IL, 60018

Re: State of Illinois, Environmental Protection Agency: Mercury Emissions Control Regulation

Dear Mike

I am extremely pleased that the Lake Michigan Air Directors Consortium (LADCO) wishes to retain Ayres Law Group (Ayres) to provide advice and counsel concerning the Illinois EPA, Bureau of Air Bureau's forthcoming regulation to control emissions of mercury from electric power generating units.

This letter and the accompanying Client Representation Memorandum set out the terms of this engagement, including the fee arrangement that we have agreed upon. As we discussed, my fees for this matter will be paid by LADCO , and will be billed at a reduced governmental trade association rate. Ayres will keep the appropriate person at the Bureau up to date with respect to fees billed to LADCO. Ayres will not under t this agreement state or indicate in any other way that it represents, or speaks for, the member states of LADCO, other than Illinois.

If you agree with the terms as described in these two documents, please sign this engagement letter and return the original to me in the enclosed envelope.

I appreciate the opportunity to provide counsel to LADCO and its member State in this important matter, and I will do my best to deliver a positive outcome as efficiently as possible.

Sincerely yours,

Richard Ayres

Richard E. Ayres
Ayres Law Group

Agreed:

Paul Dubenetzky, Chair
Lake Michigan Air Directors Consortium

Kevin Kessler, Treasurer
Lake Michigan Air Directors Consortium

3-10-06
Date

Ayres Law Group

MEMORANDUM REGARDING PROFESSIONAL SERVICES

This Memorandum sets forth the terms and conditions under which Ayres Law Group ("Ayres") undertakes to provide professional services to the Lake Michigan Air Directors Consortium ("LADCO") to assist the Illinois Environmental Protection Agency ("Illinois EPA") in the matter described in the accompanying engagement letter.

1 **Scope of Services.** Ayres undertakes to provide services to LADCO to assist the Illinois EPA solely in connection with the matter described in the accompanying engagement letter. In the event that LADCO requests Ayres to undertake additional matters or the scope of work is expanded, such additional work will not be governed by the terms and conditions of this agreement unless mutually agreed otherwise. Except as provided in Section 6 of this Agreement, Ayres' services will be deemed concluded at the time that Ayres has rendered its final bill for services on the matter described in our engagement letter or any such additional matters.

Ayres' services are limited to LADCO and the State of Illinois.

February 16, 2006

Gerald Keeler, Ph.D.
Professor, Environmental Health Sciences
Professor, Atmospheric, Oceanic and Space Sciences
University of Michigan
1530 SPH I
109 South Observatory
Ann Arbor, Michigan 48109-2029

Dear Gerald:

On behalf of the Lake Michigan Air Directors Consortium (LADCO), I wish to award you a contract to provide technical support for the State of Illinois in developing a rule for controlling mercury emissions from power plants. Specific support shall include the following activities, as directed by the State of Illinois (or LADCO):

- preparation and review of technical documents;
- participation in stakeholder meetings, as needed;
- testimony at hearings;
- technical assistance to key staff; and
- other technical support agreed to by you and Illinois (or LADCO).

Control Configuration Inspections at Illinois Coal-Fired Power Plants - 2006

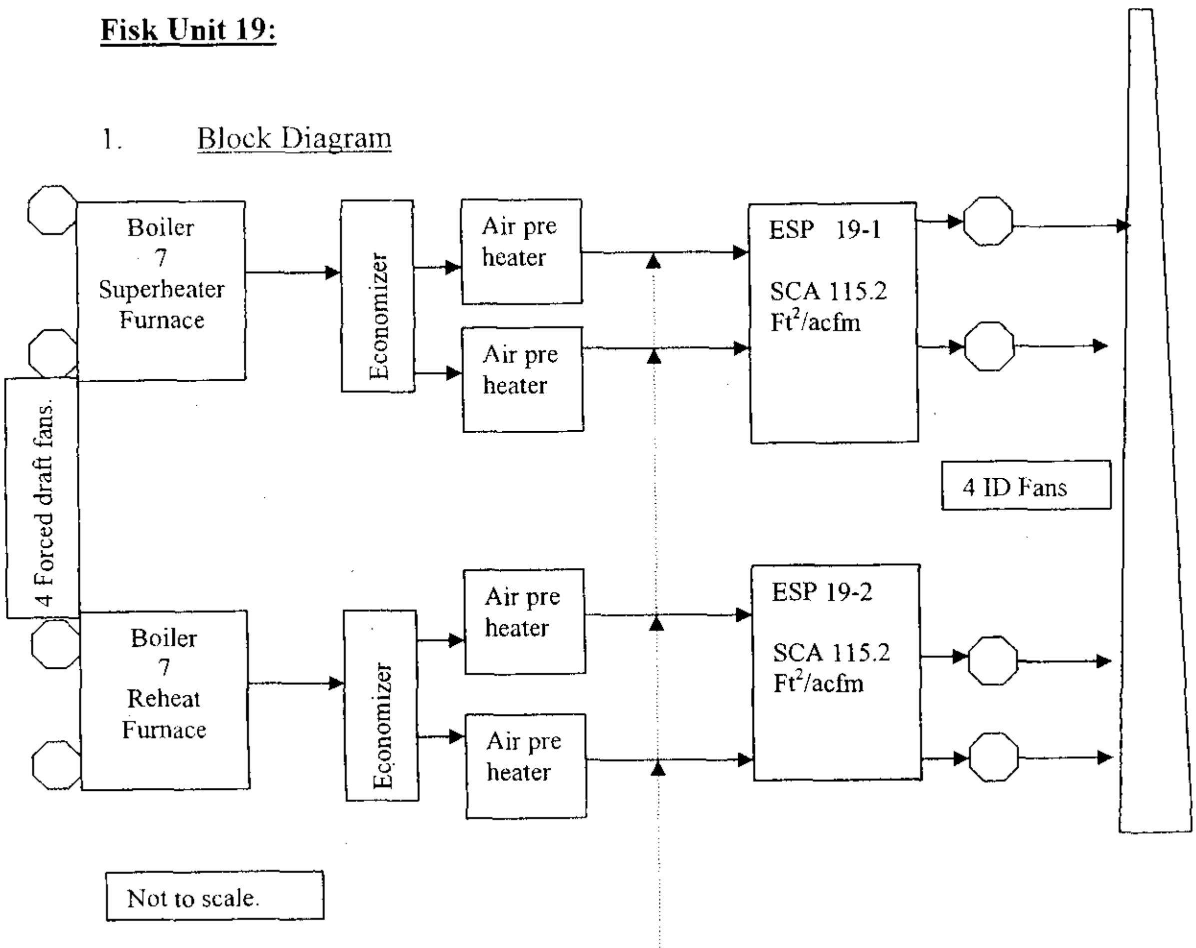
TABLE OF CONTENTS

#1 – Midwest Generation (Fisk)

Source: Midwest Generation, LLC; Fisk Generating Station
I.D. #: 031600 AMI
Address: 1111 W. Cermak Road; Chicago, IL 60608-4594
Contact/Title: Luke Ford/ EH&S Specialist, Bill Shander/Production Manager
Phone/Fax: 312-491-7515
Inspector(s): Joseph Kotas and Emilio Salis

Fisk Unit 19:

1. Block Diagram



The ductwork from the outlet of the four air preheaters to the ESPs is about 40 feet in length total (see page 3.)

2. SO_3 injection

A pilot SO_3 injection project was undertaken in autumn 2004 and abandoned in spring of 2005. Midwest Generation official claimed it had no quantifiable results. Another said it had "mixed results... but they didn't see an impact." The goal of the project was to reduce the resistivity of PRB coal. The pipes and headers were abandoned in place. These are located at the 7^{th} floor at approximately the 116-foot elevation. Gaseous SO_3 was injected at the economizer. The SO_3 generation process was located at ground level.

Fisk also constructed a polymer injection system, which introduced liquid polymer into the ducts after the preheater and upstream of the ESP. The polymer injection system included a header pipe and four spray nozzles installed per duct (16 altogether.) The polymer was supposed to combine with and agglomerate particles in the flue gas to facilitate collection by the ESP. This was done in the time period around 2000. The project was discontinued as the injections accumulated in the ducts producing a series of "stalagmites." The header system and injection ports are still in place.

2. Flue gas conditioning

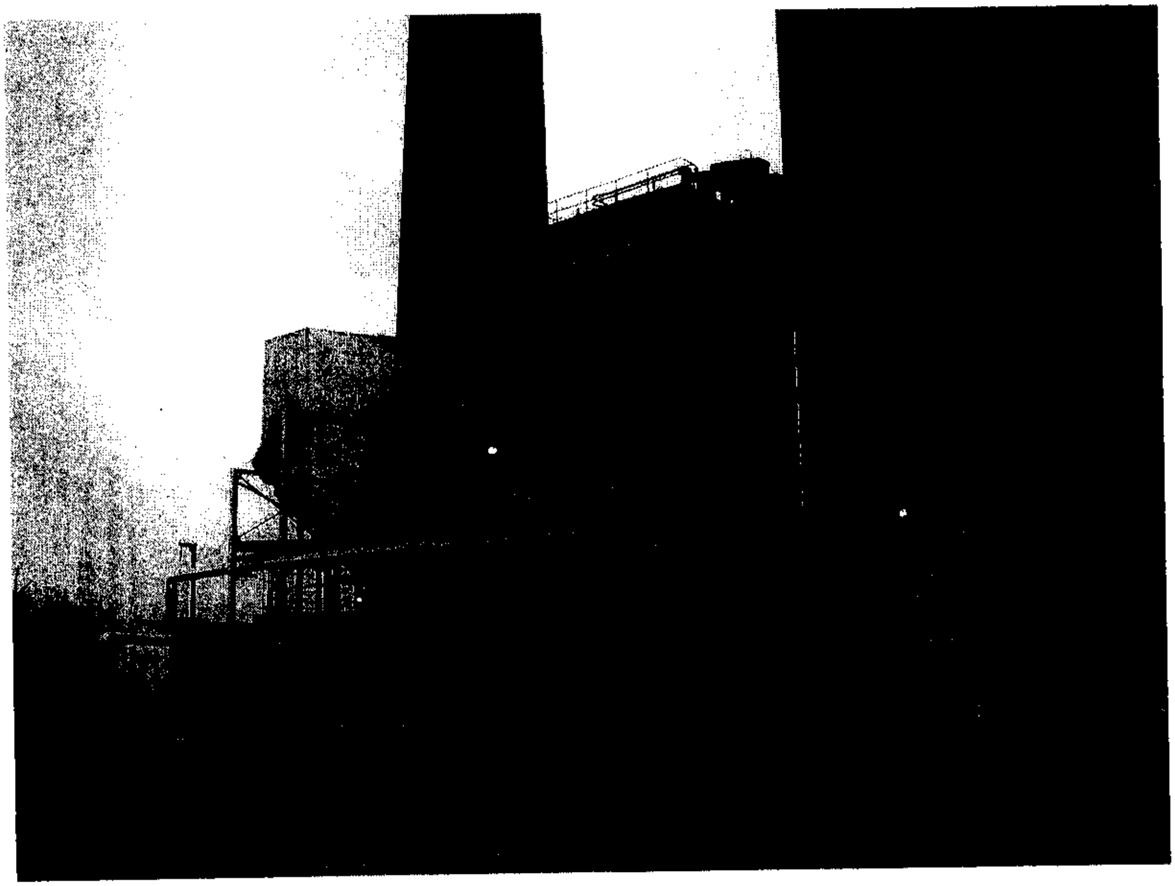
No direct flue gas conditioning is performed. Sodium carbonate, anhydrous is added to the coal at the mine to achieve 3.25-3.75 wt%. The sodium is added to decrease resistivity of the fly ash. Wt % sodium is provided in the quarterly coal analysis reports.

3. Other Information

Fisk Unit 19 is a 3,379 mmBtu/hr electric generating unit consisting of two boilers, a superheater boiler (or "furnace") and a reheat boiler (furnace). This arrangement is known as a "dual furnace." They are basically identical except for the arrangement of tubes in the fireboxes. Each furnace cannot be run separately.

Low sulfur Powder River Basin coal is utilized to achieve sulfur dioxide limits. Unit 19 utilizes low NO_x burners and overfire air for NO_x control.

The ESPs are considered "cold side" since they are located after the preheaters.



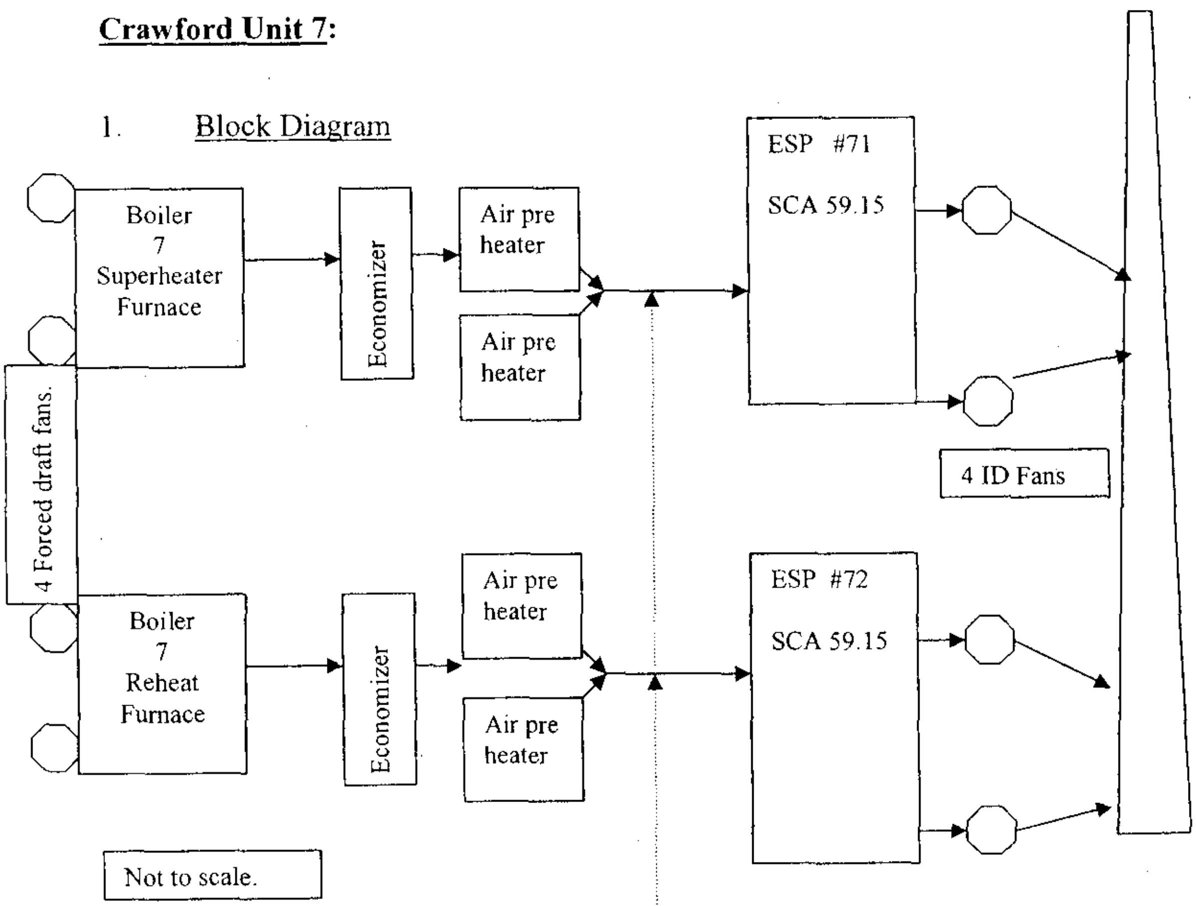
This is a view of the west ESP at Fisk with breeching exiting the ESP and entering the stack. (In the background is the bottom of the Sears tower.) The air preheaters are inside the large building to the right. The preheaters are about 4 feet from the wall at about the same elevation as the ESP. The section of dark transition before the silver ESP pictured and the building is about 25 feet long. It probably houses perforated plates which distribute air into the ESP in a laminar type flow. Total distance of ductwork from exit of preheater to ESP is about 29-35 feet.

#2 – Midwest Generation (Crawford)

Source:	Midwest Generation, LLC; Crawford Generating Station
I.D. #:	031600 AIN
Address:	3501 S. Pulaski Road; Chicago, IL 60623-4987
Contact/Title:	Luke Ford/EH&S Specialist, John Kennedy/Station Director; David Gladem/Production Manager
Phone/Fax:	773-650-5489
Inspector(s):	Joe Kotas and Emilio Salis

Crawford Unit 7:

1. Block Diagram



Looking at each identical furnace separately, two ducts from two air preheaters combine (within 50 feet) to a single duct. The total length runs from the approximately 30-foot elevation to the ESP on the roof at 179-foot elevation. The approximate 150 foot long duct traverses most of this vertical distance as an approximate 32 foot by 7 foot cross section rectangular tube. Each duct, one for the superheater furnace and the other for the reheat furnace enter a 6-7 foot long perforated plate baffle inlet which distributes airflow and into the ESP. Each ESP has two ID fans, which pulls flue gas through the ESPs and exhausts it to the stack. The area around the reheat furnace duct appears to be more accessible than the area around the superheater duct. The restrictions around the superheater duct vary with elevation but there may be accessibility at certain elevations along the 150-foot long span.

2. SO_3 injection

The facility does not use SO_3 injection.

3. Flue gas conditioning

No direct flue gas conditioning is performed. Sodium carbonate, anhydrous is added to the coal at the mine to achieve 3.25-3.75 wt%. The sodium is added to decrease resistivity of the fly ash. Wt % sodium is provided in the quarterly coal analysis reports.

4. Other Information

Crawford Unit 7 is a 216 MW electric generating unit consisting of two boilers, a superheater boiler (or "furnace") and a reheat boiler (furnace). This arrangement is known as a "dual furnace." They are basically identical except for the arrangement of tubes in the fire box. Each furnace cannot be run separately. The superheater furnace supplies high pressure steam to the high pressure turbine, the steam is then routed to the reheat furnace. The turbine on the reheat furnace operates at a lower pressure and utilizes a condenser to extract remaining energy from the steam.

Low sulfur Powder River Basin coal is utilized to achieve sulfur dioxide limits. Unit 7 utilizes low NO_x burners and overfire air for NO_x control.

The ESPs are considered "cold side" since they are located after the preheaters.

ESP collection area is given in what is called "specific collection area," the units of which are ft^2/acfm. The design flow rate (acfm) was not given. The specific collection areas (for units 7 and 8) were taken from stack test reports. Originally the SCA was given as 118.3 and it was suggested by Midwest Generation that to get the individual SCA per ESP to divide the number by two.

A further note about the ducts: There did not appear to be any obvious large open areas near the superheater duct. At low elevations, there is a considerable amount of electrical equipment to the west. At slightly higher elevations, a number of prominent vessels for the feedwater system are placed close to the duct. Then the wall of the building runs adjacent to the duct on the west side of it. On the east side, there is not much room between the down coming duct (hot gas to the air preheater) and the outgoing duct. At one elevation, there did appear to be a large "patch" placed into the side, approximately 25 feet by 6 foot tall section may have been welded into place (see photo.) There is also a steel beam truss section which could support a pad at this approximate 77-foot elevation. We did not see any convenient places in which large equipment (baghouses/ storage silos) could be easily placed. The reheat furnace duct had an adjacent approximately 400 sq foot area open to the East and some windows were within 20 feet east.

ADDENDUM

Date: May 16, 2005
To: Ed Bakowski
From: Joe Kotas

RE: Mercury VIP
SCA CORRECTION

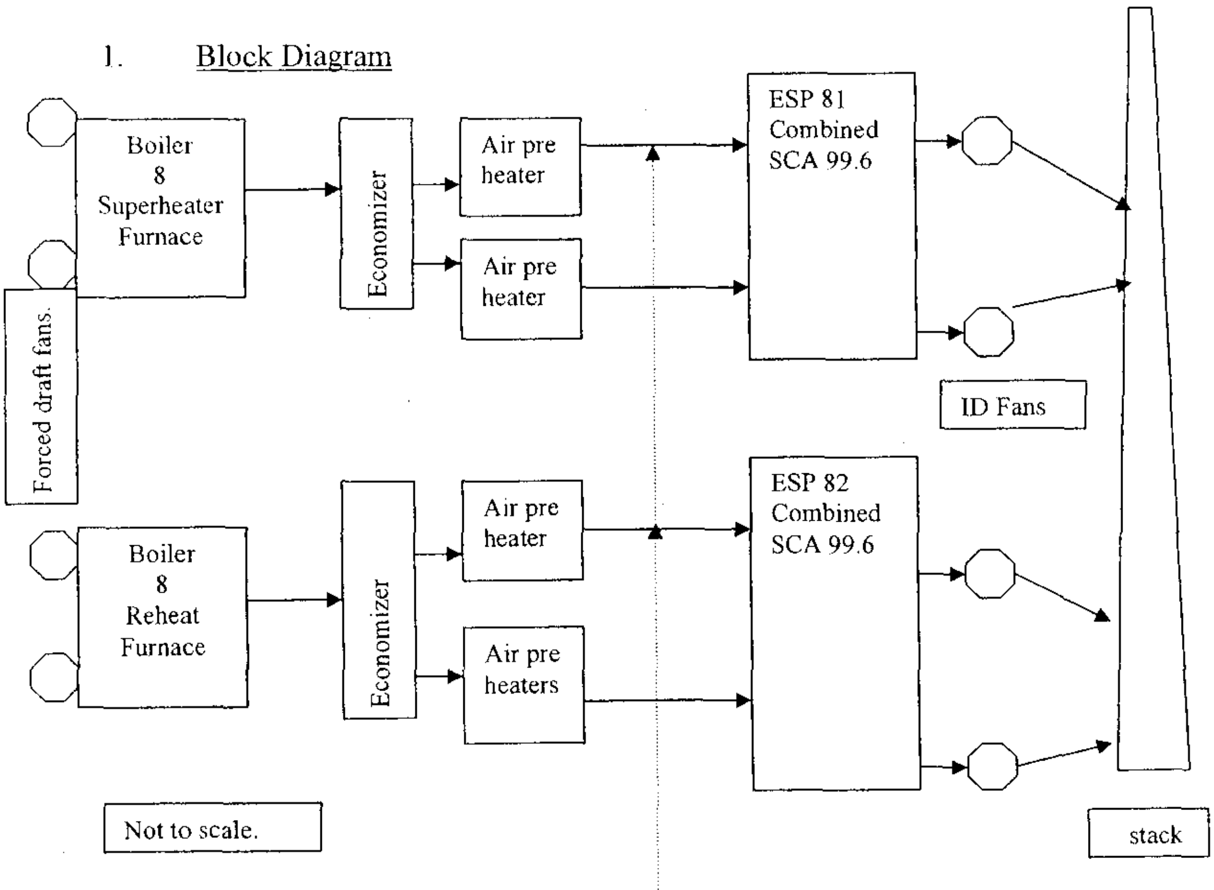
Source:	Midwest Generation, LLC; Crawford Generating Station
I.D. #:	031600 AIN
Address:	3501 S. Pulaski Road; Chicago, IL 60623-4987
Contact/Title:	Luke Ford/EH&S Specialist,John Kennedy/Station Director; David Gladem/Production Manager
Phone/Fax:	773-650-5489
Inspector(s):	Joe Kotas and Emilio Salis

Following an inquiry, further information was gathered concerning the specific collection area ("SCA") of the ESPs at Crawford Unit 7. The SCA for Crawford unit 7 was originally given as 59.15 in the report dated 05/06/06. The correct SCA (as provided by contacts at Midwest Generation) for Crawford Unit #7 is 118.3 $ft^2/kacfm$. Please adjust your records accordingly.

Source: Midwest Generation, LLC; Crawford Generating Station
I.D. #: 031600 AIN
Address: 3501 S. Pulaski Road; Chicago, IL 60623-4987
Contact/Title: Luke Ford/EH&S Specialist, John Kennedy/Station Director; David Gladem/Production Manager
Phone/Fax: 773-650-5489
Inspector(s): Joe Kotas and Emilio Salis

Crawford Unit 8

1. Block Diagram



The unit #8 superheater furnace and the reheat furnaces are basically identical to each other but differ from unit #7 greatly in the configuration of the ductwork from the air preheater to the ESPs. The (four) preheaters (two for each furnace) lie on roughly the same (approximately 50 foot) elevation as the ESPs. (See photo.) The identical four outlet ducts travel 20–25 feet to the four inlet ducts of the ESPs. The total length of the ducts from the air preheaters to the ESPs is about 50 feet. The ESPs are located near the East wall of the power plant building and the flue gases then exhaust outside where the ID fans are located and a 20 foot breeching follows the ESP to the stack at the 41 foot elevation.

The facility does not use SO_3 injection.

3. Flue gas conditioning

No direct flue gas conditioning is performed. Sodium is added at the mine as stated above (which is true for all Midwest Generation plants in the Chicago area.)

4. Other Information

Crawford Unit 8 is a nominal 326 MW electrical generating unit consisting of a dual furnace arrangement connected to a single stack.

Low sulfur Powder River Basin coal is utilized to achieve sulfur dioxide limits. Unit 8 utilizes low NO_x burners and overfire air for NO_x control.

The ESPs are considered "cold side" since they are located after the preheaters.

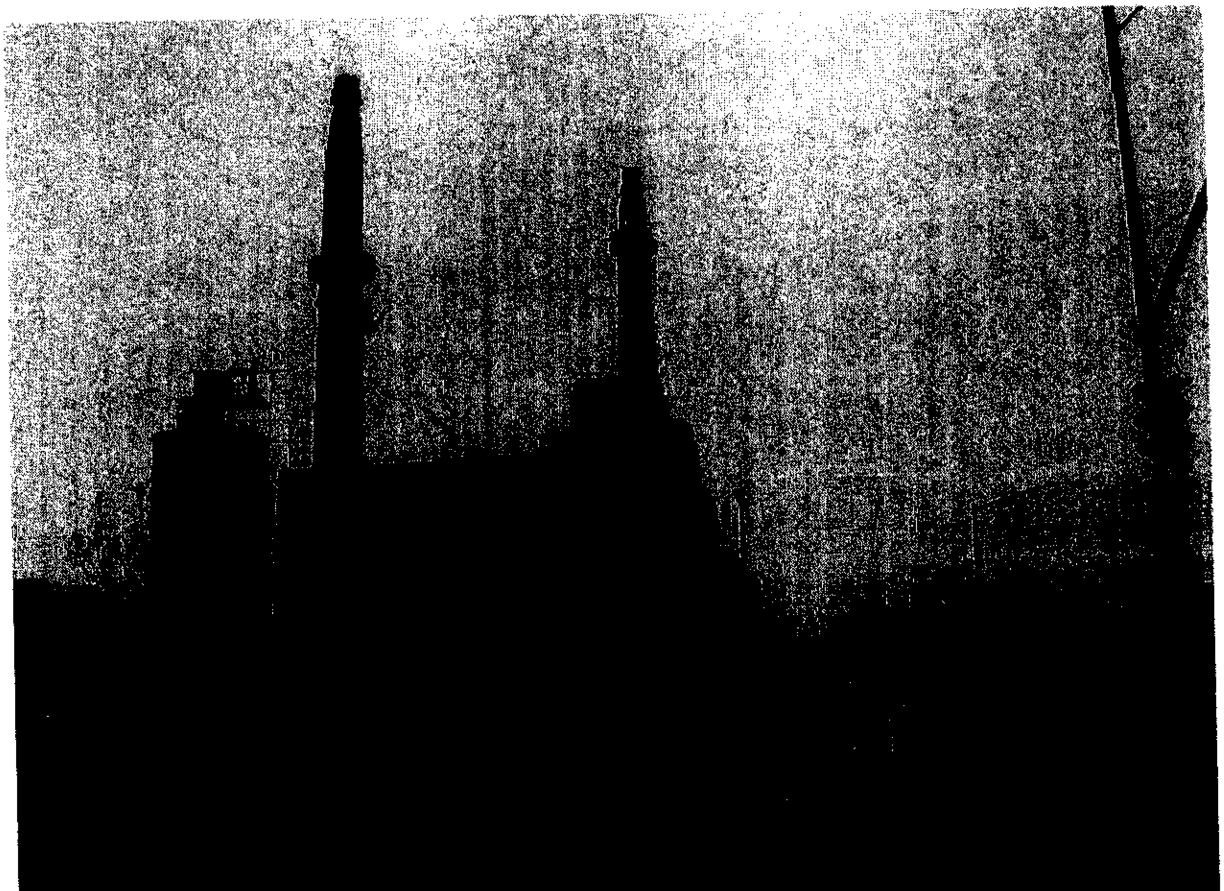
The preheaters are of a "Ljungstrom" design. They consist of cylindrical metal drums with fins. The axis of rotation is between the inlet (cold) and outlet (hot) air streams. The unit rotates to allow the preheated fins to come in contact with the incoming combustion air. The temperature of the flue gas is 600-700 degrees F entering the preheater and 300 degrees F out.

5. Attachments

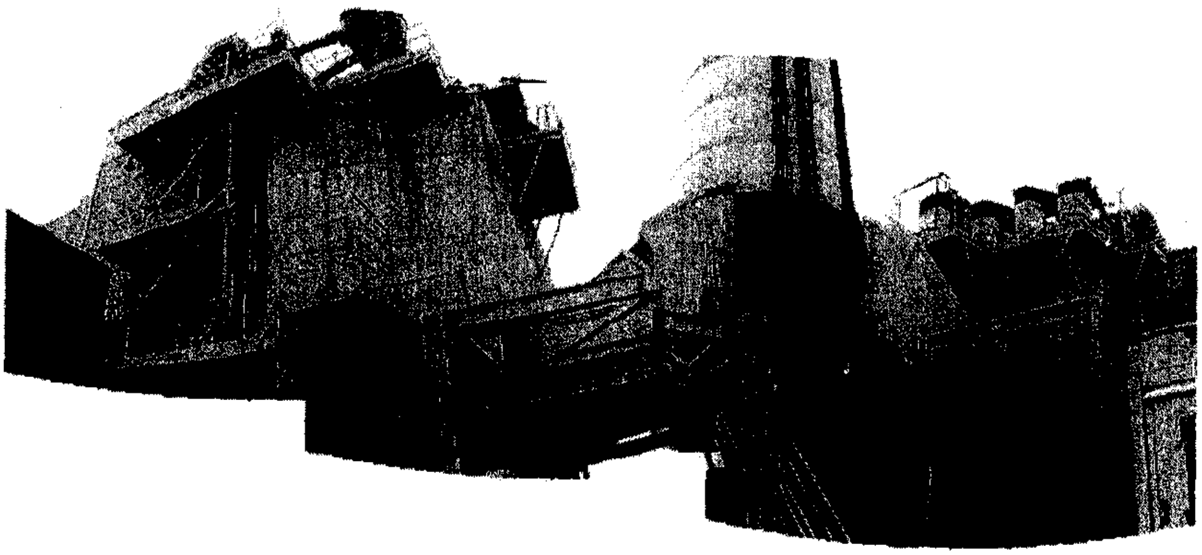
   a. Photos. (Midwest Generation Crawford Generating Station photos)

   b. Side view schematic Crawford 7. (Crawford block)

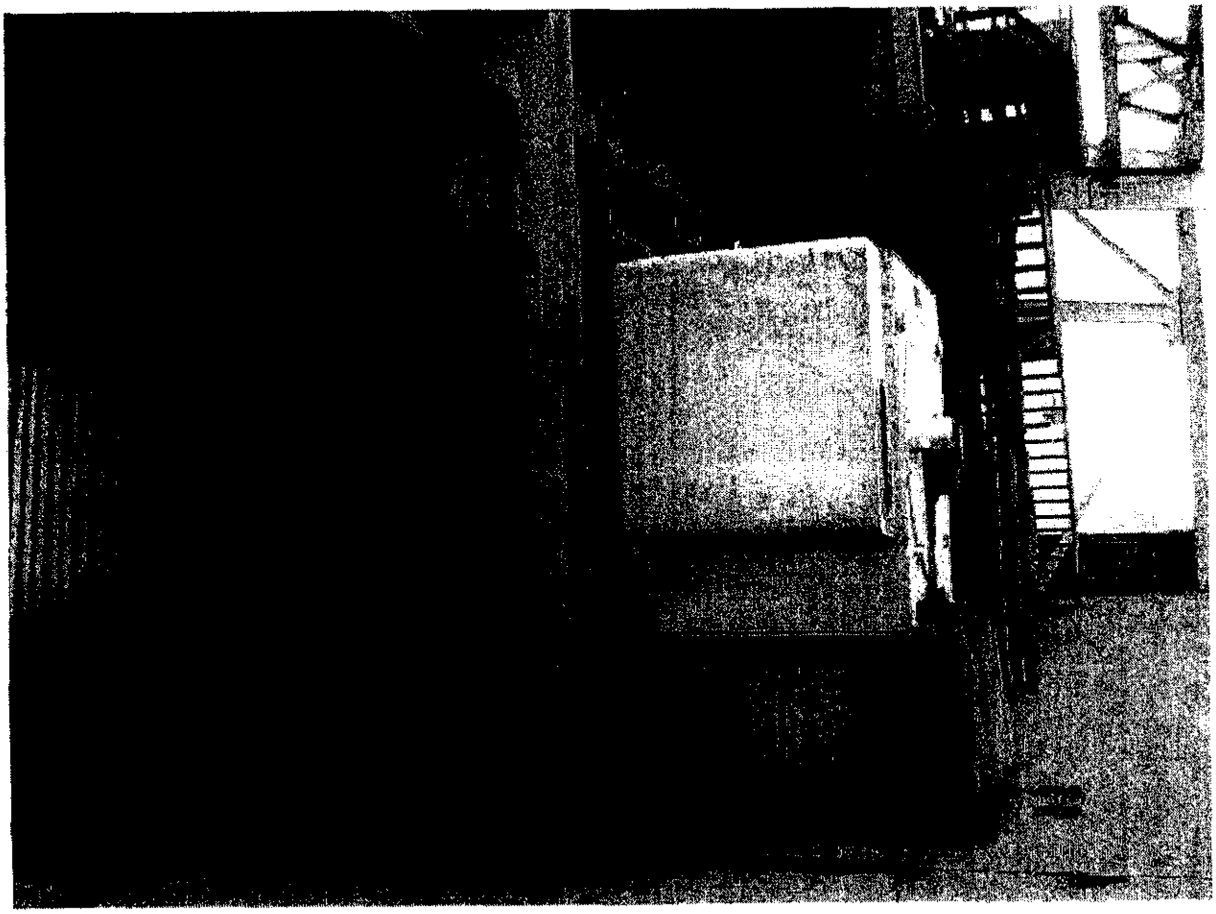
Midwest Generation Crawford Generating Station
031 600 AIN
05/01/06
Photos by J.Kotas



View of Crawford power plant looking south. Unit 7 has two electrostatic precipitators (ESPs) on the roof and an orange and white striped stack. The unit 8 stack is in the foreground.

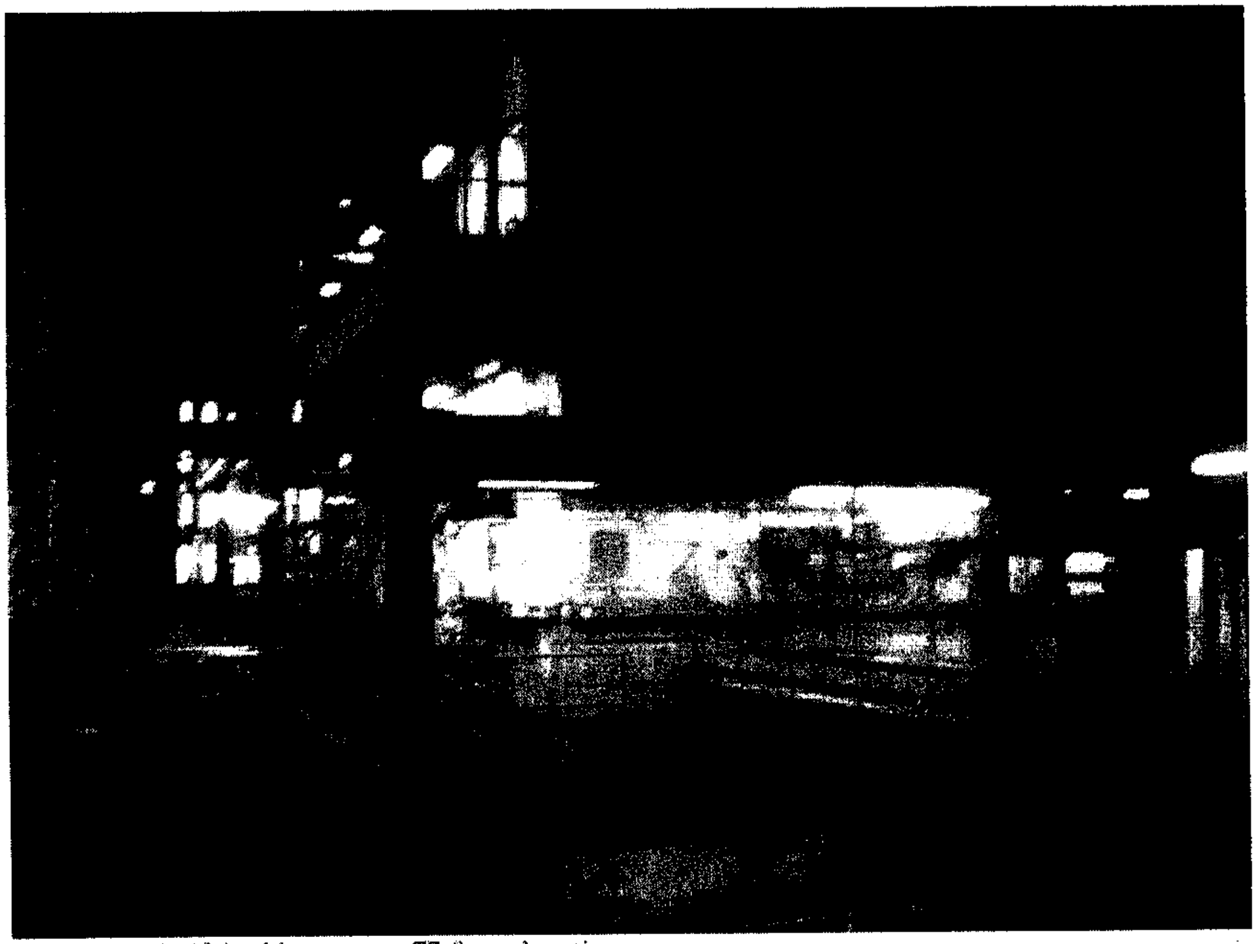


Two ESPs for unit #7 with stack on roof of building.

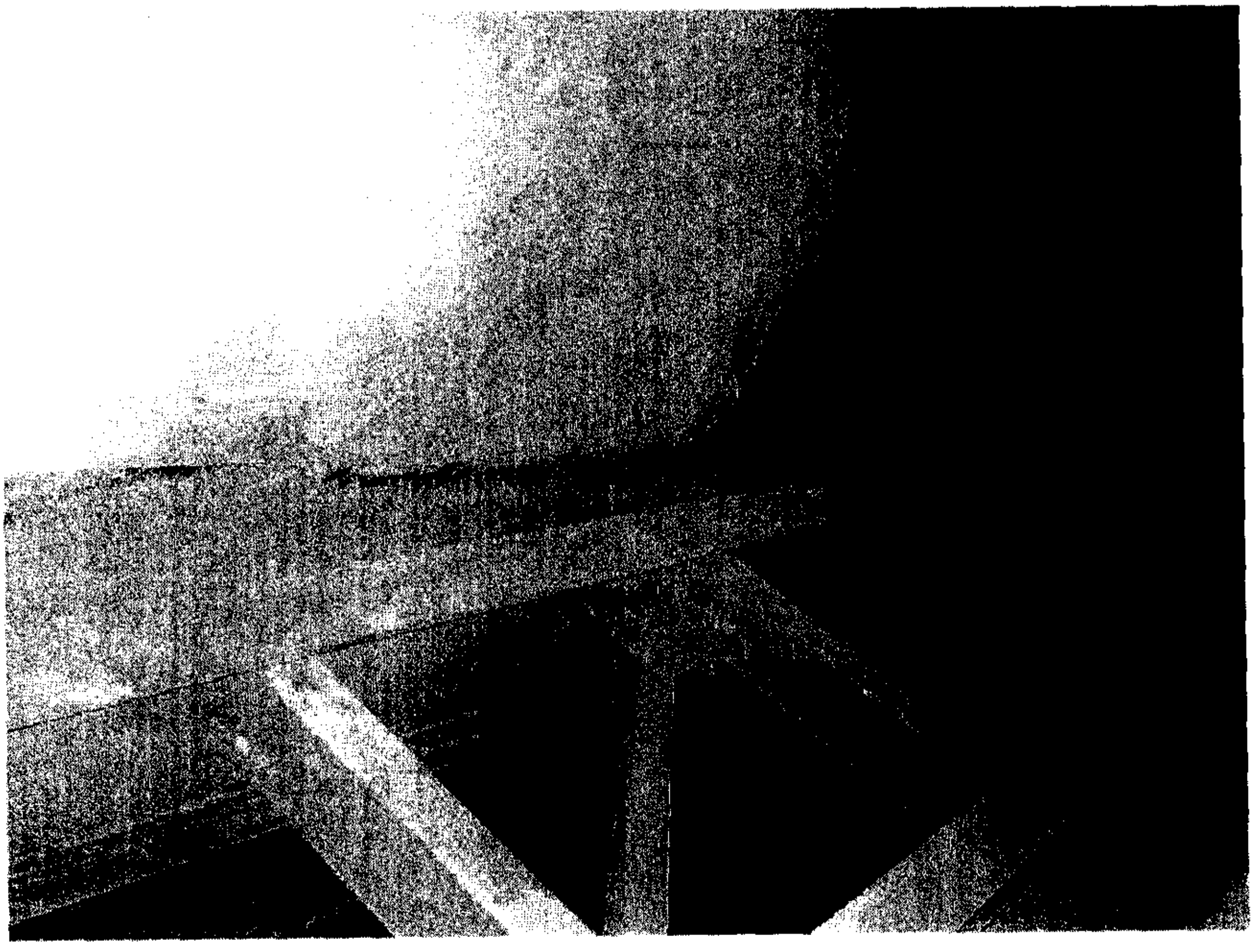


One of two ID fans on NE Reheat precipitator.

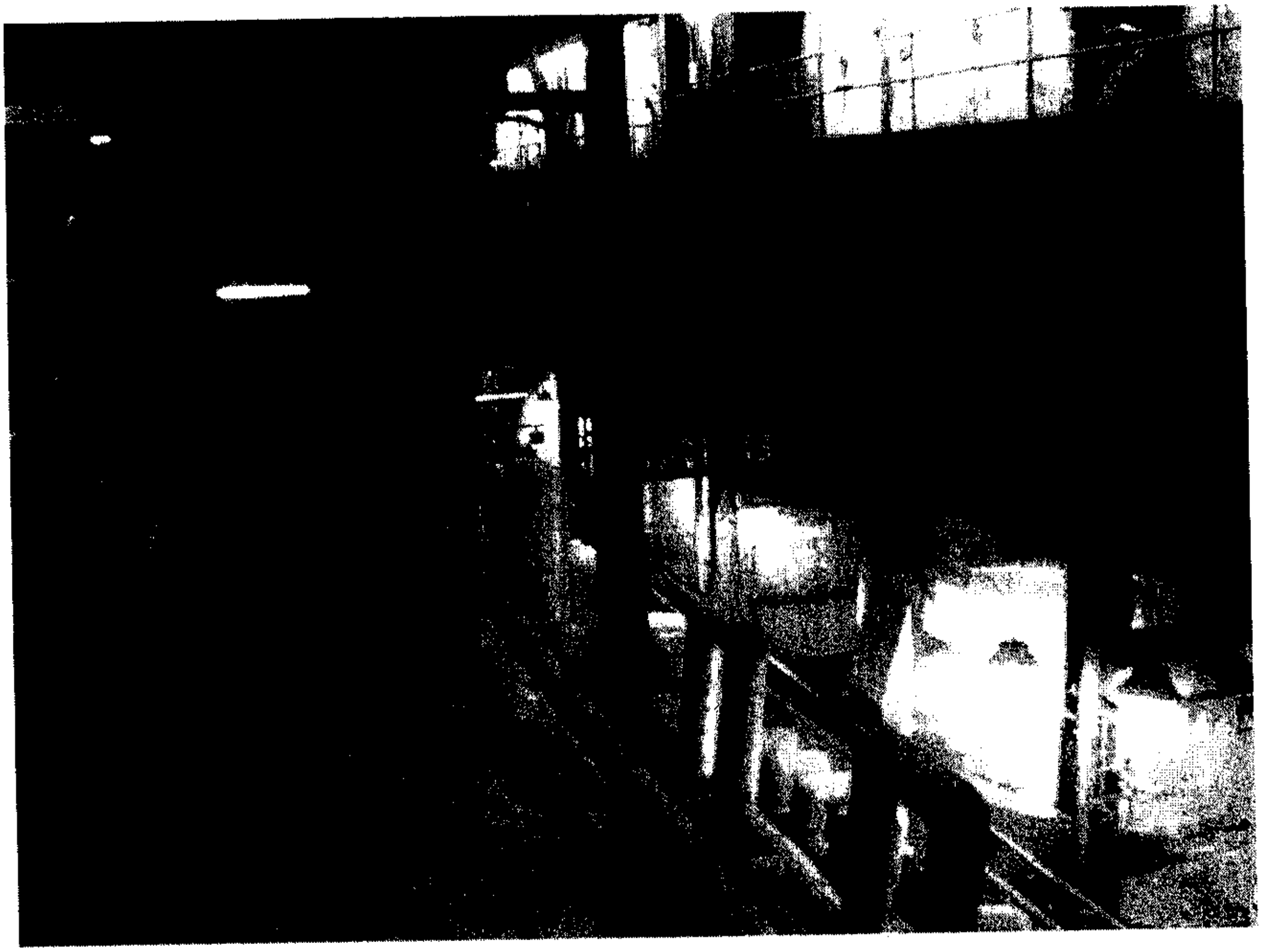
View from roof looking NE at unit 8 breeching to stack. The East ID fan (white) can be seen at base of breeching (right center.). The associated ESPs are inside the covered area.



View of unit #8 looking east at 77 foot elevation.



The steel truss runs horizontal along the ground in this view. The patched duct runs vertically. (Looking south.) This is part of the 7' x 32' duct running from the air preheater to the roof.



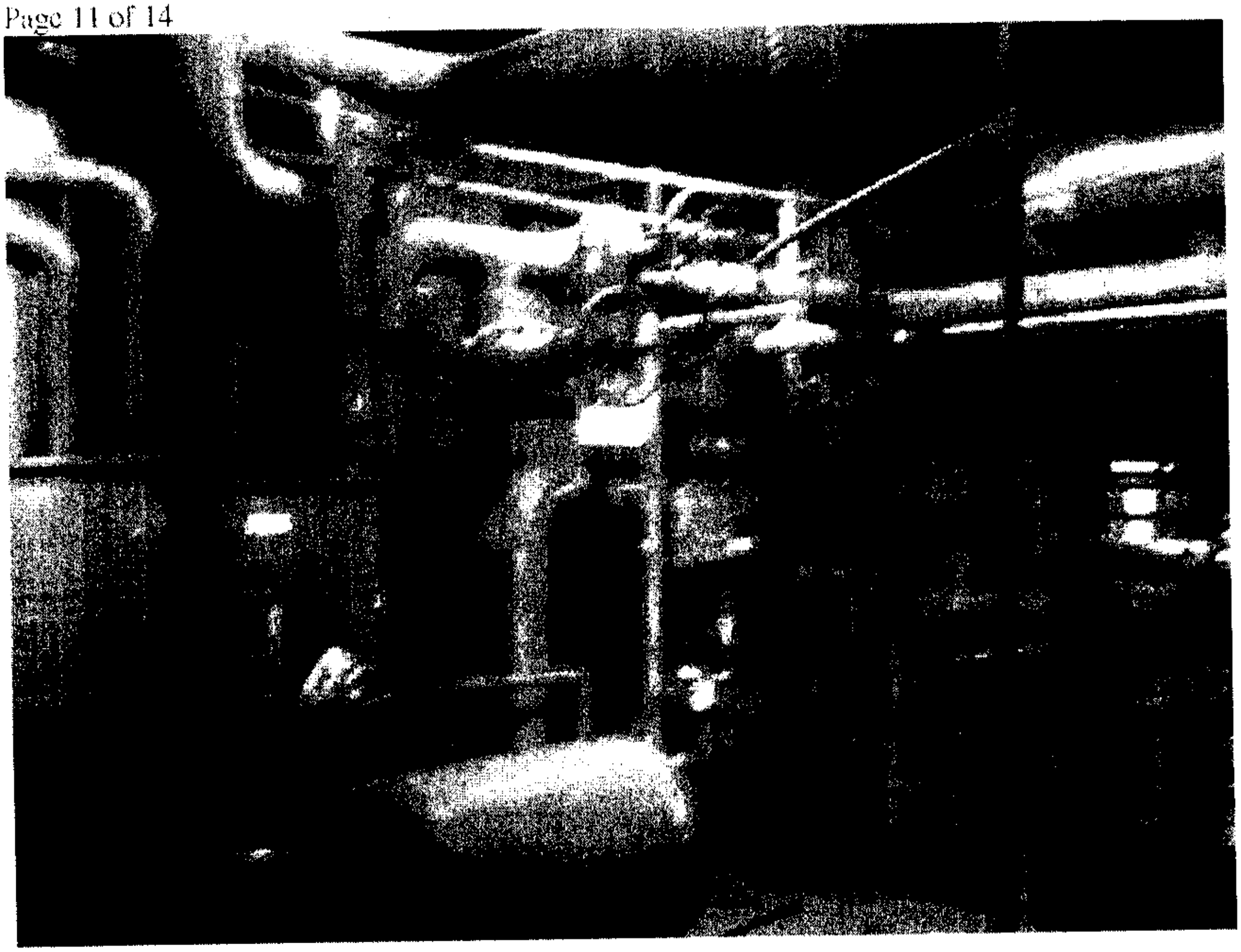
Overview of #8 ESP/preheater arrangement looking east. Note the circular preheaters are on the right. The ductwork exits below them and runs to the left which are the ESPs. The insulated pipes in the center were said to be for the soot blowing system.

Looking up at the reheat duct.

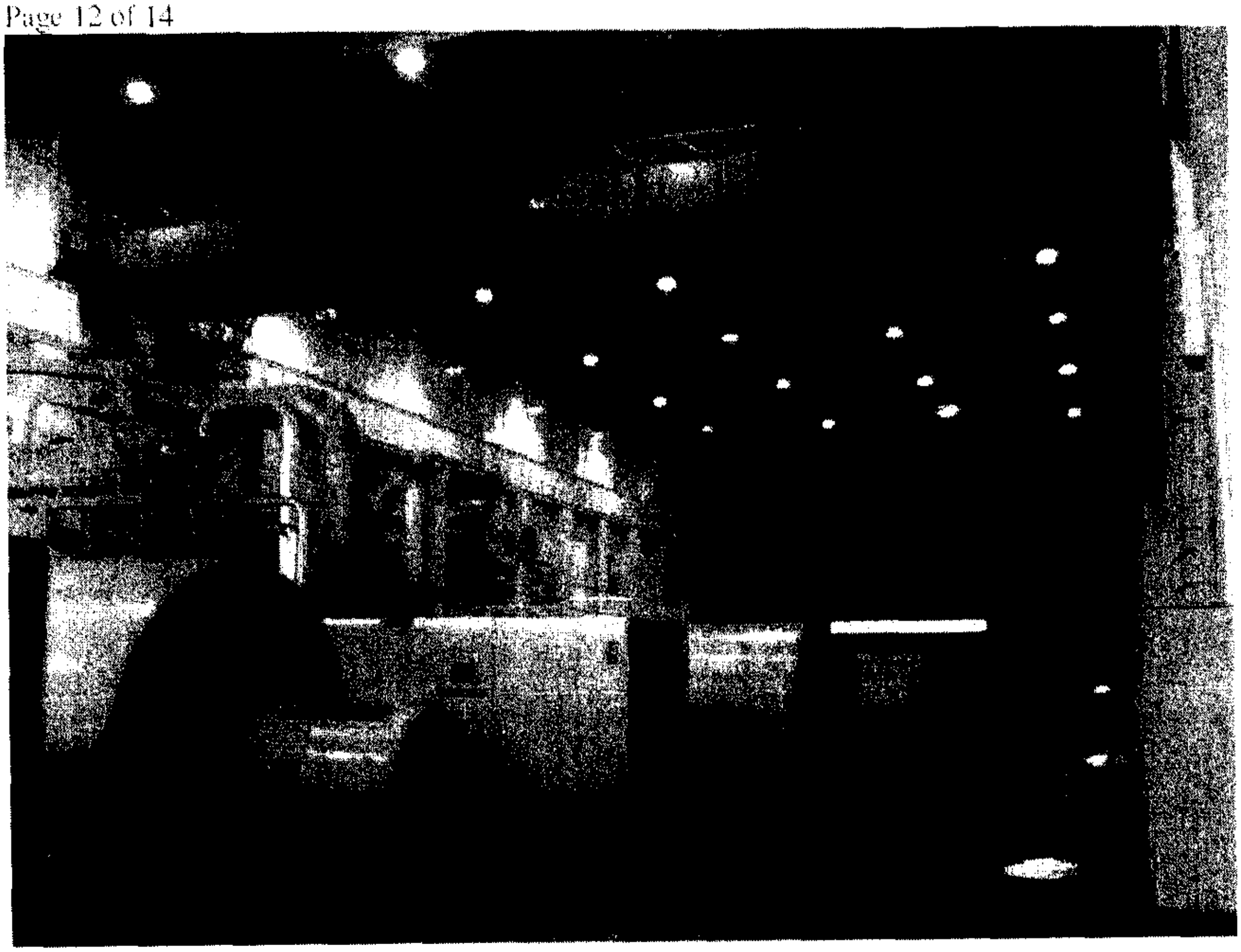
Midwest Generation, LLC; Crawford Generating Station
031600 AIN
05/01/06 Photos by J.Kotas

View of corner of the unit 7 reheat economizer, a large rectangular, insulation covered vessel. Elevation 71 feet.

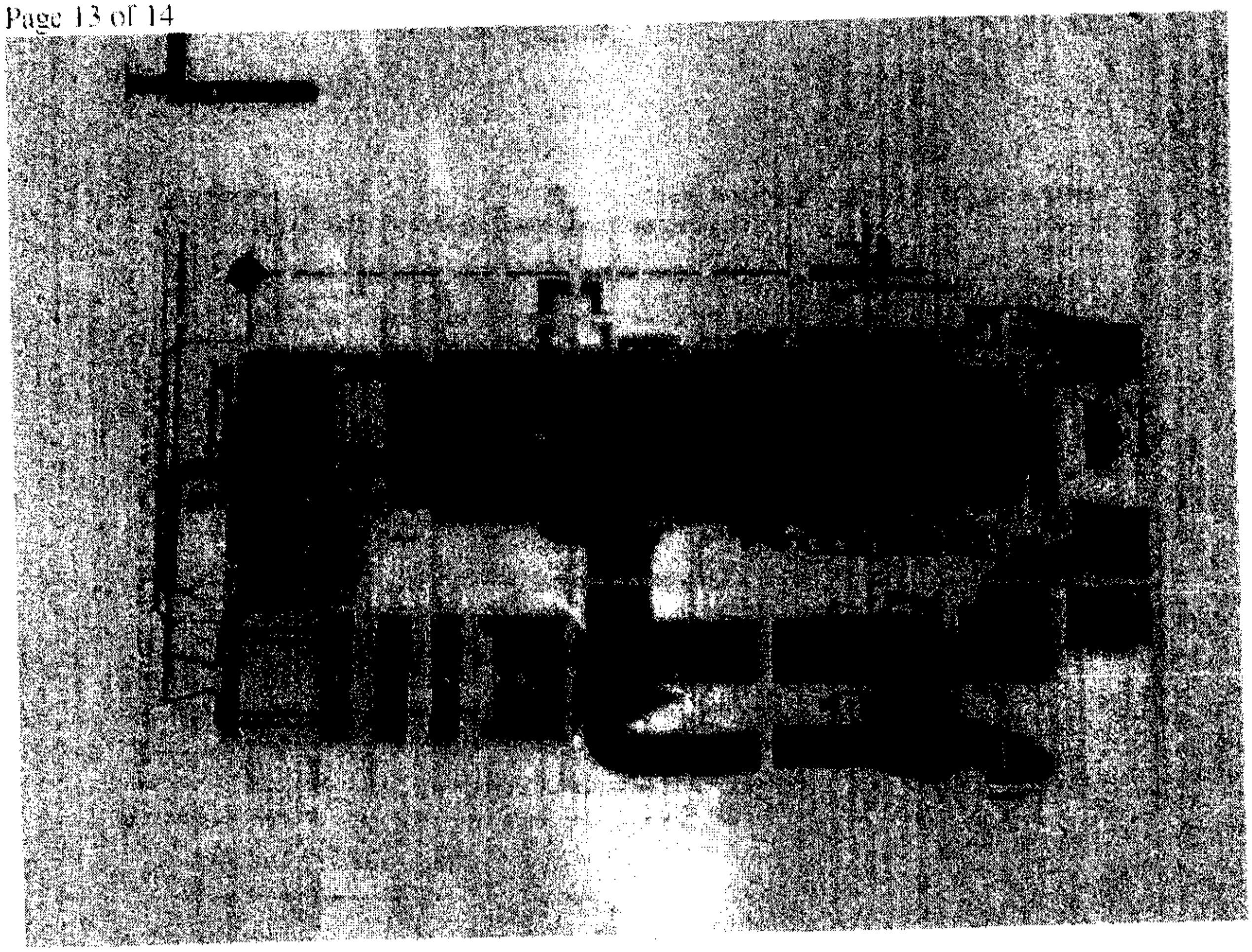
Open area to noth of reheat duct. Elevation approximately 70 feet.



Feedwater systems near #7 superheater duct near ground level.

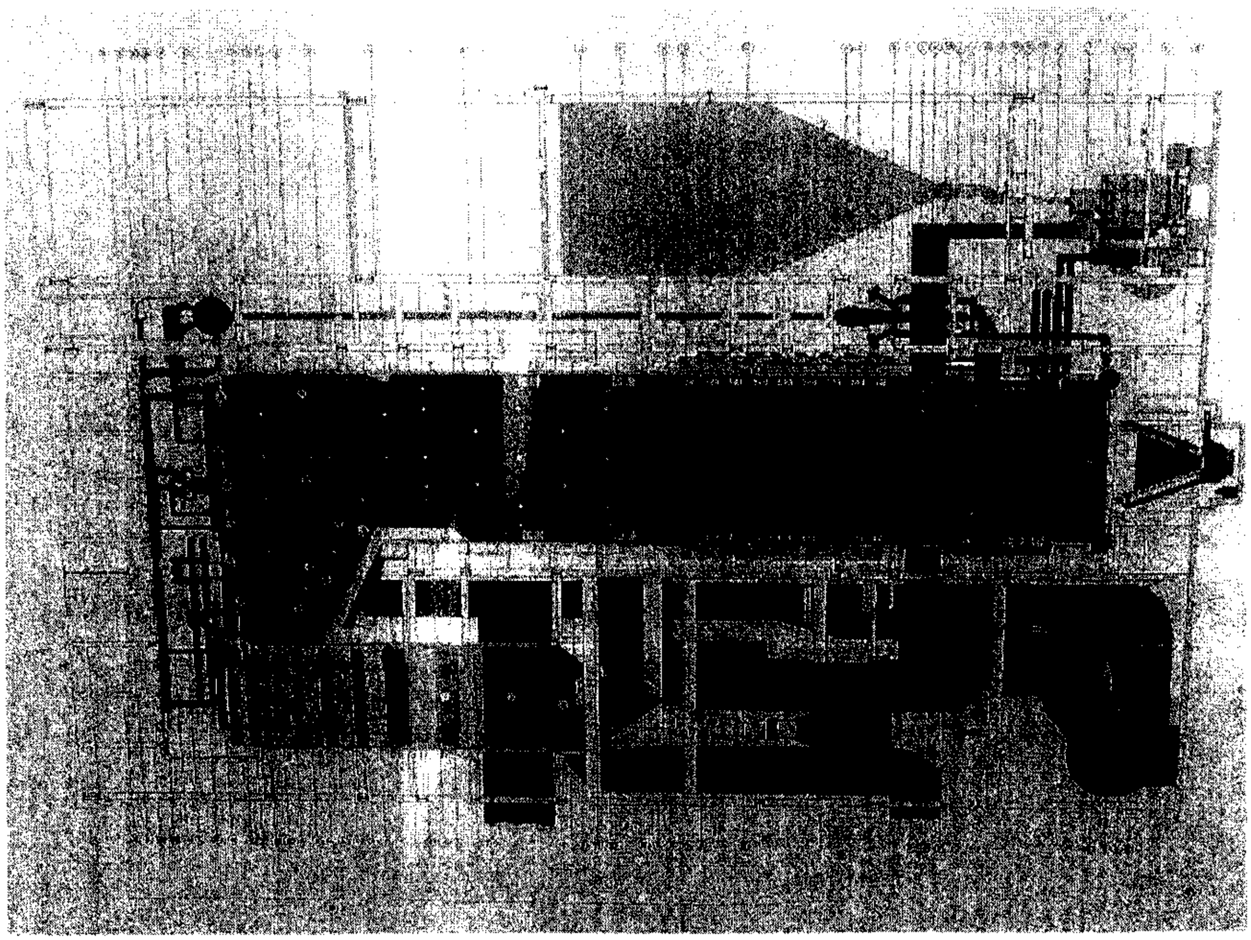


Turbine room. Ground level.



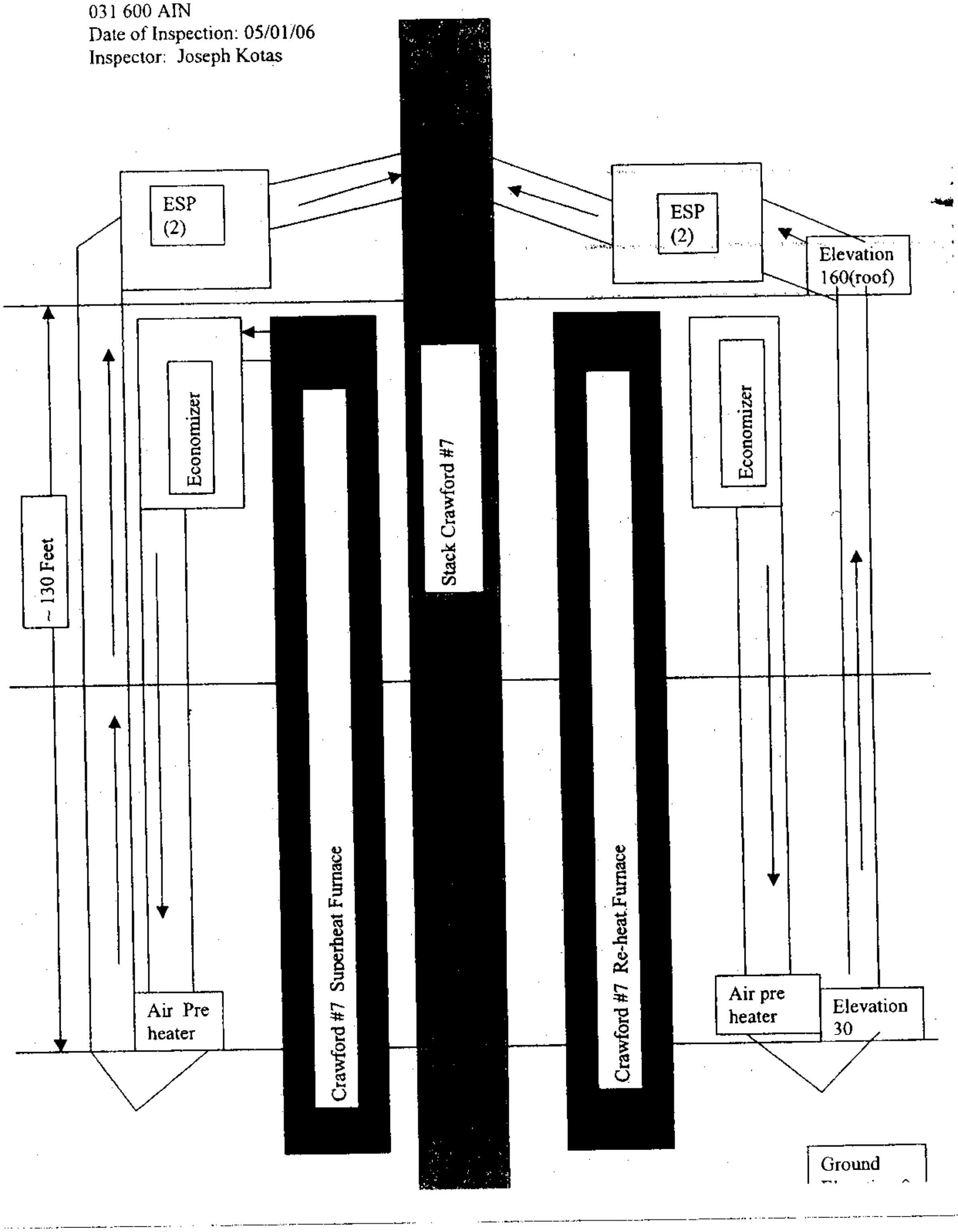
Boiler schematic unit 7.

Midwest Generation, LLC: Crawford Generating Station
031600AIN
05/01/06 Photos by J.Kotas
Page 14 of 14



boiler schematic Unit 8 (better focus).

Midwest Generation Crawford Station/Flue gas schematic Unit #7
031 600 AIN
Date of Inspection: 05/01/06
Inspector: Joseph Kotas

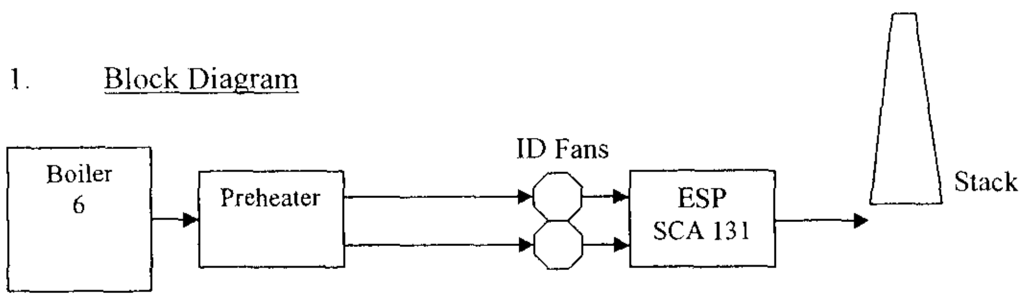


3 – Midwest Generation (Waukegan)

Source:	Waukegan Generating Station
I.D. #:	097190AAC
Address:	401 East Greenwood Avenue
Contact/Title:	Mark Nagel/Engineering Manager, Scott Miller/Senior Environmental Engineer, Mary Connor/EH&S Specialist
Phone/Fax:	847-599-2289
Inspector(s):	George Ordija and Terry Samnadda

Unit 6

1. Block Diagram



The preheater inlet is connected directly to the economizer outlet. The preheater outlet splits to two rectangular ducts with approximate dimensions of 20 feet by 40 feet each. The ducts rise vertically from floor level two to floor level six for a length of approximately 100 feet. The ducts connect to separate ID fans located at the base of the ESP. The outlet of each ID fan splits to two rectangular ducts, which fan out before connecting to two parallel ESPs. The linear distance of the ductwork from the ID fans to the ESPs is approximately 15 feet.

2. SO3 injection

The facility does not use SO3 injection.

3. Flue gas conditioning

No other flue gas conditioning is utilized.

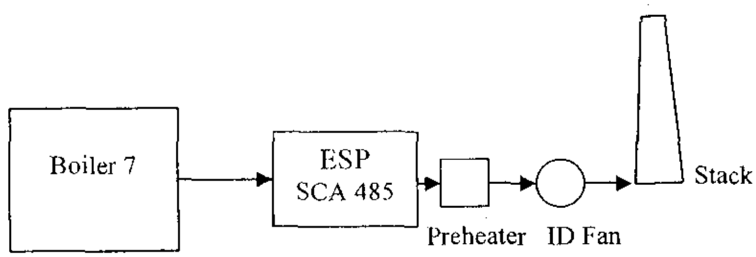
4. Other Information

Low sulfur coal is utilized. All boilers incorporate low NOx technology and over fired air. Start up of the low NOx burners began in April 2002.

Source: Waukegan Generating Station
I.D. #: 097190AAC
Address: 401 East Greenwood Avenue
Contact/Title: Mark Nagel/Engineering Manager, Scott Miller/Senior Environmental Engineer, Mary Connor/EH&S Specialist
Phone/Fax: 847-599-2289
Inspector(s): George Ordija and Terry Samnadda

Unit 7

1. Block Diagram



The economizer outlet exits horizontally approximately 10 feet before the wall of the boiler building. The economizer outlet splits to four rectangular ducts, which then traverse horizontally through the wall for approximately another 10 feet and then turn either vertically upwards (two center ducts) or diagonally upwards (two outer ducts) for approximately an additional 30 feet before connecting to the inlet side of the ESP. As the ducts leave the boiler building, they fan out horizontally and vertically before connecting to two parallel ESPs. The ducts vertical dimensions are approximately 6 feet. The ducts horizontal dimensions could not be determined. However, the horizontal length between the outside walls of the two ESPs is approximately 90 feet. The preheater is on the outlet side of the ESP just before four parallel ID fans.

2. SO3 injection

The facility does not use SO3 injection.

3. Flue gas conditioning

No other flue gas conditioning is utilized.

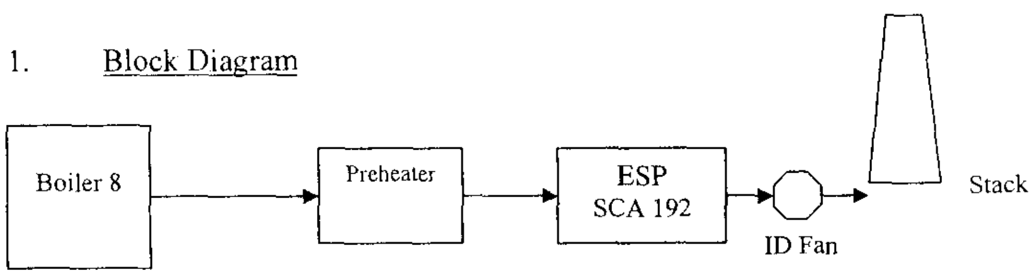
4. Other Information

Low sulfur coal is utilized. All boilers incorporate low NOx technology and over fired air. Start up of the low NOx burners began in April 2002.

Source: Waukegan Generating Station
I.D. #: 097190AAC
Address: 401 East Greenwood Avenue
Contact/Title: Mark Nagel/Engineering Manager, Scott Miller/Senior Environmental Engineer, Mary Connor/EH&S Specialist
Phone/Fax: 847-599-2289
Inspector(s): George Ordija and Terry Samnadda

Unit 8

1. Block Diagram



The economizer outlet ends vertically approximately 75 feet above the inlet to the preheater. A rectangular duct then traverses down from the economizer outlet to the preheater inlet. The preheater outlet exits horizontally just before the wall of the boiler building. The preheater outlet splits to two rectangular ducts. The ducts fan out horizontally through the wall for an additional 15 feet and then fan out diagonally upwards for an additional 20 feet before connecting to two parallel ESPs. The ducts vertical dimensions are approximately 6 feet. The ducts horizontal dimensions could not be determined. However, the horizontal length between the outside walls of the two ESPs is approximately 80 feet.

2. SO3 injection

The facility does not use SO3 injection.

3. Flue gas conditioning

No other flue gas conditioning is utilized.

4. Other Information

Low sulfur coal is utilized. All boilers incorporate low NOx technology and over fired air. Start up of the low NOx burners began in April 2002.

#4 – Midwest Generation (Powerton)

TIER I INSPECTION MEMORANDUM

Date May 02, 2006 Date of Inspection: May 02, 2006

To: E. Bakowski

From: R.Syed I.D. #: 179801AAA R/D 202

Source: Midwest Generation, LLC

Address: 13082 East Manito Road, Pekin 61554

Contact/Title: Joseph A. Heredia/Environmental

Phone: 309-477-5289/309-477-5268

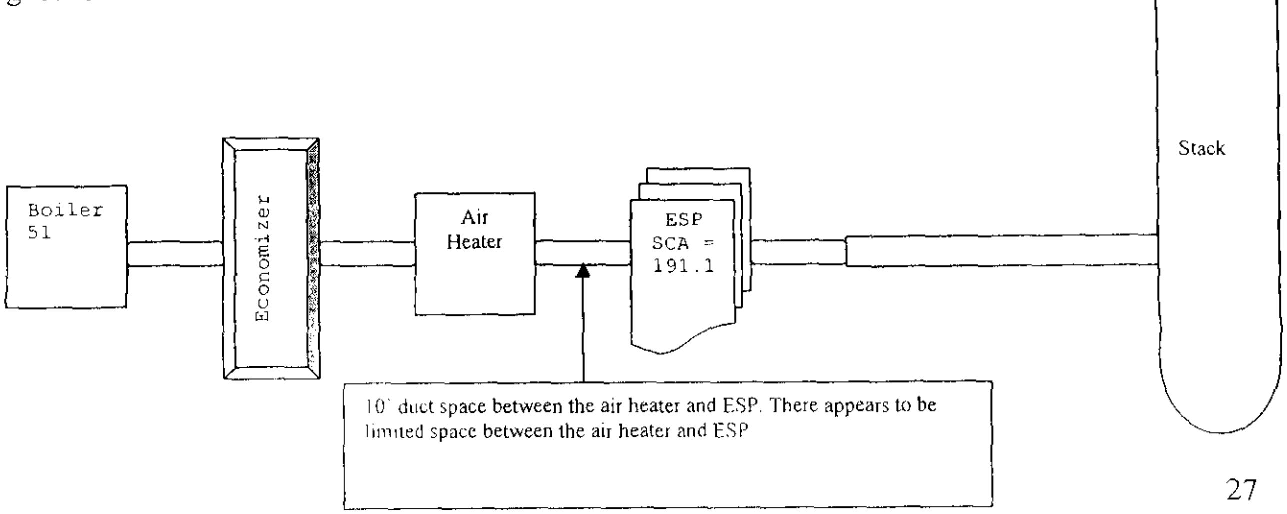
Inspector(s): Rizwan Syed/Wayne Kahila

Purpose: Coal-fired power plant equipment verification/clarification

1. BLOCK DIAGRAM

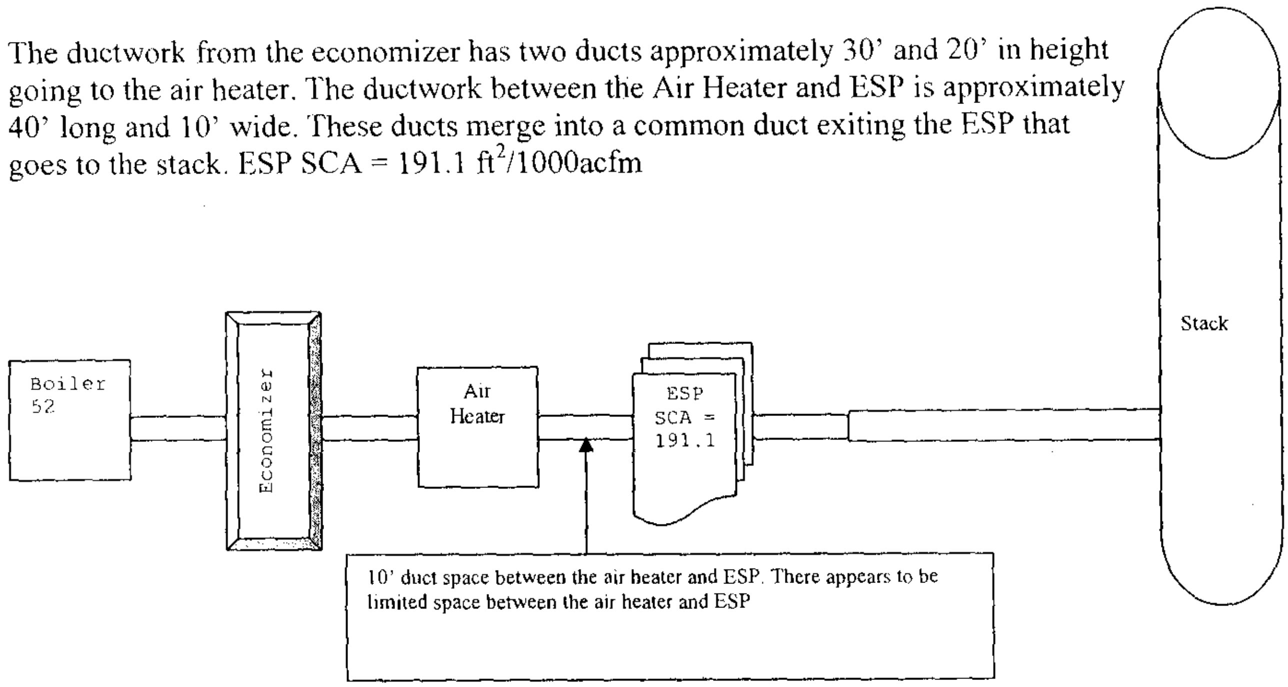
Boiler 51

The ductwork from the economizer has two ducts approximately 30' and 20' in height going to the air heater. The ductwork between the Air Heater and ESP is approximately 40' long and 10' wide. These ducts merge into a common duct exiting the ESP that goes to the stack. ESP SCA = 191.1 ft^2/1000acfm



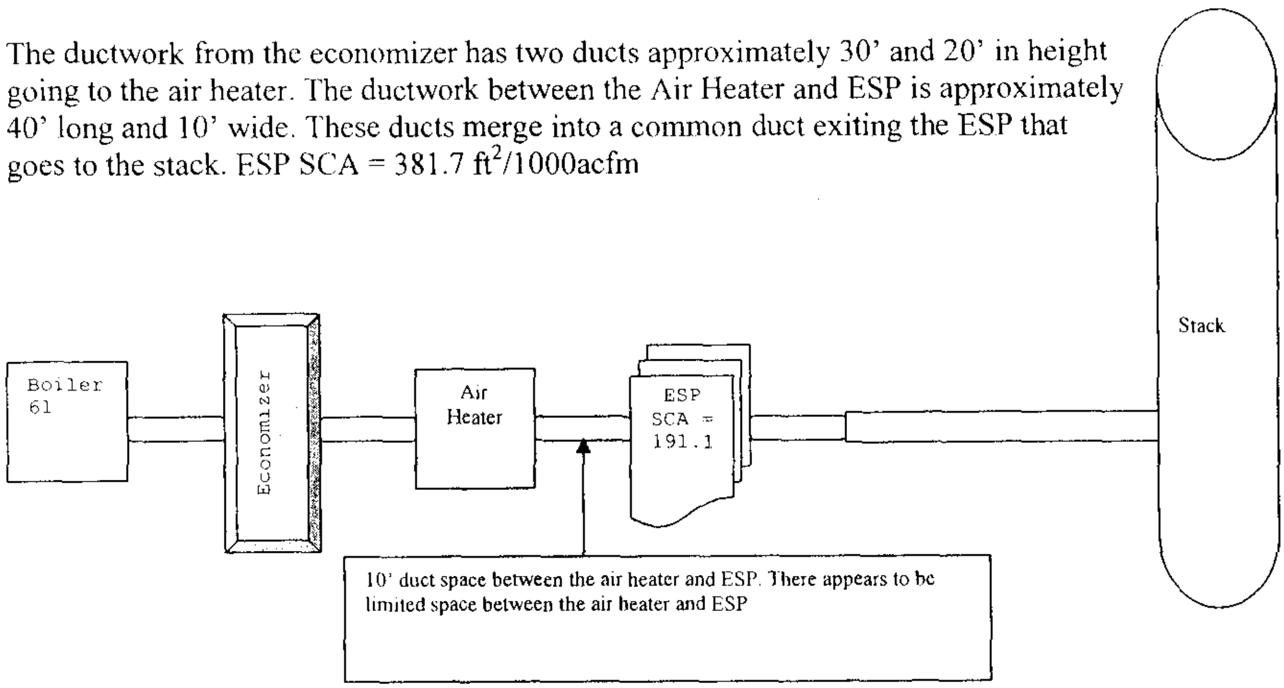
Boiler 52

The ductwork from the economizer has two ducts approximately 30' and 20' in height going to the air heater. The ductwork between the Air Heater and ESP is approximately 40' long and 10' wide. These ducts merge into a common duct exiting the ESP that goes to the stack. ESP SCA = 191.1 ft^2/1000acfm



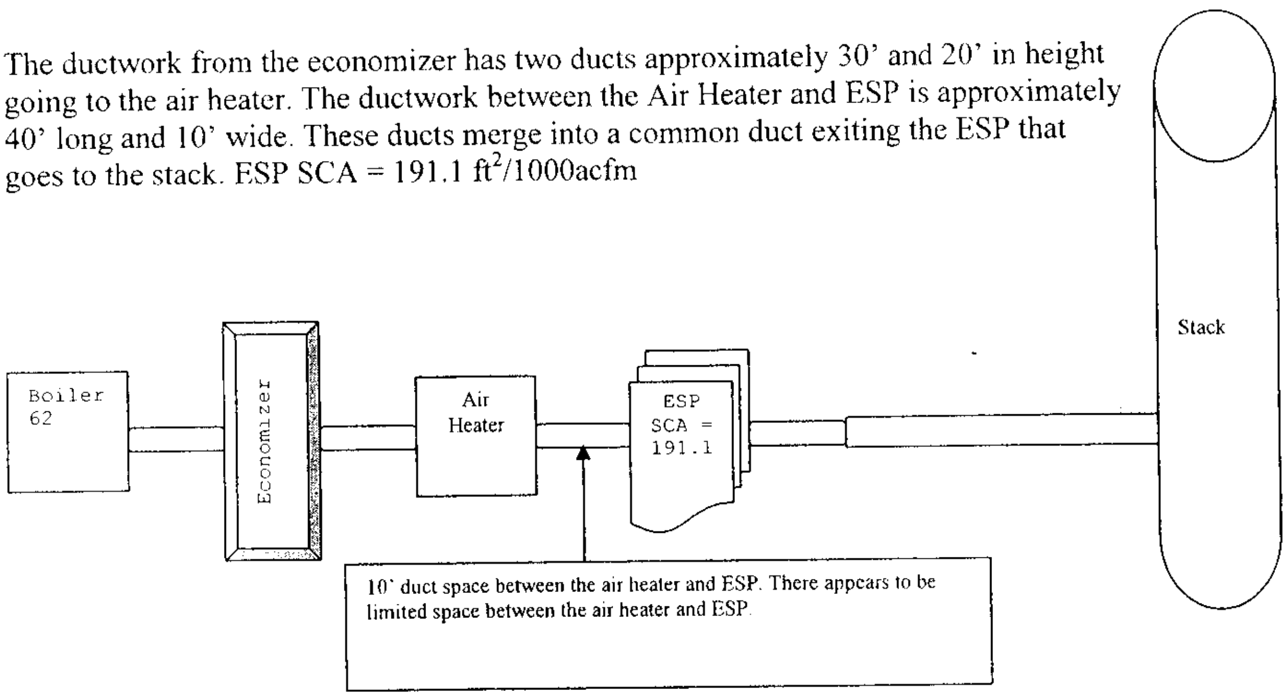
Boiler 61

The ductwork from the economizer has two ducts approximately 30' and 20' in height going to the air heater. The ductwork between the Air Heater and ESP is approximately 40' long and 10' wide. These ducts merge into a common duct exiting the ESP that goes to the stack. ESP SCA = 381.7 ft^2/1000acfm



Boiler 62

The ductwork from the economizer has two ducts approximately 30' and 20' in height going to the air heater. The ductwork between the Air Heater and ESP is approximately 40' long and 10' wide. These ducts merge into a common duct exiting the ESP that goes to the stack. ESP SCA = 191.1 ft^2/1000acfm



2. SO3 injection

The facility does not use SO3 injection in any of the boilers.

3. Flue gas conditioning

No flue gas conditioning is utilized.

4. Other Information

This facility is an electric-powered generating station with two units, 5 and 6, each consisting of two crushed coal-fired boilers controlled by ESP units and a turbine-driven generator. Unit 5 covers boilers number 51 and 52 and Unit 6 covers boilers number 61 and 62. The ductworks for all these boilers are identical. Each boiler has a nominal capacity of 4116 mmBtu/hr each and are served by a single shared stack. NOx emissions are controlled by low-NOx overfire air systems and the PM emissions are controlled by ESP. Generators for units 5 and 6 are permitted for 851 MW and 846 MW, respectively.

Coal is received by rail into a car dumper and coal crushers and then moved by conveyor to the stockpile or surge bins. From the surge bins, coal is fed by a conveyor to the conditioners and then to the silos. All sources, including the fly ash bins; with uncontrolled emission rates greater than the allowable rate are controlled by bag houses. The coal silo for unit 5 also has a wet dust extractor system and there are dry fogger systems on the traveling tripper car and at some tripper room transfer points. Other sources are an auxiliary oil-fired boiler for facility heating and start-up steam for units 5 and 6, several insignificant storage tanks, a gasoline dispensing station, coal storage pile, and roadways.

Emissions Unit Information

Emission Unit	Description	Emission Control Equipment
Unit 5 Boiler BLR 51	Babcock and Wilcox Dual Cyclone fired Nominal 4116 mmBtu/hr (1973)	Low NOx, Overfire Air and ESP
Unit 5 Boiler BLR 52	Babcock and Wilcox Dual Cyclone fired Nominal 4116 mmBtu/hr (1973)	Low NOx, Overfire Air and ESP
Unit 6 Boiler BLR 61	Babcock and Wilcox Dual Cyclone fired Nominal 4116 mmBtu/hr (1976)	Low NOx, Overfire Air and ESP
Unit 6 Boiler BLR 62	Babcock and Wilcox Dual Cyclone fired Nominal 4116 mmBtu/hr (1976)	Low NOx, Overfire Air and ESP

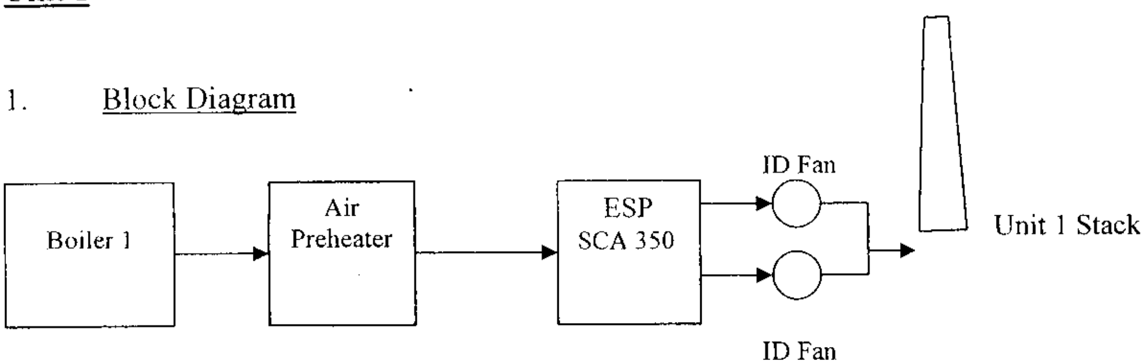
In addition, the facility supplied flow diagram of the boilers operation.

#5 – Midwest Generation (Will County)

Source: Will County Generating Station
I.D. #: 197810AAK
Address: 529 E. 135th Street
Contact/Title: Craig J. Lucke/EH&S Specialist
Phone/Fax: 815-886-1010 Ext. 2289
Inspector(s): George Ordija and Martin Tippin

Unit 1

1. Block Diagram



The preheater is connected directly to the economizer outlet. The preheater outlet splits into two rectangular ducts of 5 feet by 20 feet each. The ducts rise vertically for approximately 15 feet and then make a 90-degree turn and travel horizontally for approximately 70 feet before entering a split ESP plenum. The last 15 to 20 feet of the ductwork is outside of the boiler building.

2. SO3 injection

The facility does not use SO3 injection.

3. Flue gas conditioning

No other flue gas conditioning is utilized.

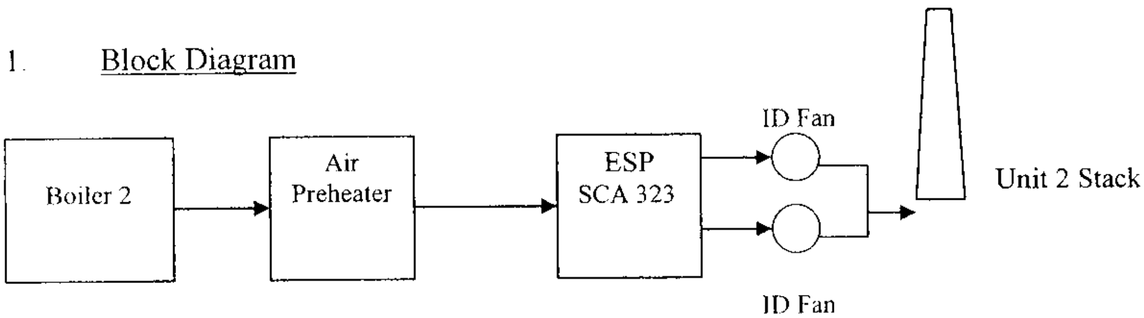
4. Other Information

Low sulfur coal is utilized. All boilers incorporate low NOx technology and over-fired air.

Source: Will County Generating Station
I.D. #: 197810AAK
Address: 529 E. 135th Street
Contact/Title: Craig J. Lucke/EH&S Specialist
Phone/Fax: 815-886-1010 Ext. 2289
Inspector(s): George Ordija and Martin Tippin

Unit 2

1. Block Diagram



The preheater is connected directly to the economizer outlet. The preheater outlet splits into four equal size rectangular ducts. Each duct is approximately 8 feet high by 12 feet wide. The ducts first traverse vertically from the preheater outlet for approximately 6 feet, make a 90-degree turn and then traverse horizontally for approximately 20 feet before entering a split ESP plenum. The first 12 feet of the horizontal ductwork is inside the boiler building. The remaining ductwork is outside.

2. SO3 injection

The facility does not use SO3 injection.

3. Flue gas conditioning

No other flue gas conditioning is utilized.

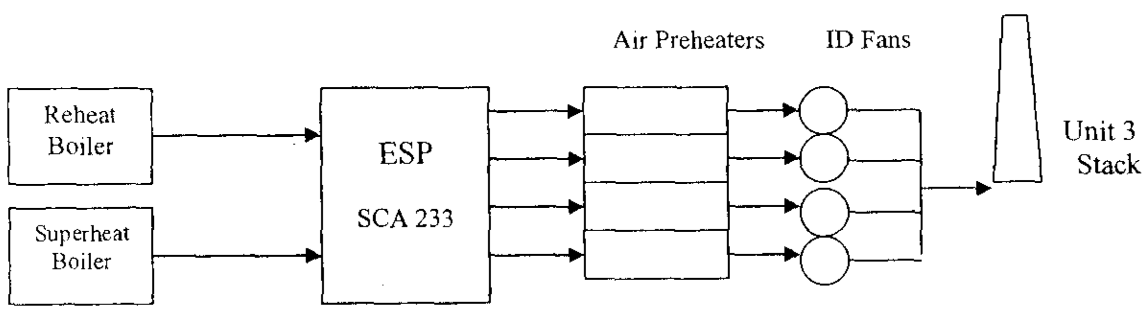
4. Other Information

Low sulfur coal is utilized. All boilers incorporate low NOx technology and over-fired air.

Source:	Will County Generating Station
I.D. #:	197810AAK
Address:	529 E. 135th Street
Contact/Title:	Craig J. Lucke/EH&S Specialist
Phone/Fax:	815-886-1010 Ext. 2289
Inspector(s):	George Ordija and Martin Tippin

Unit 3

1. Block Diagram



Two rectangular ducts, one from the reheat boiler and the other from the superheat boiler come off their respective boilers approximately 6 feet from the wall of the boiler building. Each duct is approximately 6 feet high by 12 feet wide. The ducts traverse horizontally through the wall for an additional 8 feet before entering the ESP plenum. The plenum is split with one side for the reheat boiler and the other side for the superheat boiler. A similar plenum on the outlet side of the ESP splits into four rectangular ducts. The ducts traverse down the ESP, make a 90-degree bend and traverse horizontally back into the boiler building. The horizontal distance back to the boiler building is approximately 50 feet. The ducts traverse through the boiler building wall for an additional 12 feet, make a 90-degree bend downwards and traverse an additional 10 feet before connecting to the inlet of the air preheater.

2. SO3 injection

The facility does not use SO3 injection.

3. Flue gas conditioning

No other flue gas conditioning is utilized.

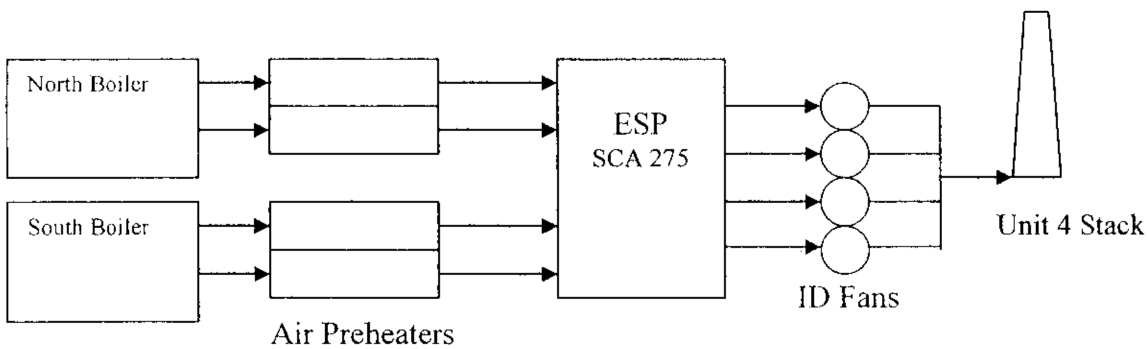
4. Other Information

Low sulfur coal is utilized. All boilers incorporate low NOx technology and over-fired air.

Source: Will County Generating Station
I.D. #: 197810AAK
Address: 529 E. 135th Street
Contact/Title: Craig J. Lucke/EH&S Specialist
Phone/Fax: 815-886-1010 Ext. 2289
Inspector(s): George Ordija and Martin Tippin

Unit 4

1. Block Diagram



There are two air preheaters per boiler (same as Unit 3). The preheaters extend vertically downwards from their respective economizer outlets for approximately 20 feet. The outlet of each preheater makes a 90-degree bend and connects to separate rectangular ducts. Each duct is approximately 6 feet high by 30 feet wide. The ducts traverse horizontally for approximately 60 feet before entering a split ESP plenum. The first ten feet of the horizontal ductwork is inside the boiler building. The remaining ductwork is outside.

2. SO3 injection
The facility does not use SO3 injection.

3. Flue gas conditioning
No other flue gas conditioning is utilized.

4. Other Information
Low sulfur coal is utilized. All boilers incorporate low NOx technology and over-fired air.

#6 – Midwest Generation (Joliet)

Source: Midwest Generation, LLC – Unit 6
Address: 1601 S. Patterson Rd., Joliet, IL 60436
Contact/Title: Daniel Maul/Operations Mgr.
Inspectors: Terry Samnadda and Jose Mora.

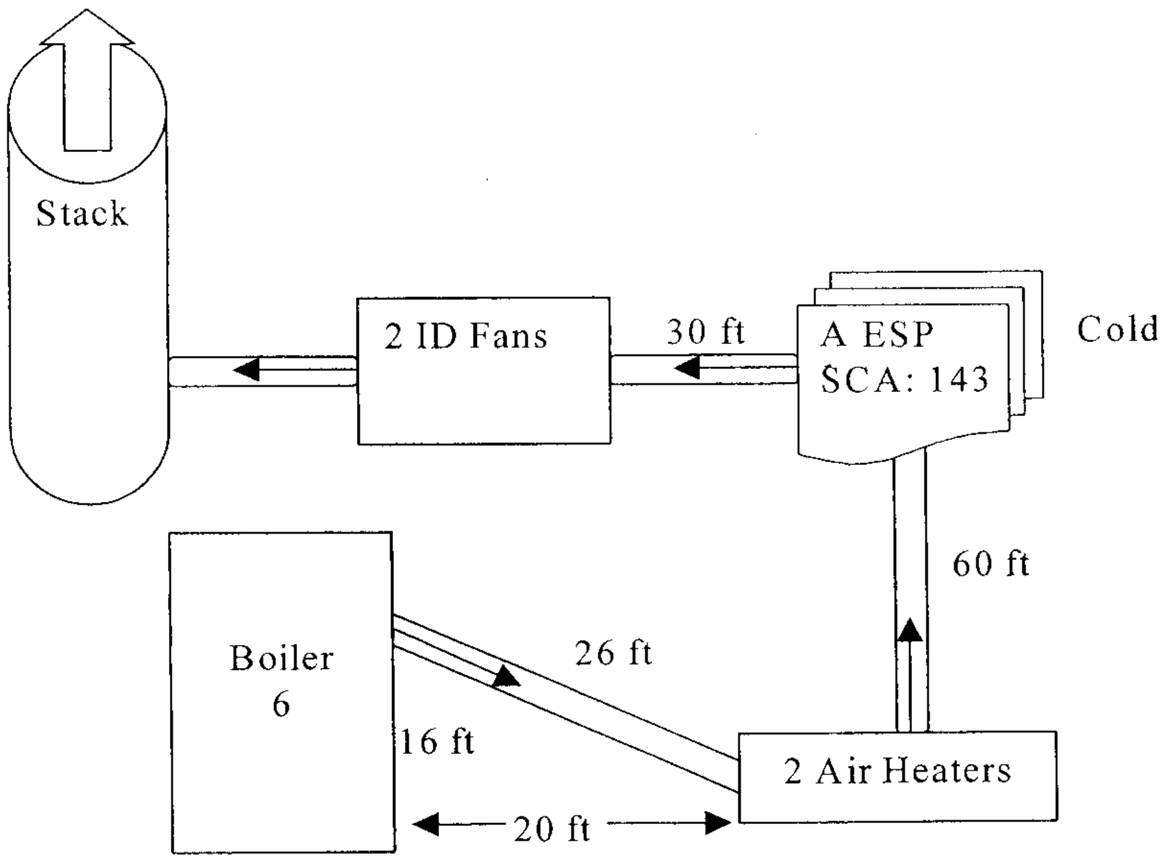
Date: May 4, 2006
I.D. #: 197809 AAO
Phone #: (815) 207-4915

Unit 6

Gross Power Output: 333 MW/Hr
Manufacturer: Babcock/Wilcox

Heat Input: 3543 MBtu/Hr
Type of Boiler: Cyclone

1. Block Diagram



Two 26' rectangular ducts near the top of the boiler drop approximately 1 story at an angle of 45 degrees entering two air heaters (A & B). Two 15'x24' rectangular ducts exiting from the air heaters upwards through the roof 60' to a cold ESP. The ducts fan out before entering the ESP. Two rectangular ducts originated from the ESP are routed to two ID fans (A & B). Then, the two ducts from the latter ID fans are routed to the stack without merging.

2. SO_3 injection system: None
3. Flue gas conditioning system: None
4. Nitrogen oxide emissions are controlled by over fired air/Gas return system. ESP controls particulate matter emissions.
5. Pulverized coal is used in this unit. The coal is from Powder River Basin in Wyoming.

Source: Midwest Generation, LLC – Unit 7.
Address: 1800 Channahon Rd., Joliet, IL 60436
Contact/Title: Scott Perry/Operations Manager
Inspectors: Terry Samnadda & Jose Mora

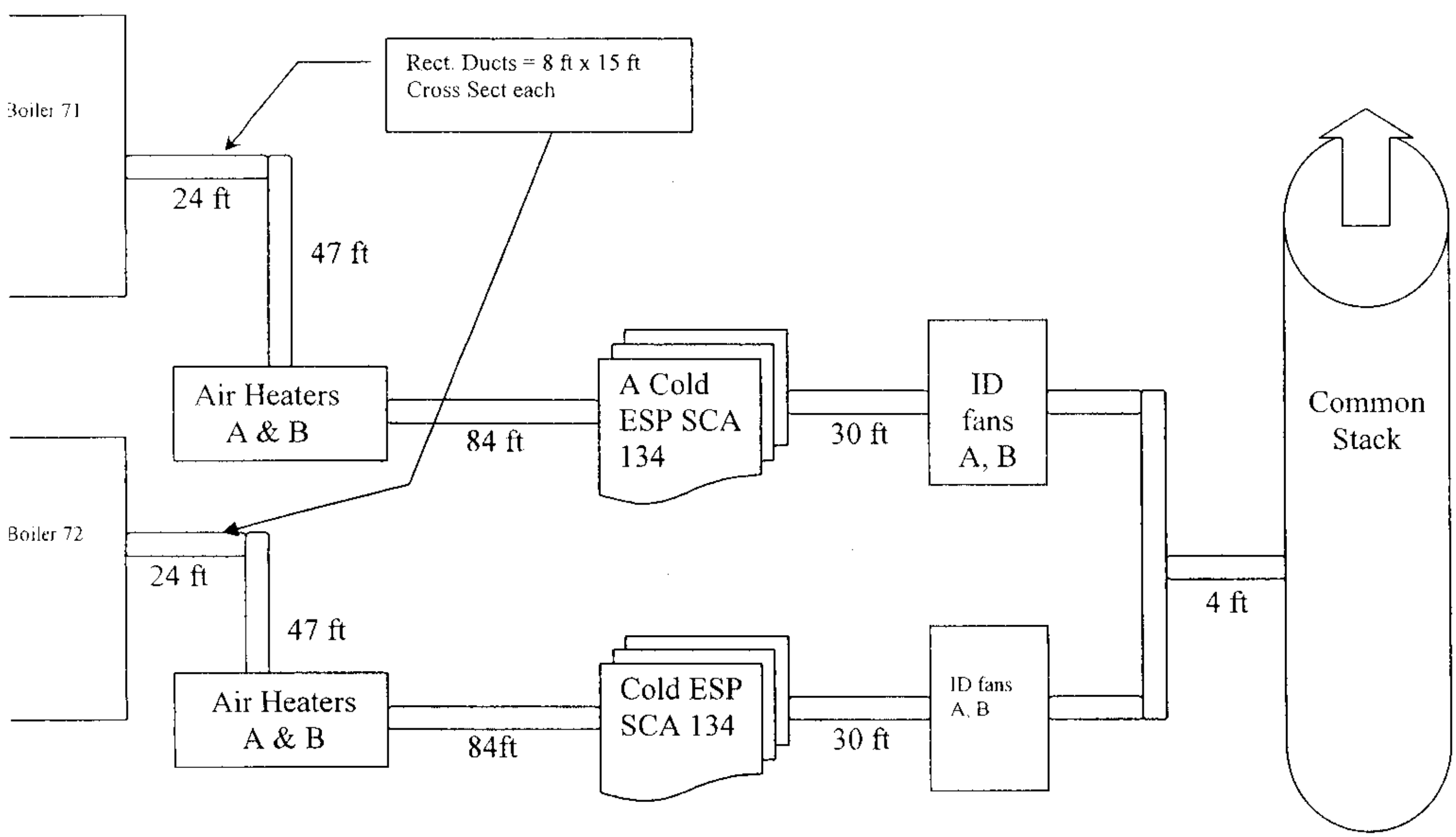
Date: May 4, 2006
I.D. #: 197809 AAO
Phone#: (815) 207-5415

<u>Unit 7</u>

Gross Power Output: 555 MW/Hr
Manufacturer: Combustion Engineering

Heat Input: 6034 MBtu/Hr (total)
Type of Boilers: Tangential

1. <u>Block Diagram</u>



Boilers 71 and 72 have identical ductwork and similar equipment configuration. Boiler 71 rises about 10 stories high. A single ductwork exits from boiler 81 and splits into two 8'x15' rectangular ductworks. The latter ductworks exiting from the boiler are located approximately at a height of 7 stories and drop 3 stories to their respective A and B air heaters. Each story height is about 16ft. Two 15'x40' rectangular ductworks originating from the air heaters are routed to a cold ESP. The distance between the air heaters and the ESP is about 84 ft. Then, a single ductwork exits from the ESP and splits into two identical rectangular ductworks to their respective A and B ID fans. The distance between the ESP and the ID fans is about 30 feet. The latter ductworks from the ID fans merge into a single ductwork entering the stack. The distance between the junction of the ID fans and the stack is about 4 ft.

2. SO_3 injection system: None.
3. Flue gas conditioning system: None
4. Low sulfur coal is utilized (Sulfur content: 0.18% to .40%).
5. Pulverized coal is used in this unit. The coal is from Powder River Basin in Wyoming.
6. Nitrogen oxide emissions are controlled by low NOx burners and over fired air system. ESP's controls particulate matter emissions.

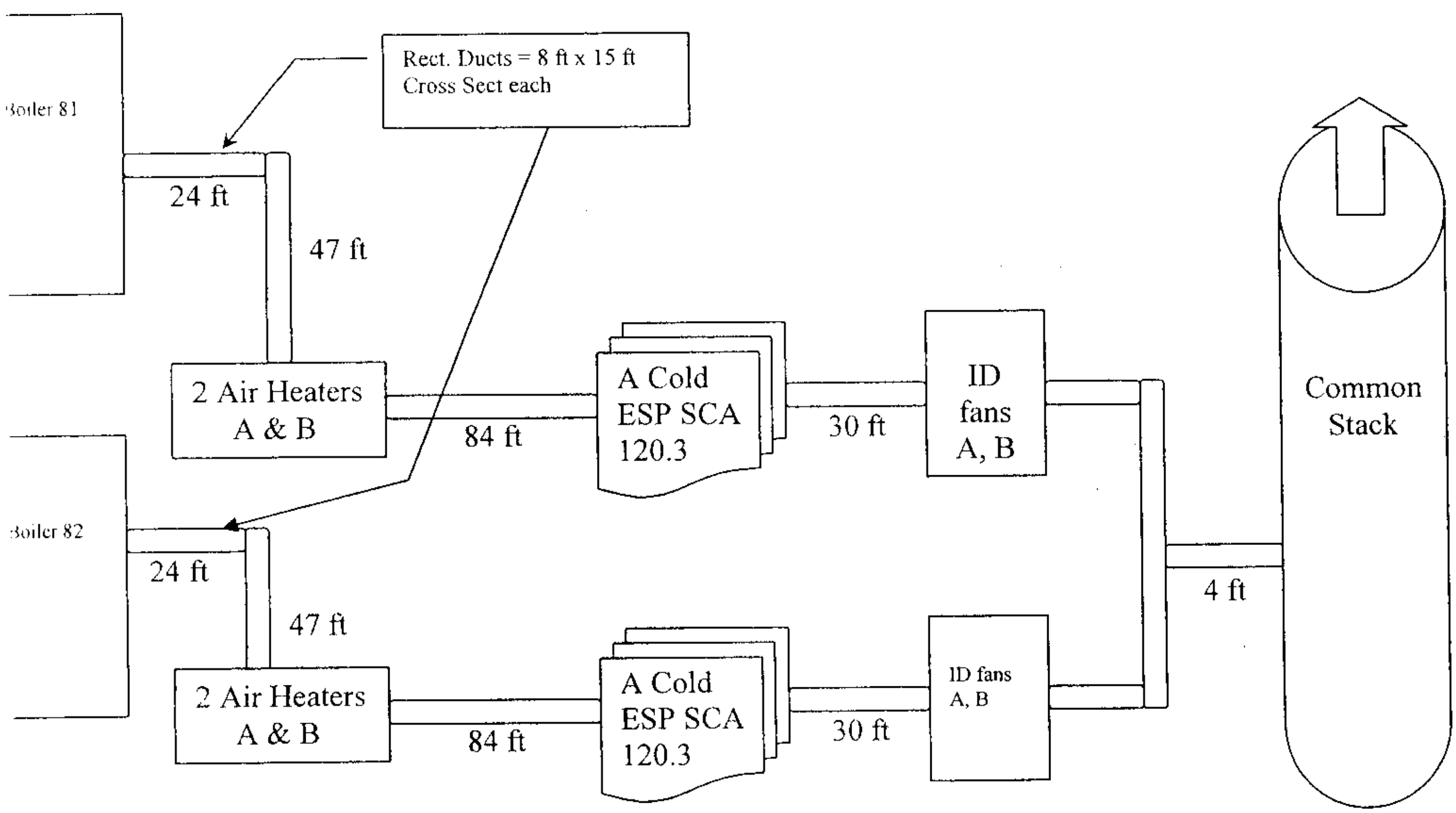
Source:	Midwest Generation, LLC – Unit 8.	Date: May 4, 2006
Address:	1800 Channahon Rd., Joliet, IL 60436	I.D. #: 197809 AAO
Contact/Title:	Scott Perry/Operations Manager	Phone #: (815) 207-5415
Inspectors:	Terry Samnadda & Jose Mora	

Unit 8

Gross Power Output: 557 MW/Hr
Heat Input: 6386 MBtu/Hr (total)

Type of Boilers: Tangential
Manufacturer: Combustion Engineering

1. Block Diagram



Boilers 81 and 82 have identical ductwork and similar equipment configuration. Boiler 81 rises about 10 stories high. A single ductwork exits from boiler 81 and splits into two 8'x15' rectangular ductworks. The latter ductworks exiting from the boiler are located approximately at a height of 7 stories and drop 3 stories to their respective A and B air heaters. Each story height is about 16ft. Two 15'x40' rectangular ductworks originating from the air heaters are routed to a cold ESP. The distance between the air heaters and the ESP is about 84 ft. Then, a single ductwork exits from the ESP and splits into two identical rectangular ductworks to their respective A and B ID fans. The distance between the ESP and the ID fans is about 30 feet. The latter ductworks from the ID fans merge into a single ductwork entering the stack. The distance between the junction of the ID fans and the stack is about 4 ft.

2. SO_3 injection system: None
3. Flue gas conditioning system: None
4. Low sulfur coal is utilized (Sulfur content: 0.18% to .40%).
5. Pulverized coal is used in this unit. The coal is from Powder River Basin in Wyoming.
6. Nitrogen oxide emissions are controlled by low NOx burners and over fired air system. ESP controls particulate matter emissions.

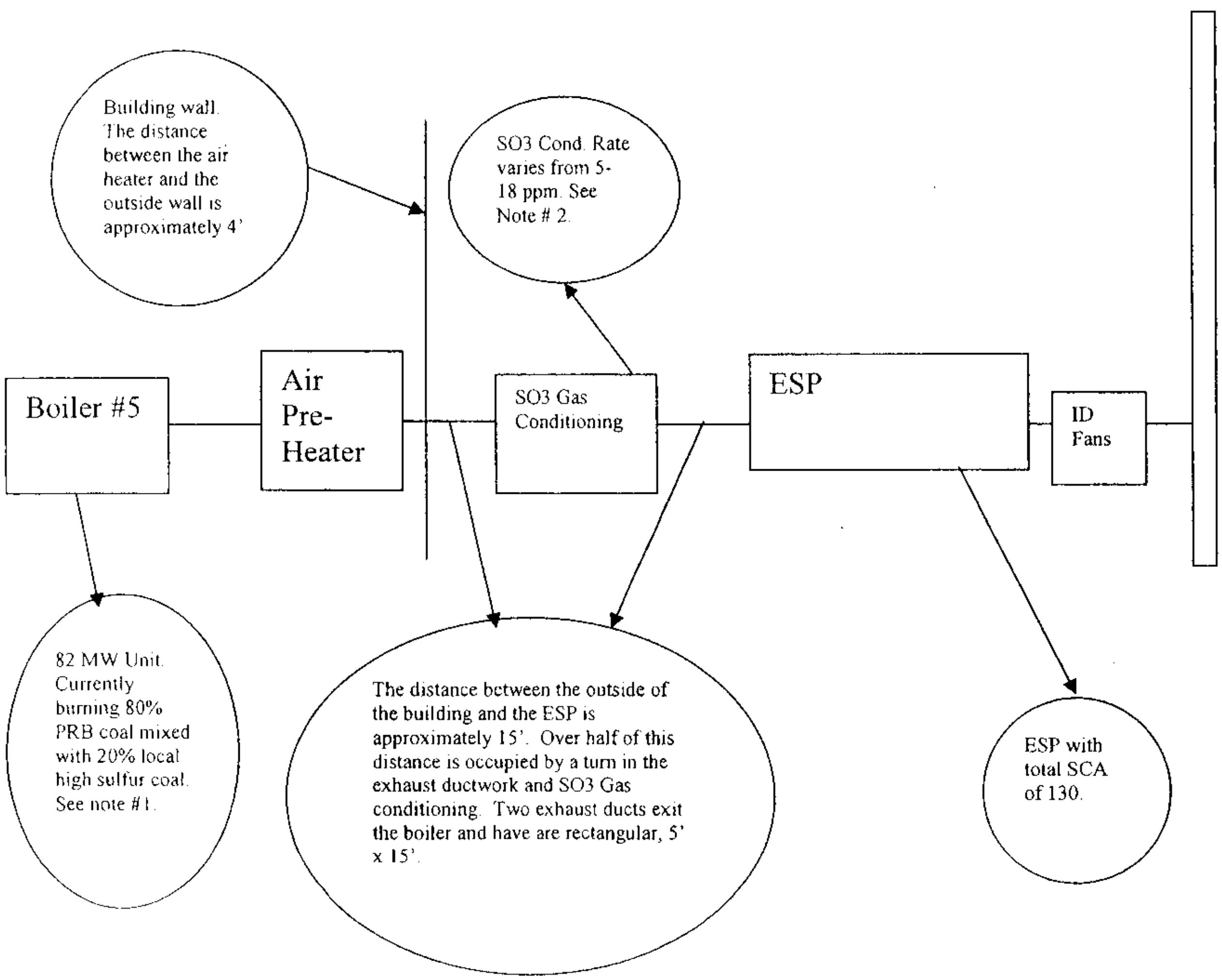
#7 – Ameren Energy Generating – Hutsonville

Source:	Ameren Energy Generating Company-Hutsonville Station
I.D. #:	033801AAA
Address:	R.R. #1, Hutsonville, Illinois
Contact/Title:	Steve Whitworth/Supervising Environmental Scientist
Phone/fax:	314.554.4908/314.544.4182
Inspector:	Ron Robeen, FOS Engineer
Date:	May 4, 2006

Note #1. Currently the source is using up the last of the stockpile of local coal on site. Once this stockpile is used, they will begin burning 100% PRB Coal.

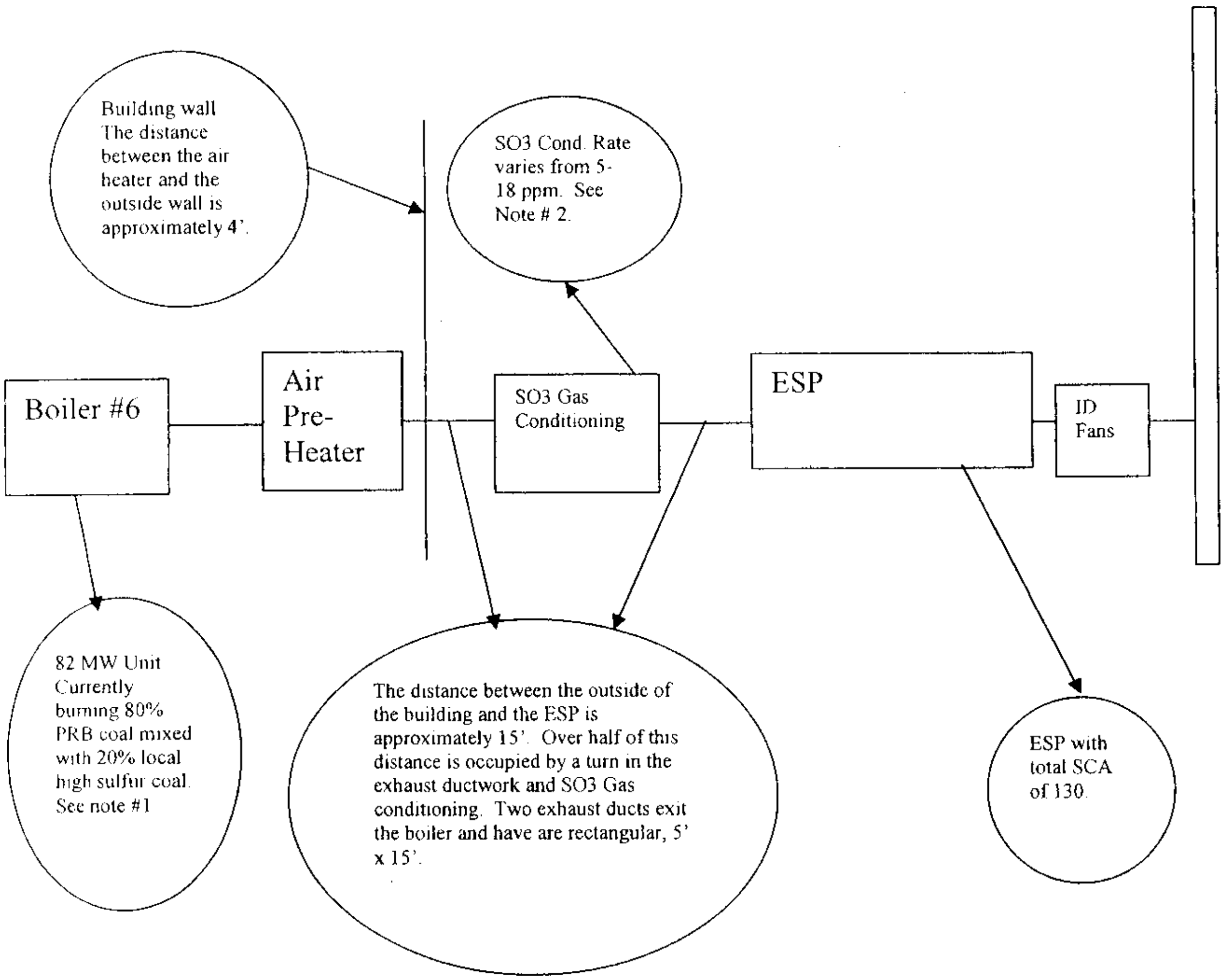
Note #2. Elemental sulfur is received in pellet form. It is burned in a heater to SO2 and then sent across a catalyst bed to convert to SO3 for injection.

Boiler #5



Ameren Energy Denerating Company-Hutsonville Station
I.D. #: 033801AAA

<u>Boiler #6</u>

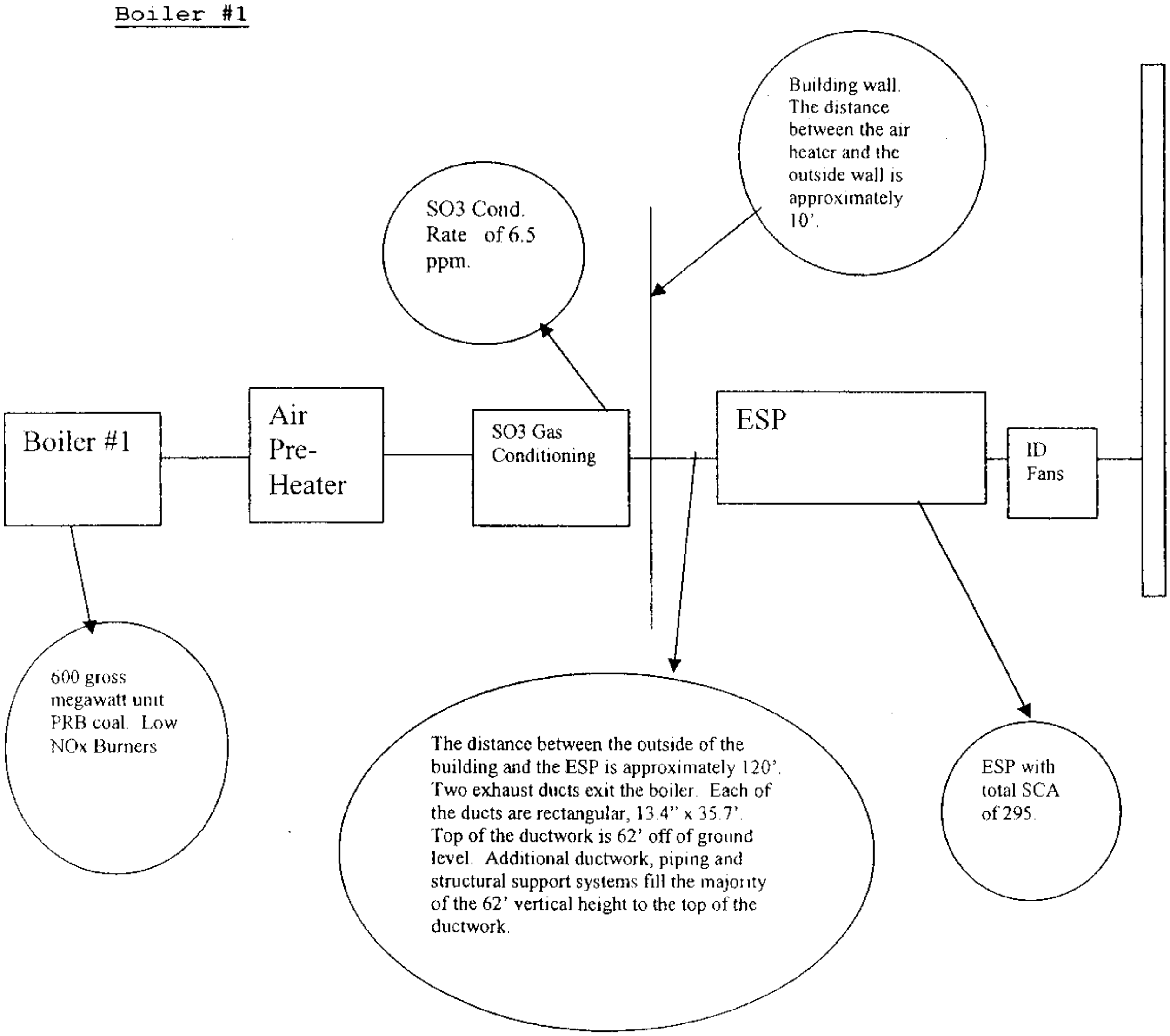


#8 – Ameren Energy Generating (Newton)

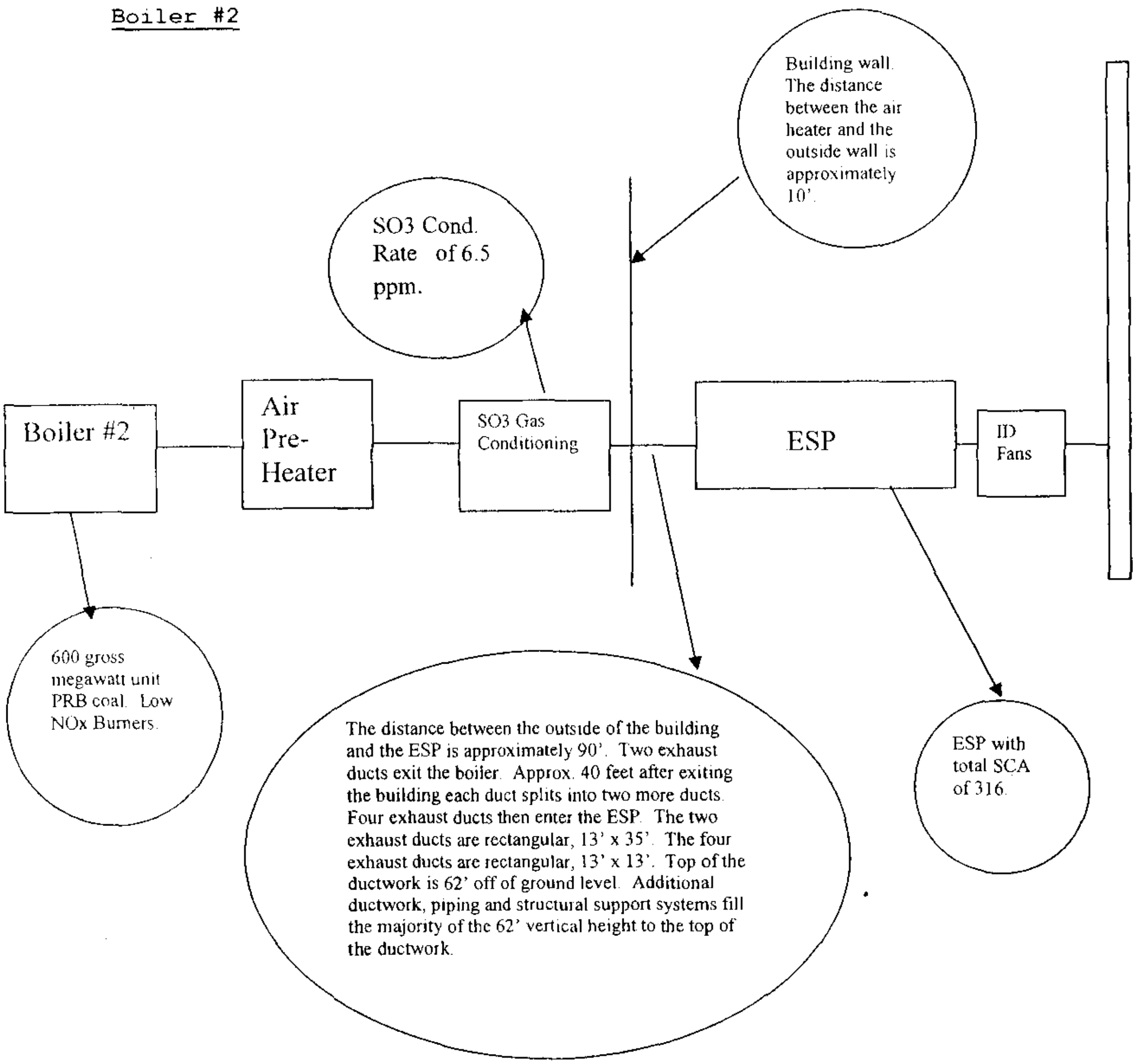
Source:	Ameren Energy Generating Company-Newton Power Station
I.D. #:	079808AAA
Address:	6725 North 500th Street, Newton, Illinois 62448
Contact/Title:	Steve Whitworth/Supervising Environmental Scientist
Phone/fax:	314.554.4908/314.544.4182
Inspector:	Ron Robeen, FOS Engineer
Date:	May 4, 2006

Note #1. Elemental sulfur is received in liquid form. It is burned in a heater to SO2 and then sent across a catalyst bed to convert to SO3 for injection.

Boiler #1



Ameren Energy Generating Company-Newton Power Station
I.D. #: 079808AAA



#9 – Ameren Energy Generating (Coffeen)

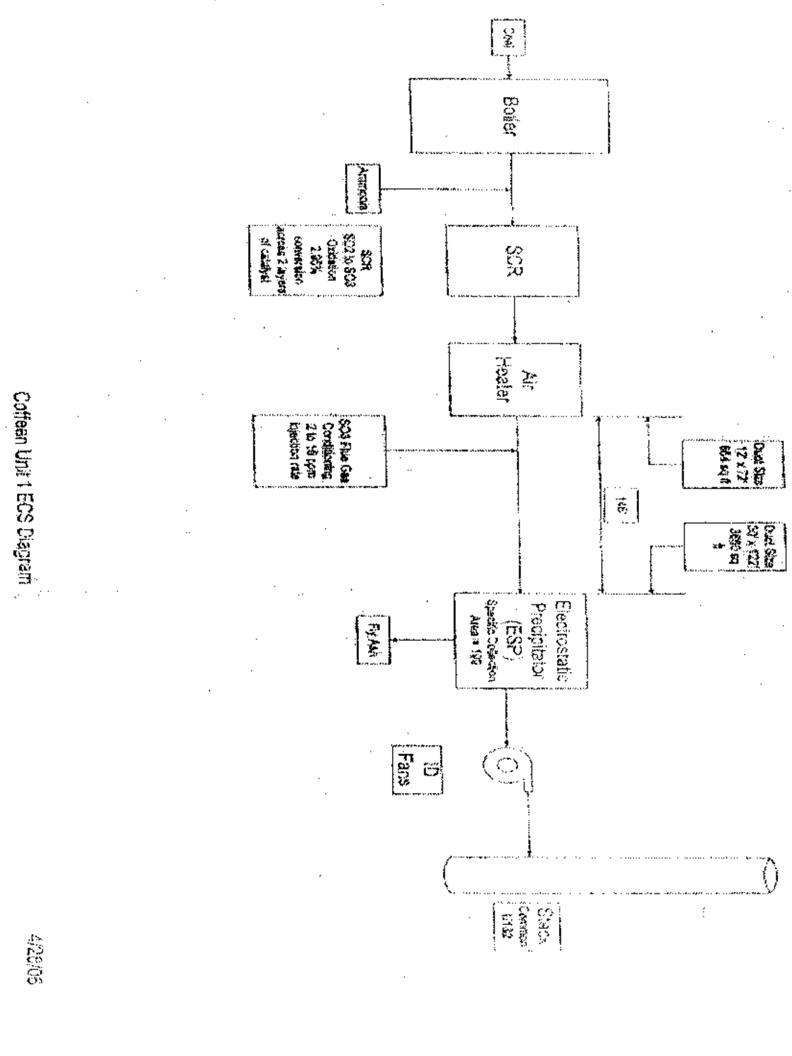
Tier I Inspection Memorandum

Date: May 3, 2006
To: J. Ross
From: L. Brinkmann, S. Youngblut

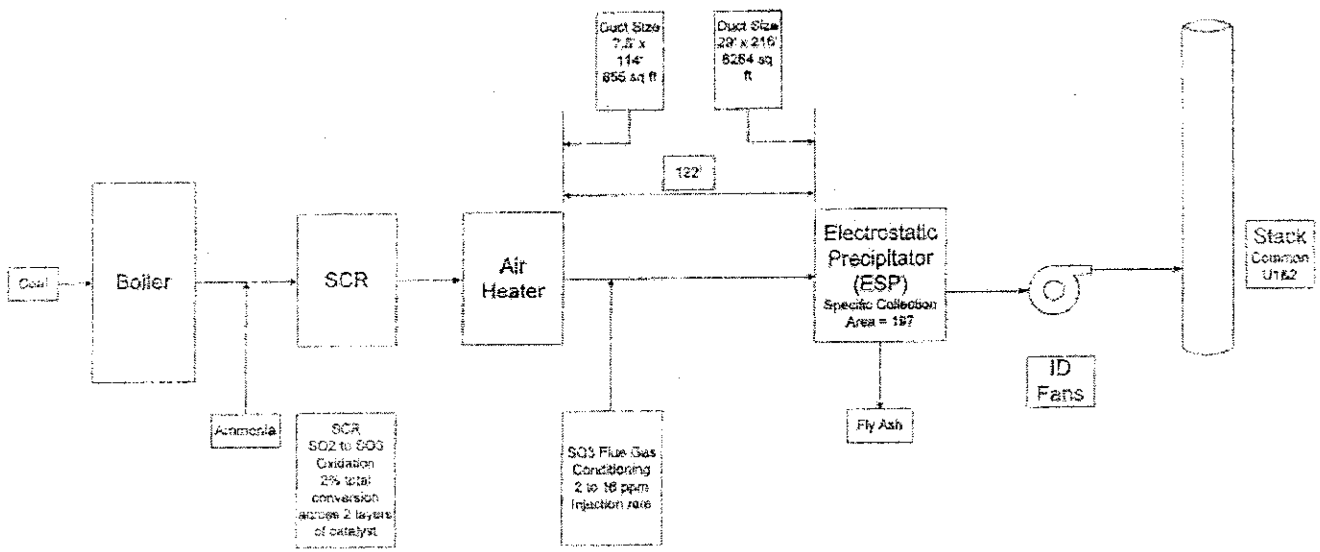
Date of Inspection: May 3, 2006
Last Insp. Date: May 19, 2005
I.D.#: 135803AAA **R/D:** 207
County: Montgomery

Source: Ameren Services-Coffeen Power Station
Address: RR 1 , Coffeen
Contact/Title: Robert LaPlaca/Consulting Environmental Scientist (St. Louis), John Romang/ Chemistry and Environmental Supervisor, James Klenke/ Plant Engineer
Phone: 217/584-7153, 314/544-3647

1. Block Diagram
   a) Coffeen Unit 1



b) Coffeen Unit 2



Coffeen Unit 2 ECS Diagram

4/28/06

2. An SO_3 flue gas conditioning system has been installed on Units 1 and 2. A 3,000 molten sulfur tank supplies sulfur that is used to make SO_2 for both units. The SO_2 is forced into SO_3 and put into the flue gas. With a letter dated August 2, 2001, Steve Whitworth notified the Agency that the flue gas conditioning system for Unit 1 was placed into service on July 16, 2001 and released to operations on July 17, 2001. The flue gas conditioning system for Unit 2 was placed in service on July 10, 2001 and released to operations on July 13, 2001. During the inspection, both units were operating and the SO_3 injection rate for Units 1 and 2 was 9ppm and 10ppm, respectively. The facility burns Powder River Basin coal and East Hornsby Coal. The SO_3 injection system is used for both.

3. No other flue gas conditioning is performed.

4. The coal-fired boilers are designated as Unit 1 (CB-1) and Unit 2 (CB-2). They have a steam production capacity of 2.5 million pounds per hour and 4.159 million pounds per hour, respectively. Both are Babcox and Wilcox subcritical cyclone-fired units. Unit #1 and Unit #2 have overfire air systems for reducing NOx emissions. According to an email from the facility dated May 16, 2002, "full utilization of the overfire air systems on Unit #1 and Unit #2 was not realized until late in 2001 and early 2002". The overfire air systems did not have full capability until the fine grind crushers were installed. The overfire air systems operate all year.

   The facility installed selective catalytic reduction (SCR) systems on both units. The manufacturer will not guarantee the catalyst in the SCR during ozone season while burning low sulfur coal. The SCR mixes ammonia with the exhaust gas. It is located before the precipitator on the hot side. There are two 50,000 gallon anhydrous ammonia tanks for supplying the SCR units. The SCR system operates May through September. It needs to operate at about 800 degrees Fahrenheit for optimum performance. The SCR on Unit #2 initially started up on April 9, 2002. The SCR on Unit #1 was in service May 1, 2003.

#10 – Ameren Energy Generating (Meredosia)

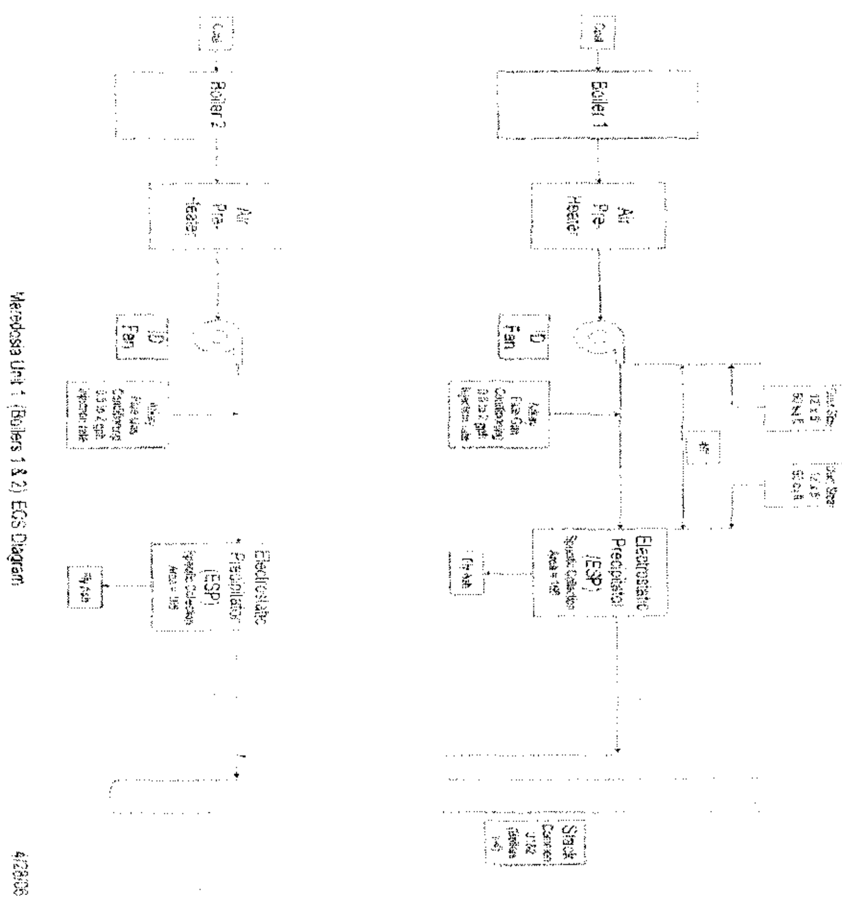
Tier I Inspection Memorandum

Date: May 2, 2006	**Date of Inspection:** May 2, 2006
To: J. Ross	**Last Insp. Date:** May 26, 2005
From: L. Brinkmann, S. Youngblut	**I.D.#:** 137805AAA **R/D:** 207
	County: Morgan

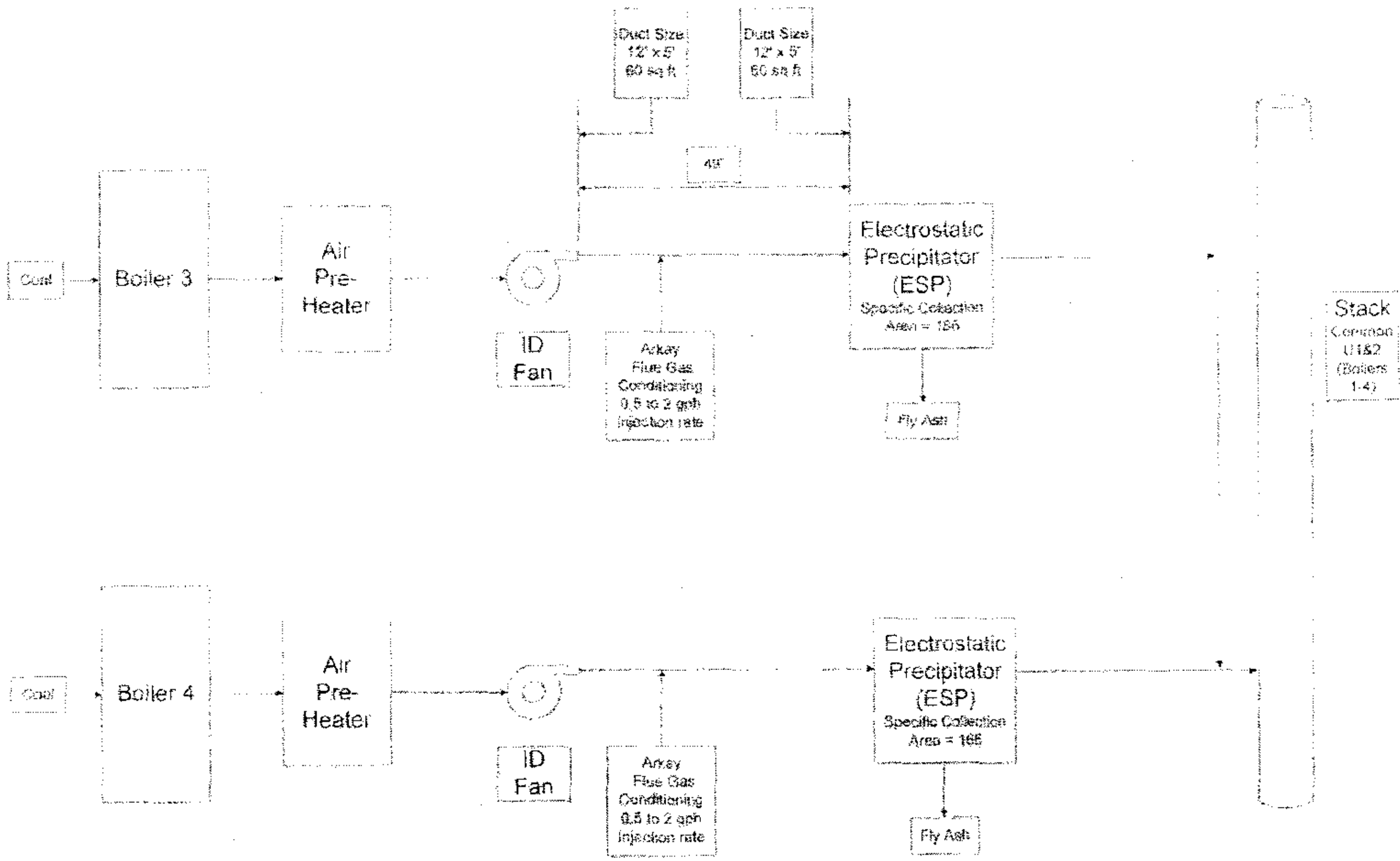
Source: Ameren Services-Meredosia Power Station
Address: 800 South Washington, Meredosia
Contact/Title: Janine Maxwell/ Chemistry Environmental Supervisor, Robert LaPlaca/Consulting Environmental Scientist (St. Louis)
Phone: 217/584-7153, 314/544-3647

1. Block Diagram

   a) Unit 1 (Boilers 1 & 2)



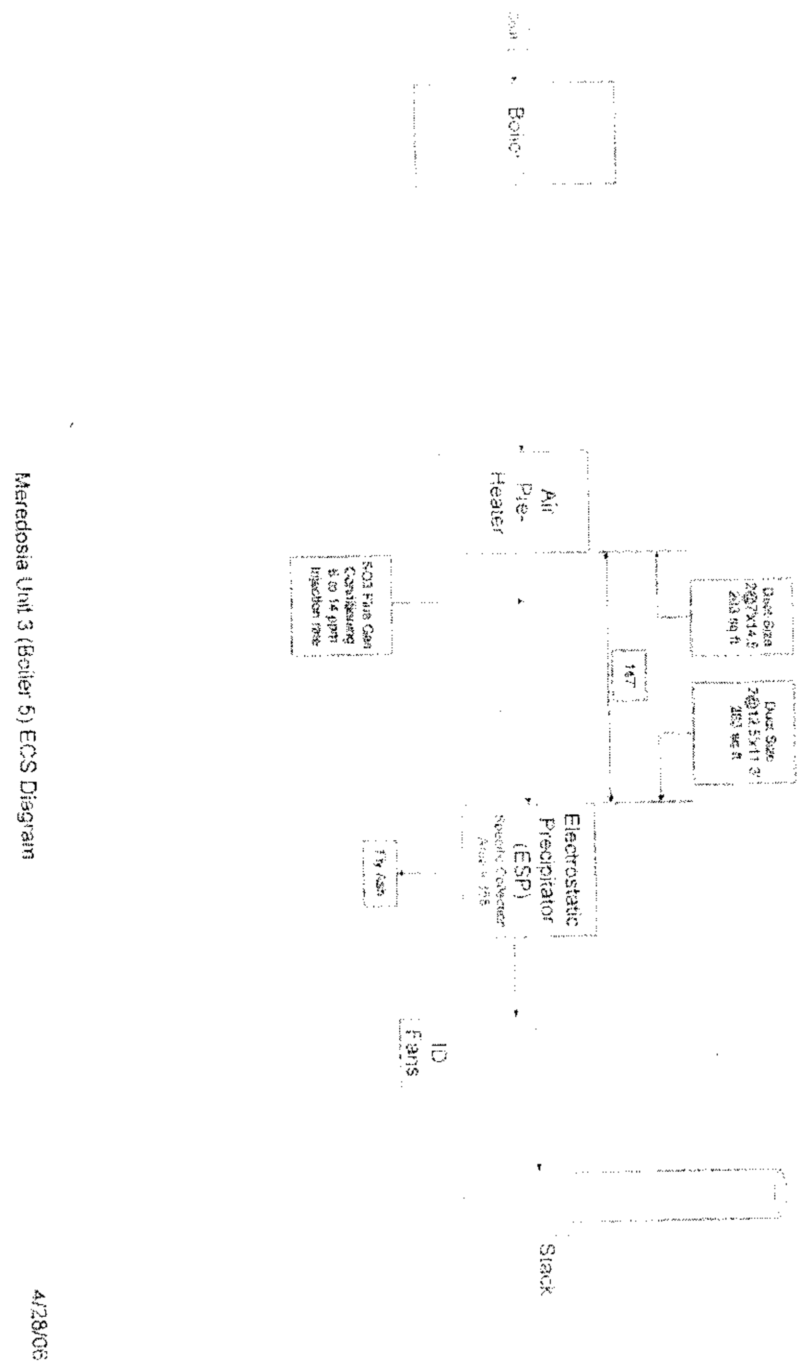
b) Meredosia Unit 2 (Boilers 3 & 4)



Meredosia Unit 2 (Boilers 3 & 4) ECS Diagram

4/28/06

c) Meredosia Unit 3 (Boiler 5)



2. The facility performs SO_3 injection on Boiler #5. Boiler #5 (unit 3) is a 220 MW coal-fired boiler equipped with a low NOx burner system. It has an electrostatic precipitator and a sulfur dioxide monitor. The boiler is burning Powder River Basin coal which contains low sulfur. A flue gas conditioning system was installed on boiler #5. It was needed for burning the low sulfur coal. The flue gas conditioning system burns molten sulfur making SO_2. The system oxidizes the SO_2 into SO_3. The SO_3 is put into the flue gas which lowers the resistivity of the fly ash making it easier for the precipitator to collect. The system was place in service on March 22, 2003 and was operating reliably April 14, 2003. During the inspection, SO_3 was being injected at a rate of 7.98 ppm. The system has the capability of injecting SO_3 at a rate of 6 to 14 ppm.

3. Flue gas conditioning is also performed on Boiler #4. A non-sulfur liquid conditioning agent called Arkay is used. The facility was issued a construction permit (#06010047) on February 16, 2006 to do a "pilot evaluation of an alternative flue gas conditioning agent" on Boilers #1-5. The facility has immediate plans to install the Arkay flue gas conditioning systems on Boilers #1-3 after receiving the construction permits. They plan to make the Arkay system on Boiler #4 a permanent system and no longer a "pilot evaluation".

4. The Meredosia power station has a total of six boilers divided into four units. There are two coal-fired boilers (#1 and #2) with a generating capacity of 32 MW each. There are also two coal-fired boilers (#3 and #4) with a generating capacity of 30 MW each. The boilers #1-#4 have a common stack. The units are equipped with SO2, NOx, and opacity monitors. Boiler #5 (unit 3) is a 220 MW coal-fired boiler equipped with a low NOx burner system. It has an electrostatic precipitator. Boiler #5 has a separate stack.

#11 – Ameren Energy Resources – (Duck Creek)

ID: 057 805 AAA
Ameren Energy Generating
Field Inspection Report

TIER I INSPECTION MEMORANDUM

Date: May 3, 2006 **Date of Inspection:** May 3, 2006

To: Ed Bakowski

From: W.Kahila **ID:** 057 801 AAA **R/D:** 202

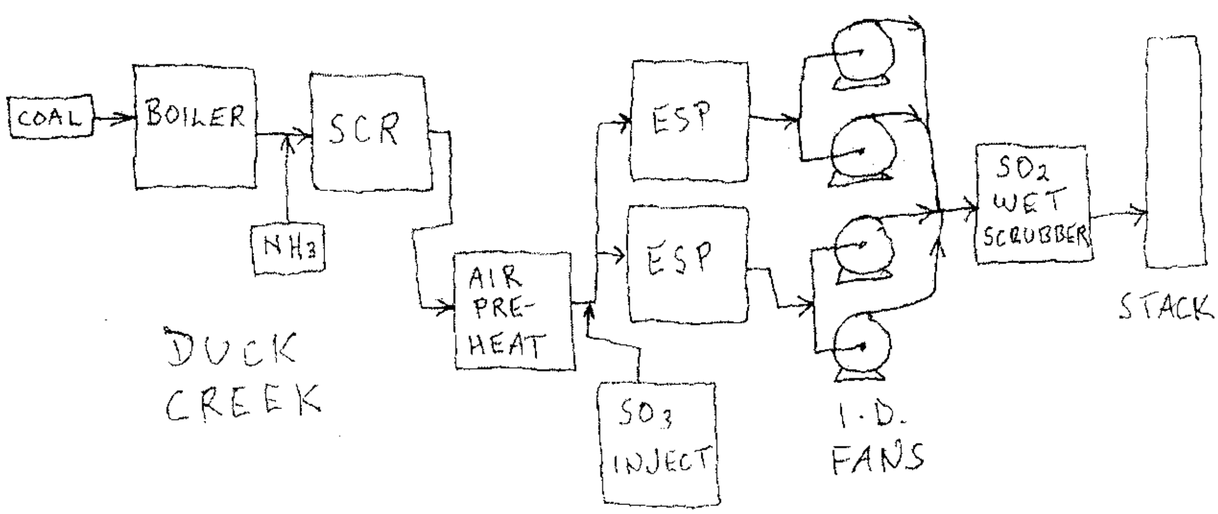
Source: Ameren Energy Generating, Duck Creek Station
Address: 17751 N. Cilco Road, Canton, IL
Contact: Jim Chaney, Plant Engineer **Phone:** 309 633 2852
Steve Whitworth, Corporate Office, St. Louis, MO

Purpose of Inspection:

Coal-fired power plant equipment verification/clarification.

Findings:

Block diagram:



This facility is an electric generating station with one boiler, a pulverized coal, wall fired boiler rated at 3,713 million BTU per hour or about 400 MW.

For NOx control there are low NOx burners on the boiler and a SCR system with ammonia injection. Particulates are controlled by two parallel, cold side, ESP's with flue gas conditioning by means of SO_3 injection. Sulfur dioxides are controlled by a limestone wet scrubber system.

The SO_3 injection system was just started up in March 2006. The proper permits were obtained. The coal presently being used can be described as a medium sulfur content coal of up to 2%. This amount is high enough to continue to require the use of the wet scrubber for SO_2 control, but low enough to require flue conditioning with SO3 injection for proper ESP performance. The ESP's were designed for use with high sulfur coal, but with the lower sulfur coal, SO_3 needs to be injected to modify the resistivity of the flyash particles for proper ESP operation.

The current scrubber is reaching the end of its life. The company is currently investigating whether rebuilding the scrubber or replacing the scrubber is most economic. If the scrubber system needs to be shutdown while a new one is built or rebuilt, then low sulfur will be temporarily used to meet the SO_2 emission limits.

The SCR was put into service in about June 2003 and presently operates from May through September, the ozone season. New rules may require year round operation by 2009. The SCR system produces a little SO_3 so the SO_3 injection system is operated at a reduced rate in proportion to the amount from the SCR to maintain about 10 ppm of SO_3 in the flue gas.

The duct between the air heater and the ESP's is about 212 feet long but is not in a straight line. The single duct connection at the pre-heater is 14 x 25 feet (352 sq. ft.) and it splits into two sections, one for each ESP. Each connection to the ESP's is 7 x 33 feet (464 sq. ft.) The specific collection area (both ESP's combined) is 291.

Rizwan Syed and Wayne Kahila, both from the Peoria Regional Office, did this inspection.

cc: W.Kahila
R.Syed
ID: 057 801 AAA

ID: 143 805 AAG
Ameren Energy Generating
Field Inspection Report

TIER I INSPECTION MEMORANDUM

Date: May 2, 2006 **Date of Inspection:** May 2, 2006

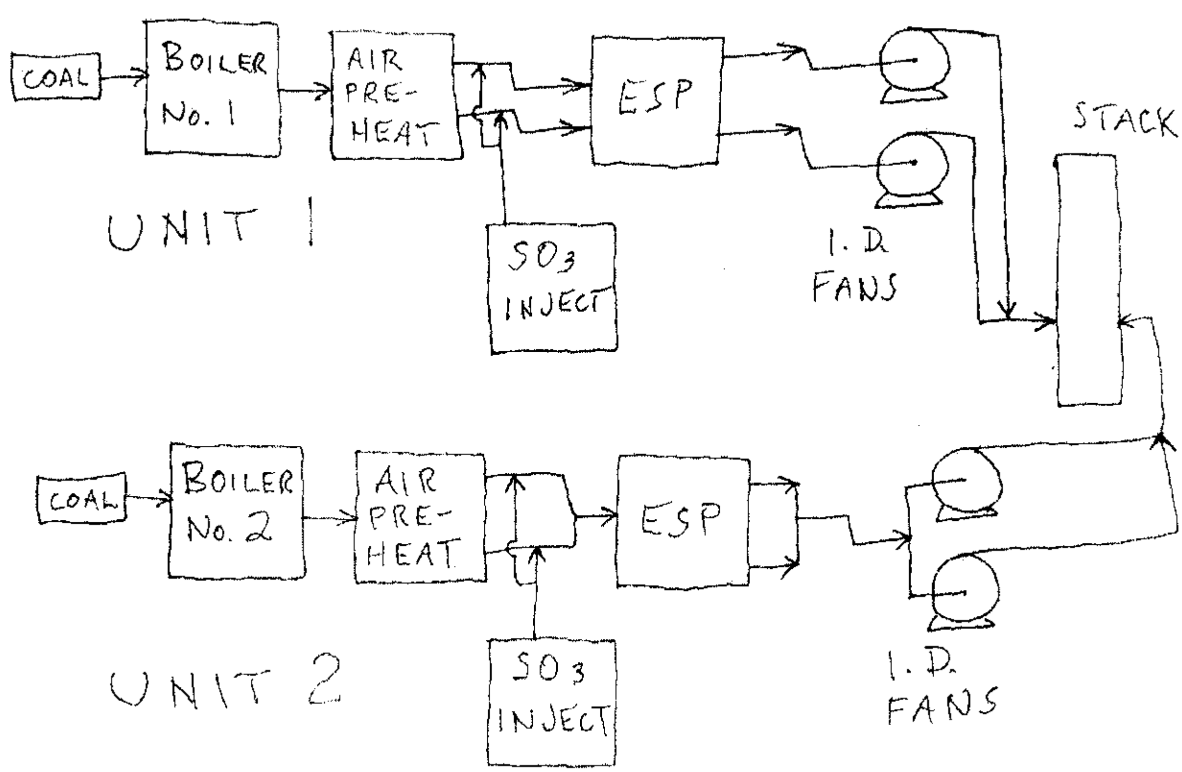
To: Ed Bakowski

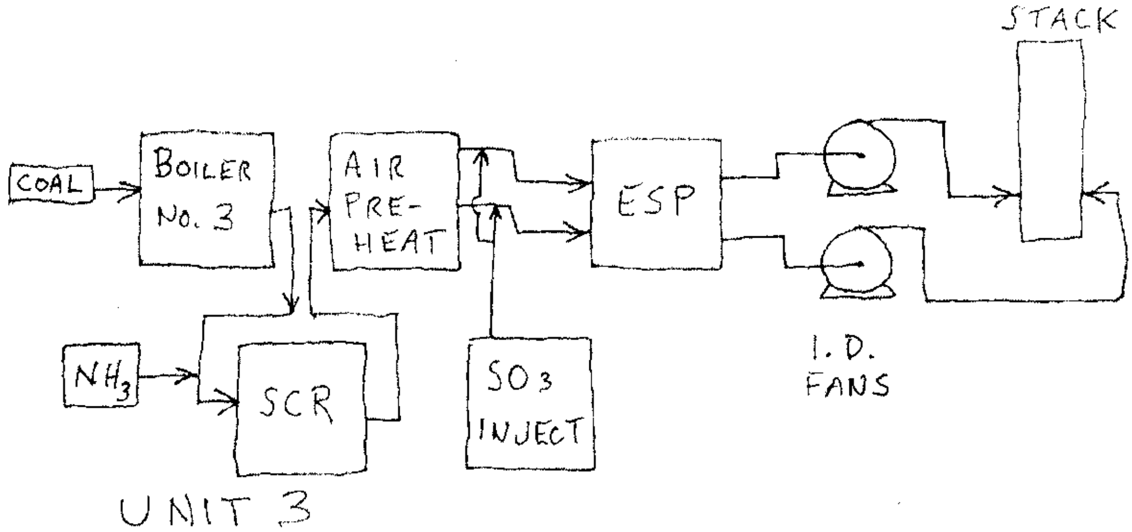
From: W.Kahila **ID:** 143 805 AAG **R/D:** 201

Source: Ameren Energy Generating
Address: 7800 S. Cilco Lane, Bartonville, IL 61607
Contact: Jim Caney, Plant Engineer **Phone:** 309 633 2833

Purpose of Inspection: Coal-fired power plant equipment verification/clarification

Findings: Block diagrams:





This facility is a power generating station with three coal-fired boilers. Each unit has its own ESP, and Units 1 and 2 exhaust through one stack, and Unit 3 goes through its own stack. Unit 3 has a Selective Catalytic Reduction system that uses ammonia and a catalyst to reduce NOx emissions. All three boilers are pulverized coal, wall fired boilers.

Approximate maximums:

Unit No. 1	128 MW
Unit No. 2	275 MW
Unit No. 3	365 MW

This facility was owned by Central Illinois Light Company (CILCO), and then AES Corporation, but is now part of Ameren Corporation and is now named the Ameren Energy Generating, Edwards Power Plant. This facility generates electric power from three coal-fired units. Coal is delivered to the facility by mostly rail but it can be delivered by truck. Coal is unloaded onto a conveyor system that transports the material to the reclaim pile or to the coal bunkers. Coal is transferred via conveyor belts and transfer houses where several transfers of the material occur in enclosed environments.

Fuel oil and natural gas are used for startup and flame stabilization. All three units are currently equipped with low NOx burners. Particulate emissions are controlled by electrostatic precipitators with flue gas conditioning by means of SO_3 injection. All ash produced is directed to the ash pond for disposal. The SO_3 injection system is listed in the Title V permit and the older state operating permits. All of my inspection reports for the last 20 plus years have also described this system.

Sulfur dioxide is controlled by burning coal with the proper sulfur content. The average SO_2 emissions from all three boilers are limited to 4.71 lbs. SO_2/million BTU. Any one boiler may have up to 6.6 lbs. SO_2/million BTU as long as the overall average is not exceeded. Also, on a plant wide basis, the 24-hour average for SO_2 emissions shall not exceed 34,613 lbs. SO_2/hour. Reports of coal analyses have been submitted to the Agency in a timely manner. Quarterly reports of the sulfur dioxide monitoring have been submitted in a timely manner.

Unit 1:

The ESP is a cold side one. The duct from the air pre-heater to the ESP is a twin duct. Each section is 7 x 20 feet (274 sq. ft.) at the outlet of the pre-heater and 16 x 34 feet (1088 sq. ft.) at the inlet to the ESP. The total duct length is about 61 feet; however, this is not a straight line distance. There are many curves and angles in this length of duct. The equipment is tightly squeezed together.

The ESP specific collection area is 138.

The only flue gas conditioning is SO_3 injection. Elemental sulfur is burned to make SO_2 and a catalyst converts the SO_2 into SO_3. The injection averages about 10 ppm of SO_3. The SO_3 system is necessary for the ESP to work properly with low sulfur coal since the ESP was designed to operate with high sulfur coal.

Unit 2:

The ESP is a cold side one. The duct from the air pre-heater to the ESP is a twin duct leaving the pre-heater but is combined into a single inlet at the ESP. Each section is 11 x 28 feet (612 sq. ft.) at the outlet of the pre-heater and 27 x 74 feet (1968 sq. ft.) at the inlet to the ESP. The total duct length is about 46 feet; however, this is not a straight line distance. There are many curves and angles in this length of duct. The equipment is tightly squeezed together.

The ESP specific collection area is 170.

The only flue gas conditioning is SO_3 injection. Elemental sulfur is burned to make SO_2 and a catalyst converts the SO_2 into SO_3. The injection averages about 8 ppm of SO_3. The SO_3 system is necessary for the ESP to work properly with low sulfur coal since the ESP was designed to operate with high sulfur coal.

Unit 3:

The ESP is a cold side one. The duct from the air pre-heater to the ESP is a twin duct. Each section is 12 x 29 feet (638 sq. ft.) at the outlet of the pre-heater and 32 x 49 feet (3056 sq. ft.) at the inlet to the ESP. The total duct length is about 31 feet; however, this is not a straight line distance. There are many curves and angles in this length of duct. The equipment is tightly squeezed together.

The ESP specific collection area is 178.

The only flue gas conditioning is SO_3 injection and SCR system. Elemental sulfur is burned to make SO_2 and a catalyst converts the SO_2 into SO_3. The injection averages about 12 ppm of SO_3. The SO_3 system is necessary for the ESP to work properly with low sulfur coal since the ESP was designed to operate with high sulfur coal.

Unit 3 also has a SCR system with ammonia injection. Data from the catalyst manufacturer indicates that the catalyst in the SCR converts about 1% of the entering SO_2 into SO_3. The rate of the SO_3 injection system is adjusted to account for the SO_3 from the SCR system so that the total SO_3 is about 12 ppm. Presently the SCR system operates only during the ozone season, which is May through September. It may go to year round operation in 2009.

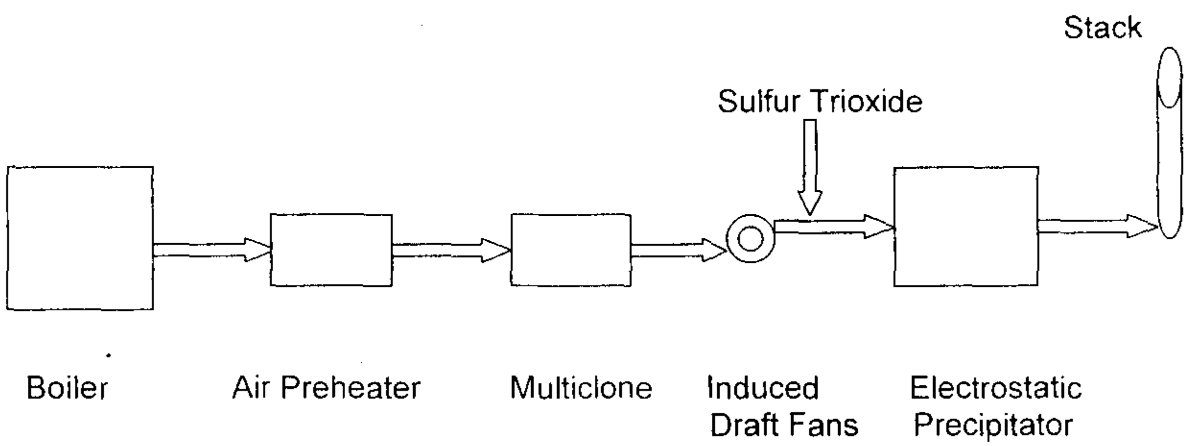
Rizwan Syed and Wayne Kahila, both of the Peoria Regional Office, did this inspection.

cc: W.Kahila
R.Syed
ID: 143 805 AAG

#13 – Dynegy Midwest Generation (Wood River)

Source: Dynegy Midwest Generation, Inc.
I.D. 119020AAE
Address: #1 Chessen Lane, East Alton, Illinois 62002
Contact/Title: Natalie Locke/Environmental and Don Crone/Supervisor
Phone/Fax: 217/872-2359 and 618/462-9251
Inspectors: Jeff Benbenek and John Justice
Date of Determination: April 28, 2006

Boiler #4



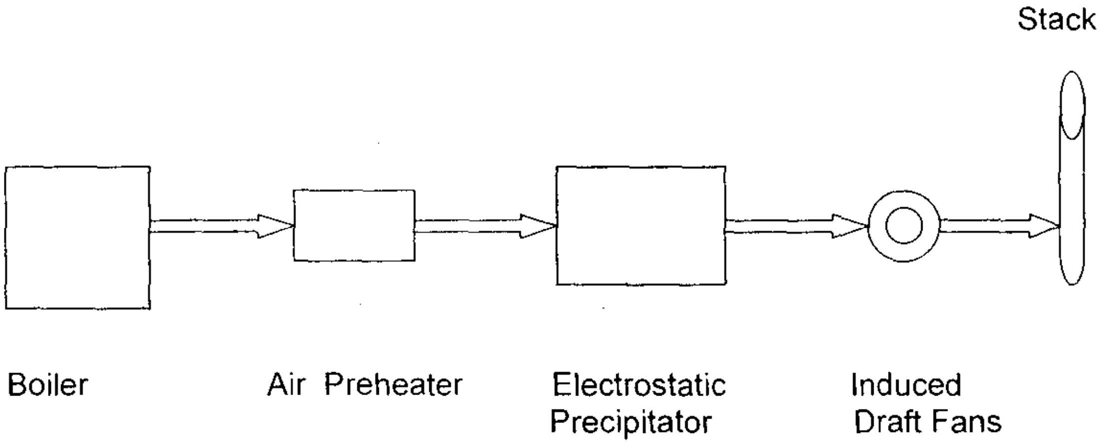
Boiler #4 is fired on 100% Wyoming Powder River Basin Coal. The boiler, air preheater and multiclone are all located inside the boilerhouse.

The exhaust gas exits the bottom of the preheater and travels approximately 15 feet down to the to the inlet of the multiclone. The exit of the multiclone is essentially a plenum on top that is situated just inside the wall of the boilerhouse. This rectangular plenum is 44 ft. in length by 12 ft. in width. The flow from it is split into two rectangular chambers, which are just outside the wall of the boilerhouse. These serve as the inlet chambers on the suction sides of the two induced-draft fans. Each is 4 ft. high by 4 ft. in width and 5 ft. in depth back to the boilerhouse. Each of the fans discharge vertically up to the inlet plenum to the elevated ESP. The rectangular ductwork from each fan at its discharge is 6 ft. wide and 4 ft. deep. The sulfur trioxide is injected into these ducts, 3 ft. downstream from each fan. The ductwork extends up from the exit of each fan for 15 ft. to the bottom of the inlet plenum of the ESP. 6 ft. above each fan, the ductwork width then gradually increases until it is 20 ft. (i.e. l/2 of the inlet plenum of the ESP).

The sulfur trioxide injection rate ranges from 10 to 20 pounds per hour, and is set by the boilerhouse control room based on the boiler's opacity monitor. No other gas conditioning is utilized. Sulfur pellets are purchased and stored at the site to be converted into sulfur trioxide for injection.

The specific collecting area of the ESP for the #4 boiler is 261 square feet per 1000 actual cubic feet per minute of exhaust gas flow.

Boiler #5



The #5 boiler is fired on 100% Wyoming Powder River Basin coal. The boiler and air preheater are both inside the boilerhouse.

The air preheater is located very close to the south wall of the boilerhouse and the exhaust gases flow 12 ft. and then split into two passages to connect to the ductwork outside the wall. Each of these horizontal passages is 25 feet in width, 12 ft. in height, and 8 ft. in length, outside of the boilerhouse. The ductwork then directs the gases 90 degrees to the east, connecting to the inlet plenum of the ESP, which directs the gases back 90 degrees to south for entry. The ductwork is 100 ft. in length in front with a depth of 8 ft. At its western edge, it is 12 ft. in height. 30 ft. downstream, this height increases to 50 ft. and remains so until its connection to the inlet plenum. The length of the opposite side of this ductwork is 43 ft. from its connection with the easternmost inlet passage.

No flue gas conditioning is conducted on this boiler.

The specific collecting area of the ESP is 244.4 square feet per 1000 actual cubic feet per minute of exhaust gases.

The dimensions presented above for these boilers are estimates based on observations, discussion with plant representatives, and information provided in previous permit applications.

#14 – Dynegy Midwest Generation (Havana)

TIER I INSPECTION MEMORANDUM

Date	May 03, 2006	Date of Inspection:			May 03, 2006
To:	E. Bakowski				
From:	R.Syed	I.D. #:	125804AAB	R/D	202

Source: Dynegy Midwest Generation Inc.

Address: 15260 North State Route 78, Havana 62644

Contact/Title: Jim Watson/Senior Engineer

Phone: 309-543-8703/309-543-3921

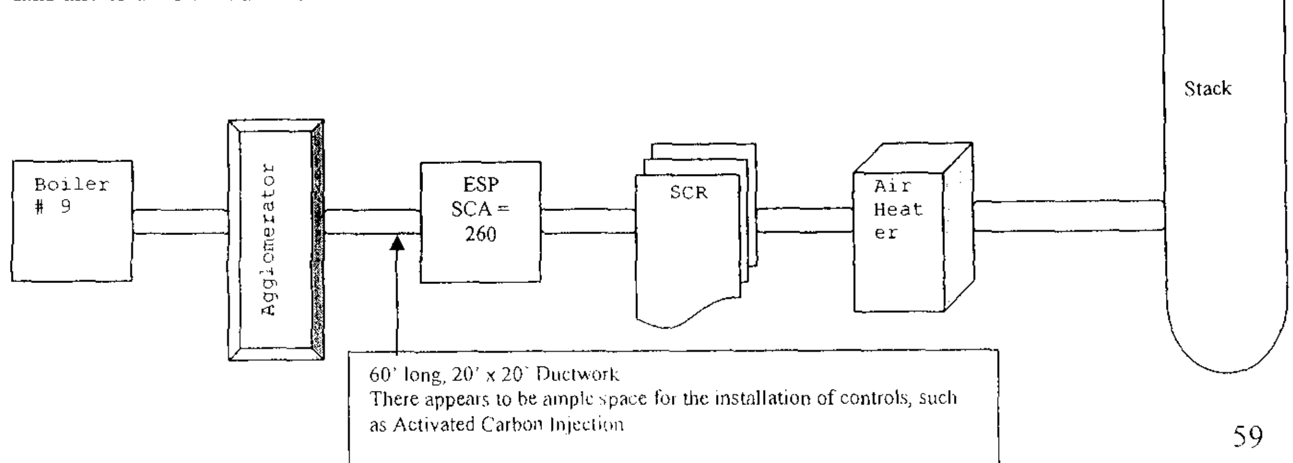
Inspector(s): Rizwan Syed/Wayne Kahila

Purpose: Coal-fired power plant equipment verification/clarification

1. Block Diagram

Unit 6 (Boiler # 9)

The ductwork between the boiler to ESP is approximately 110', out of which the agglomerator takes up about 45'. The duct is approximately 20' X 20'. Ductwork from ESP to SCR is 6' and from SCR to air heater is about 30' long and from air heater to ID fans is about 40' long. The dimensions of all the ducts are 20' X 20'. The ductwork configuration leaving from the boiler is two ducts that are identical and stays that way until right before the stack where they merge into one. The schematic is ducts from the boiler to the agglomerator to the ESP and looping down to SCR and the air heater going down to the ID fans and to the stack. ESP SCA = 260



2. SO3 injection
The facility does not use SO3 injection in the boiler.

3. Flue gas conditioning
The facility does use flue gas conditioning and is done between the boiler and the agglomerator. The flue gas additive used is manufactured by ADA and is sodium based and ADA proprietary.

4. Other Information

The Havana Power Station is located on the Illinois River approximately one mile south of Havana, Illinois. The facility has six major fossil-fuel-fired generating units, which are essentially divided into two parts.

The original plant was the first generating station built by Illinois Power. Station construction planning began in 1944 with the five units coming on-line between 1947 and 1950. These original units are steam powered by eight # 6 fuel-oil-fired boilers. # 2 fuel oil is used to ignite the # 6 fuel oil. All eight boilers are connected to a common steam header that supplies the five turbine generators, each rated at 48 MW. All eight boilers are connected to a common exhaust header, which in turn is connected to three exhaust stacks.

The second plant houses Havana Unit # 6 (Boiler # 9), which is rated at approximately 490 MW and is fired with low-sulfur pulverized coal and is wall fired. Construction began on this unit in 1975, and the unit came on-line in 1979. Coal is transported to the station either by barge or rail car where it is unloaded, stored, crushed, elevated to the coal silos in the Unit # 6 building, pulverized, and blown into the boiler for combustion. Upgrades to the existing coal handling and processing system, including a new crusher, new fly ash transport and loadout systems, flue gas conditioning system and a temporary portable coal conveying system were made and the new coal crusher and associated conveyors began operation on January 9, 2005 and achieved maximum production rates on February 1, 2005. The temporary portable coal conveying system was removed once the main conveyors began operation. Exhaust gases from the boiler pass through an electrostatic precipitator to remove fly ash and then pass through a selective catalytic reduction (SCR) unit to control NOx emissions. The facility is installing a agglomerator between the boiler and the ESP which is hot side. The agglomerator has a series of charge plates to collect small particles to attract to each other and assist in enhancing the efficiency of the ESP. The agglomerator by itself is not an emission source or a control equipment. According to the Dynegy staff, the Agency's office in Springfield was notified about this installation. From the SCR, the exhaust gas flows through the air heater then up the stack Prior to installation of the SCR over-fire air fans were installed and began operation on March 03, 2003 to provide some NOx control. The SCR system began operation on August 04, 2003. The boiler has started burning low-sulfur sub bituminous coal in place of low-sulfur bituminous coal on January 19, 2005.

Presently, about 12 startups of Unit # 6 occur per year. Dynegy has changed the station's operating status to a base load unit. Prior to the change, about 150 startups per year occurred.

Emissions Unit Information

Emission Unit	Description	Emission Control Equipment
Boiler 9	Babcock & Wilcox Radiant Coal-Fired Boiler 447 MW Nominal Rating (1978). (pulverized coal wall fired)	Overfire Air System, Low NOx burners, In-duct Selective Catalytic Reduction System and ESP with Flue Gas Conditioning

#15 – Dynegy Midwest Generation (Hennepin)

Division of Air Pollution Control – Field Operations Section

ID# 155 010 AAA
Dynegy Midwest Gen.
Field Inspection Report

Special Inspection Memorandum

Date: May 4, 2006 (revised) **Date of Inspection:** April 28,2006

To: E. Bakowski **Last Inspection:** not relevant

From: J. Krolak & W. Kahila **ID:** 155 010 AAA **R/D:** 203

County: Putnam **SIC:** 4911

Source: Dynegy Midwest Generation, Inc.
Address: R.R.1, Box 200A, Hennepin, IL 61327

Contact: Jim Dodson **Title:** Plant Manager
Phone: 815-339-9212 **Fax:**

Contact: John Augspols **Title:** Environmental Coordinator
Phone: 815-339-9218 **Fax:** 815-339-2772

Contact: Michelle Chestnut **Title:** Environmental Specialist (Decatur)
Phone: 217-872-2367 **Fax:** 217-876-7475
Cell: 217-714-4794

Description: This facility is a coal-fired electric generating station that now burns western sub-bituminous low-sulfur coal to meet federal acid-rain prevention requirements. Dynegy Midwest is the successor (for fossil-fuel power generation) to Illinois Power Company.

1. <u>Block Diagram</u>

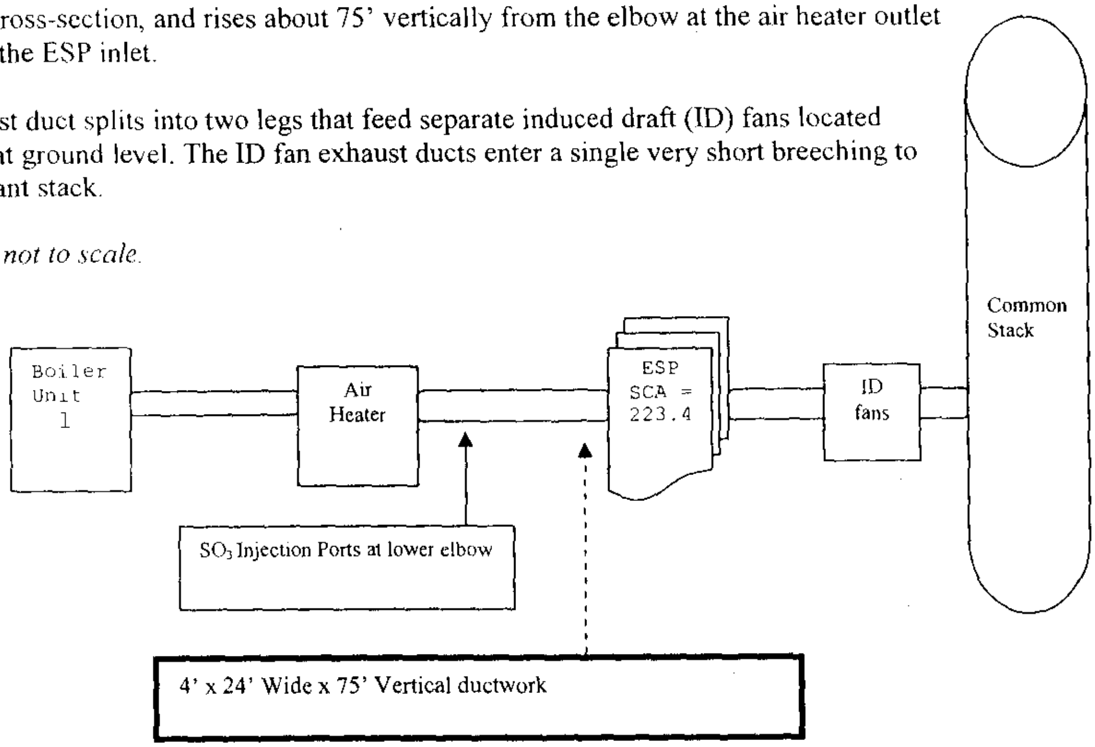
Unit 1

The Unit 1 boiler is a single furnace with two forced draft (FD) fans, pulverized coal firing, a tubular air heater, an electrostatic precipitator (ESP) and two induced draft (ID) fans.

The ductwork between the Air Heater and cold-side ESP is approximately 4' by 24', rectangular in cross-section, and rises about 75' vertically from the elbow at the air heater outlet to the elbow at the ESP inlet.

The ESP exhaust duct splits into two legs that feed separate induced draft (ID) fans located under the ESP at ground level. The ID fan exhaust ducts enter a single very short breeching to the common plant stack.

The diagram is not to scale.



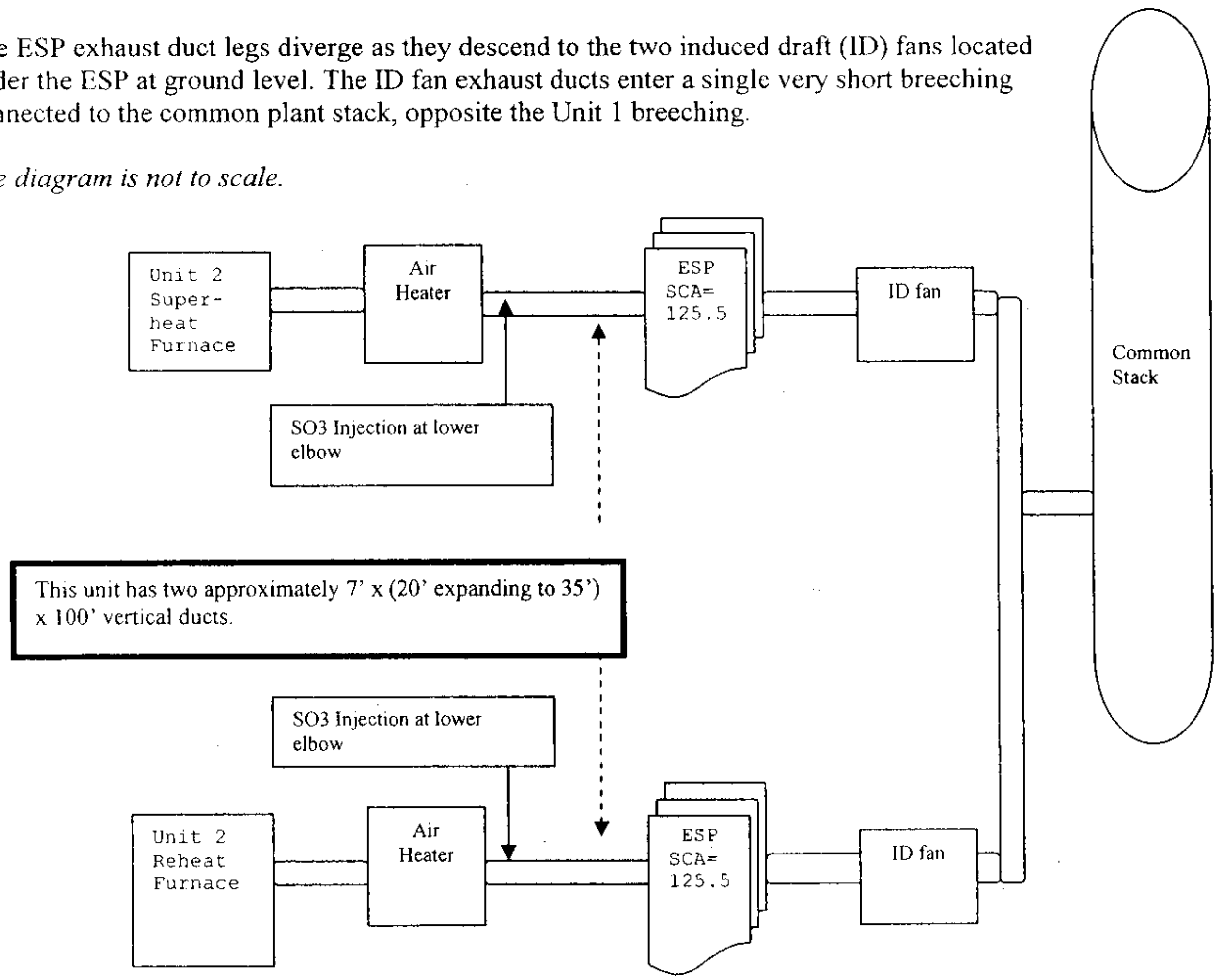
Unit 2

This unit consists of two separate steam-generating furnaces, one containing the high-pressure superheater and the other containing the reheat superheater. Each furnace has its own FD fan, recuperative air heater, exhaust duct to the ESP, and ID fan.

The ducts between each air heater and the conjoined cold-side ESP are approximately 7' front-to-back, expanding from about 20' to 35' wide as they rise about 100' to the ESP inlet. There are right-angle elbows at the bottom (entry) and top (exit) of these ducts.

The ESP exhaust duct legs diverge as they descend to the two induced draft (ID) fans located under the ESP at ground level. The ID fan exhaust ducts enter a single very short breeching connected to the common plant stack, opposite the Unit 1 breeching.

The diagram is not to scale.



2. SO$_3$ Injection

Dynegy's Hennepin Station burns only low-sulfur Powder River Basin (PRB) coal, and uses SO$_3$ injection after the air heater exhaust to enable the ESPs to function properly. The sulfur use rate and resultant SO$_3$ concentration are not directly measured; the optimum concentration is dependant on exhaust gas parameters and is determined by observing the ESP power levels and the plume opacity and appearance. Inadequate SO$_3$ results in excess emissions and opacity, while a slightly bluish plume indicates too much SO$_3$.

3. Flue gas conditioning

No other flue gas conditioning is utilized beyond the furnace NO$_x$ controls.

4. Other Information

The station is located in an agricultural/ industrial area within the corporate limits of Hennepin in Putnam County, and is an electric utility. The two coal- or natural gas-fired units at this station are capable of generating a total of about 316 megawatts. No other commercial generating units are located here.

Under Board Regulations, the station's combined SO$_2$ emission limit is 17,050lbs/hr due to the 264foot stack height. Burning PRB coal, actual emissions do not approach this limit.

The station is located on the south bank of the Illinois River, and coal is delivered to the site by barges.

Construction of Unit 1 was begun about 1950, followed by the larger Unit 2 about 1956. Due to the lack of space at the site, the ESPs for both units are located above the respective ID fans, with the common stack between them. Unit 2's ESP is located higher above the ID fans to allow space for the larger ductwork and breeching underneath it.

When considering how to reduce sulfur emissions to meet acid rain restrictions, the owner (formerly Illinois Power Company) determined that it was not economically feasible to install additional flue-gas control systems such as scrubbers, or to increase the size of the ESPs. The only means left was the use of low-sulfur coal and SO$_3$ injection.

It is apparent that emission control systems requiring enlarged or additional structures could not be fitted between the furnaces and the river. Lateral expansion might be accommodated, probably at a considerable expense.

The Unit 2 ESP was refurbished in 2003, as described in Dynegy's letter of January 29, 2003 to Don Sutton of the Agency. The Collection Plate Area and SCA information on form 260-CAAPP, page 164 of the original CAAPP application submitted in September 1995, is no longer correct. Information received from Dynegy on May 4, 2006 states that the collection plate area is now 109,200sq ft, and the Specific collector Area (SCA) is 125.5.

CC: Dean Hayden
Wayne Kahila

#16 – Dynegy Midwest Generation (Vermilion)

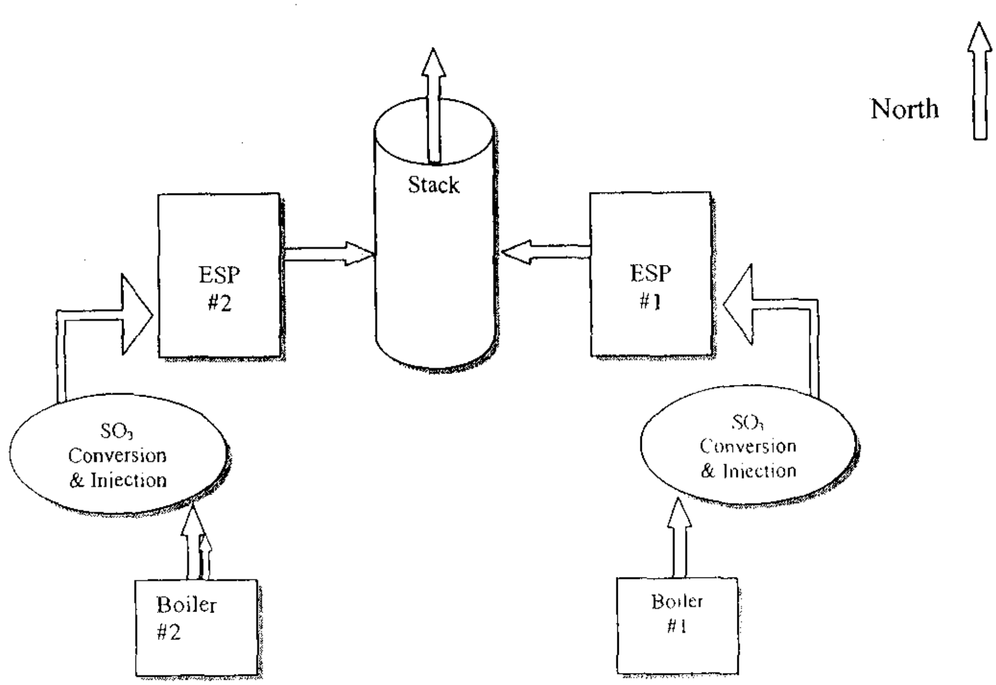
Source:	Dynegy Midwest Generation, Inc.
ID:	183 814 AAA
Address:	County Road 2150, Oakwood / Vermilion County
Phone:	(217) 354-2141
Inspector:	R. Stortzum

1. Block Diagram
Units #1 and #2 (present)

The rectangular ductwork between Boiler #1 and ESP #1 is approximately 30 feet of horizontal and 50 feet of vertical. The rectangular ductwork between Boiler #2 and ESP #2 is approximately 30 feet of horizontal and 50 feet of vertical. The SO_3 injection ports (8) are located in the bottom of the rectangular vertical inlet ducts to each ESP and SO_3 mixes well with the flue gas before entering the ESP. Each ESP exhaust has rectangular ductwork entering the base of the chimney (180° apart) and flue gas from both boilers then exits the one (1) chimney (stack).

Boiler #1 has a rotating opposed fire air (ROFA) system for NO_x emission reduction. This system also allows for urea solution injection to react with combustion gases to minimize the formation of NO_x and is normally only used during the ozone season. The boiler unit has a lower air heater to heat combustion air and lower the gas temperature to the ESP. ESP SCA = 157

Boiler #2 has been equipped with over-fire air and low NO_x burner (LNB) systems to reduce NO_x emissions. The boiler unit has a lower air heater to heat combustion air and lower the gas temperature to the ESP. ESP SCA = 182



2. Block Diagram
Units #1 and #2 (in operation by June 2007)

Dynegy has submitted construction permit application PN06030002 for mercury / PM emission reduction and Dynegy personnel explained there is not enough space to install the baghouse and carbon sorbent injection system in the plant area near the ESP's and chimney (stack). The baghouse and carbon silo will be constructed near the north / northwest side of Unit 2. Baghouse inlet ductwork will be constructed from the outlet of each ESP and combined into a single shared duct with carbon sorbent injected into the flue gas before entering the baghouse. The baghouse exhaust ductwork will be constructed to connect back to the existing chimney ducts (2).

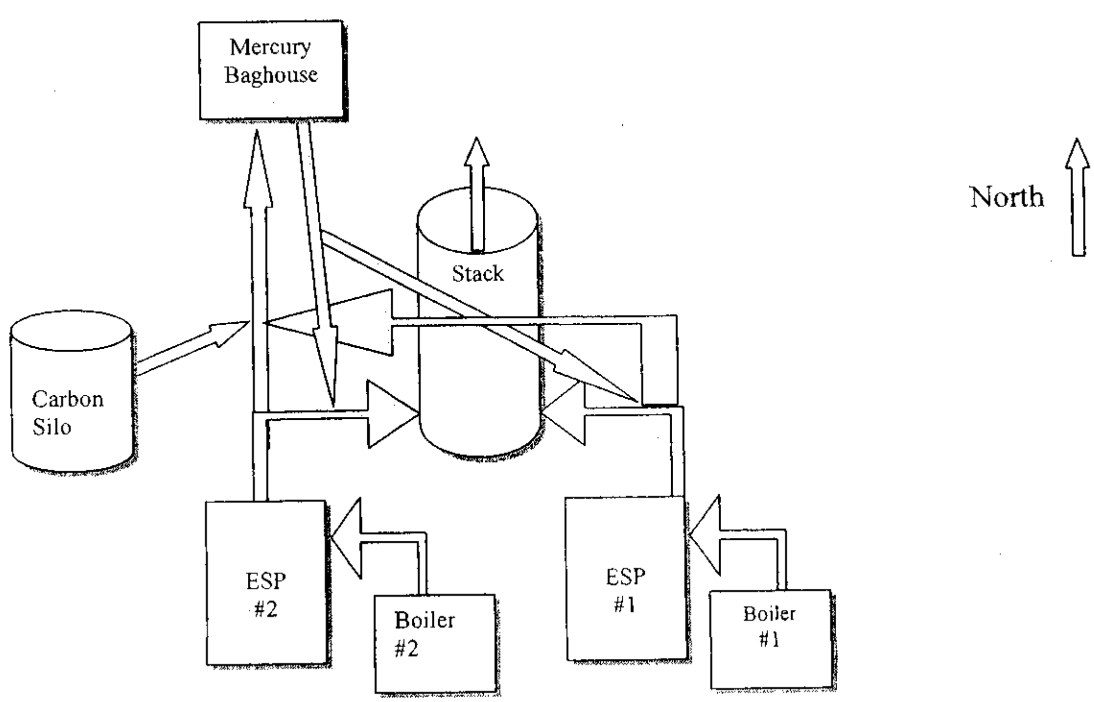
Dynegy has indicated in permit application PN06030002 and through an e-mail on May 5, 2006 that the SO_3 injection system will not be removed when the baghouse / sorbent injection system is constructed and in operation but will be operated at Dynegy's discretion as needed to comply with the applicable permit condition requirements.

Approximate distance between ESP outlet and shared duct for baghouse unit:
- Unit 1..... 120 feet
- Unit 2....... 20 feet

Size of shared duct: 18 feet x 12 feet x 140 feet

Approximate distance from baghouse outlet to chimney inlet:
- Unit 1..... 100 feet
- Unit 2....... 40 feet

Common duct, baghouse outlet to chimney (stack): 80 feet



3. SO_3 Injection:
The facility presently utilizes SO_3 injection, however, the system may or may not be utilized in conjunction with new mercury/PM baghouse control.

4. Flu Gas Conditioning:
The plant previously tried flue gas conditioning when using high sulfur coal. The boilers have been switched to Powder River Basin coal (PRB) and this system will no longer be used.

5. General Boiler Description:

3.2 Unit #1 Boiler with ESP and low NOX combination system

Dynegy has two Combustion Engineering tangentially fired pulverized coal boilers (Units #1 and #2). Unit #1 has a maximum rated capacity of 84 MW (785 mmbtu/hr). Each Unit has 4 pulverizers and 16 burners. Each pulverizer feeds 4 burners that are located at each corner of the boiler. The pulverized coal is injected at four levels of the boiler. Each pulverizer corresponds to a different height at which coal is injected into the boiler. The emissions from each unit are exhausted through an electrostatic precipitator and then through a common stack.

Electrostatic precipitators (ESP) control the particulate matter emissions from the boilers. The ESP for Unit #1 is a Buell with 4 sections (4 TRs). The ESPs uses a hammer/anvil type rapper to remove particulate matter from the plates. Particulate matter emissions from Unit 1 are limited to 0.12 lbs/mmbtu per 35 Ill. Adm. Code 212.203(b).

Sulfur dioxide (SO_2) emissions from Units #1 are uncontrolled. SO_2 emissions are limited to 8.5 lb/mmbtu by 35 Ill. Adm. Code 214.184. In addition, SO_2 emissions from both units #1 and #2 are limited to 16,805 lbs/hr by permit special condition. Construction permit PN05030030 was granted 4/6/05 to install new SO_3 gas conditioning system for ESP unit to burn low-sulfur coal (PRB) and reduce PM and SO_2 emissions. SO_3 concentration in the flue gas will be approximately 20 ppm as needed by volume.

Carbon monoxide emissions from the boilers are subject to 35 Ill. Adm. Code 216.121 (200 ppm corrected to 50 percent excess air).

Dynegy has SO_2, NOX, CO_2, flow and opacity continuous emissions monitors (CEM/COM) located in the stack. Dynegy installed these monitors because of the Acid Rain regulations, 40 CFR Part 75. However, Dynegy is required by permit special condition to submit quarterly reports of excess opacity and SO_2.

Unit #1 and its ESP are permitted in CAAPP operating permit 95090050 and state operating permit 73020064.

3.3 Unit #2 Boiler with ESP and low NOX combination system

Dynegy has two Combustion Engineering tangentially fired pulverized coal boilers (Units #1 and #2). Unit #2 has a maximum rated capacity of 113 MW (1,167 mmbtu/hr). Each Unit has 4 pulverizers and 16 burners. Each pulverizer feeds 4 burners that are located at each corner of the boiler. The pulverized coal is injected at four levels of the boiler. Each pulverizer corresponds to a different height at which coal is injected into the boiler. Unit #2 is equipped with low NOx burners, installed in 1993. The burners take a portion of the airflow that is injected into the bottom and injects the air above the highest burner. The emissions from each unit are exhausted through an electrostatic precipitator and then through a common stack.

Electrostatic precipitators (ESP) control the particulate matter emissions from the boilers. The ESP for Unit #2 the ESP is a Western-Precipitation with 10 sections (5 TR=s). The ESPs uses a hammer/anvil type rapper to remove particulate matter from the plates.

Particulate matter emissions from Unit 2 are limited to 0.1 lbs/mmbtu per 35 Ill. Adm. Code 212.202.

Sulfur dioxide (SO_2) emissions from Unit #2 are uncontrolled. SO_2 emissions are limited to 8.5 lb/mmbtu by 35 Ill. Adm. Code 214.184. In addition, SO_2 emissions from both units #1 and #2 are limited to 16,805 lbs/hr by permit special condition. Construction permit PN05030030 was granted 4/6/05 to install new SO_3 gas conditioning systems for ESP unit to burn low-sulfur coal (PRB) and reduce PM and SO_2 emissions. SO_3 concentration in the flue gas will be approximately 20 ppm as needed by volume.

Carbon monoxide emissions from the boilers are subject to 35 Ill. Adm. Code 216.121 (200 ppm corrected to 50 percent excess air).

Dynegy has SO_2, NOX, CO_2, flow and opacity continuous emissions monitors (CEM/COM) located in the stack. Dynegy installed these monitors because of the Acid Rain regulations, 40 CFR Part 75. However, Dynegy is required by permit special condition to submit quarterly reports of excess opacity and SO_2.

Unit #2 and its ESP are permitted in CAAPP operating permit 95090050 and state operating permit 73020063/construction permit PN05030030.

6. The information concerning ductwork dimensions was received from Dynegy personnel (Rick Dieriex) and is not listed or documented in any permit application or official Dynegy drawing. The actual layout of the new construction of mercury baghouse, associated ductwork, and auxiliary equipment may not be as presented by FOS in this document. The drawings are not to scale.

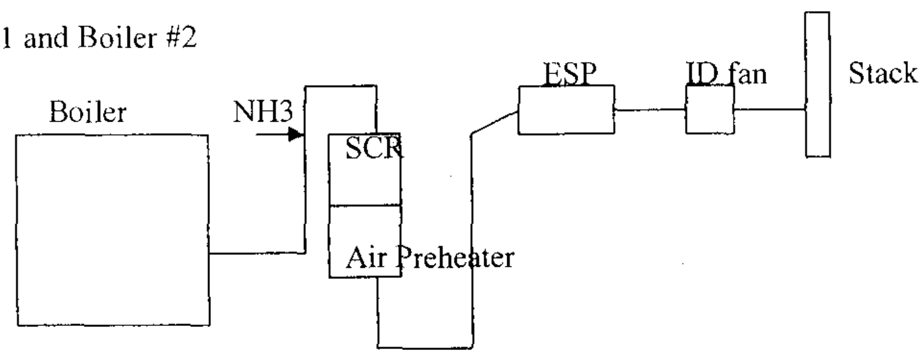
#17 – Dynegy Midwest Generation (Baldwin)

Source: Dynegy Midwest Generation, Inc.
I.D. #157851AAA
Address: P.O. Box 146, Rural Baldwin, Baldwin, IL 62217
Contact/Title: Rick Diericx/Environmental & Bill Portz/Supervisor
Phone: plant-618-785-2294 & corporate-217-872-2354
Inspectors: Mark Schlueter & Jeff Benbenek
Date of Verification: May 2, 2006

There are 3 coal fired boilers/units at Baldwin. Boiler #1 and Boiler #2 are identical. Both Boiler #1 and Boiler #2 are fired on 100% Wyoming Powder River Basin Coal.

The diagram included is a side view of the equipment & ductwork as it leaves the boiler. The exhaust gases exit the bottom of the boiler through the economizer and travels 10 feet before turning upward and traveling vertically. The gas stream is split into two rectangular ducts (each sized 16 ft by 24 ft)

Boiler #1 and Boiler #2

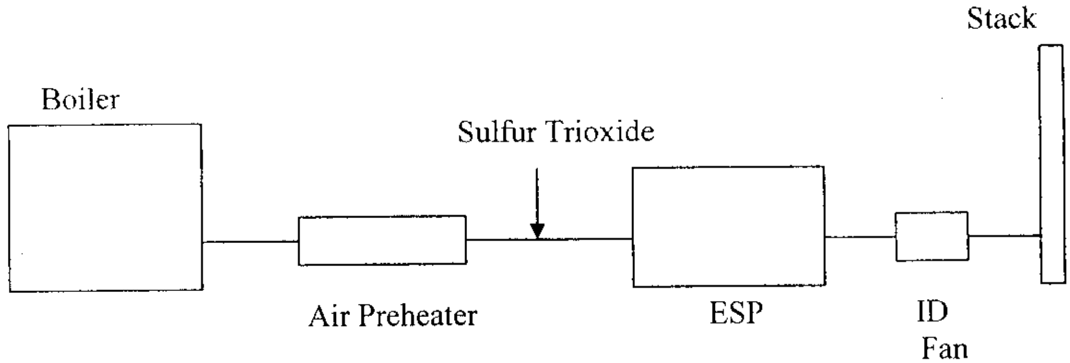


The two ducts (16 x 24) travel about 12 ft and then bend away from each other slightly for about 6 ft. The two ducts then straighten and head up (vertically) about 26 ft where the gas stream is injected with ammonia (NH3) before turning and heading down vertically to the SCR & Air Preheater. There is no discernable distance between the SCR and the Air Preheater.

Coming down out of the Air Preheater the gases turn immediately and head horizontally in spit streams again. The two ducts (12ft x 27ft) only travel about 4 ft before turning upward and heading vertically a distance of about 40 ft. At this point the ductwork expands gradually about 20 ft as the gas stream now angles in vertically, traveling about 12 more feet and enters the inlet plenum of the ESP.

Boiler #3

Boiler #3 is also fired on 100% Wyoming Powder River Basin Coal. Boilers #1 & #2 are cyclone burner type units and had to have SCR type controlled installed to meet air emission limits. Boiler #3 is not a cyclone type, but the coal is fed tangentially, which creates a cooler fireball. This unit does not need to go the route of an SCR. The only gas conditioning performed at Boiler #3 is sulfur trioxide (SO3) injection.



The gases come out of the Air Preheater and immediately are injected with sulfur trioxide. The gas stream has been split into two rectangular ducts, each is 12 ft high and 42 ft across. Each duct has 8 ports where the sulfur trioxide is injected.

After injection the flue gases travel about 20 ft before the ductwork begins to transition from a width of 2 x 42 or 84 ft to 96 ft. The gases travel about 30 ft during this transition. After the duct reaches its width of about 96 ft, the gases enter the inlet plenum of the ESP.

The sulfur trioxide injection rate produces a SO3 concentration of 7-10 ppm. Sulfur is purchased in the form of pellets and is burned at a rate of 60-100 lb/hr. to produce the required SO3. The rate is set by the operator in the boilerhouse control room.

The dimensions presented for the three Boilers and associated equipment at Baldwin are estimates based on observations, discussions with company personnel and information provided in previous permit applications.

As of 1:00 pm on 5/4/06, the company has yet to provide the Specific Collection Area of the ESP of the 3 Boilers. Mr. Diericx sent an e-mail to Mark Schlueter's attention, stating that the company was still attempting to verify the exact collection area. This information was requested at the May 2nd visit.

#18 – Kincaid Generation (Kincaid)

TIER I INSPECTION MEMORANDUM

Date May 2, 2006 Date of Inspection: May 1, 2006

To: E. Bakowski

From: E. Kierbach I.D. #: 021814AAB R/D 204

Source: Kincaid Generation, L.L.C.

Address: PO Box 260: 4 miles west of Kincaid Rt. 104 Kincaid, Il 62540

Contact/Title: Anu Singh, PE/Sr. Environmental Compliance Engineer

Phone: 217-237-4311 x 2291 / 217-237-5519

Inspector(s): Steve Youngblut/Ernie Kierbach

Purpose: Coal-fired power plant equipment verification/clarification

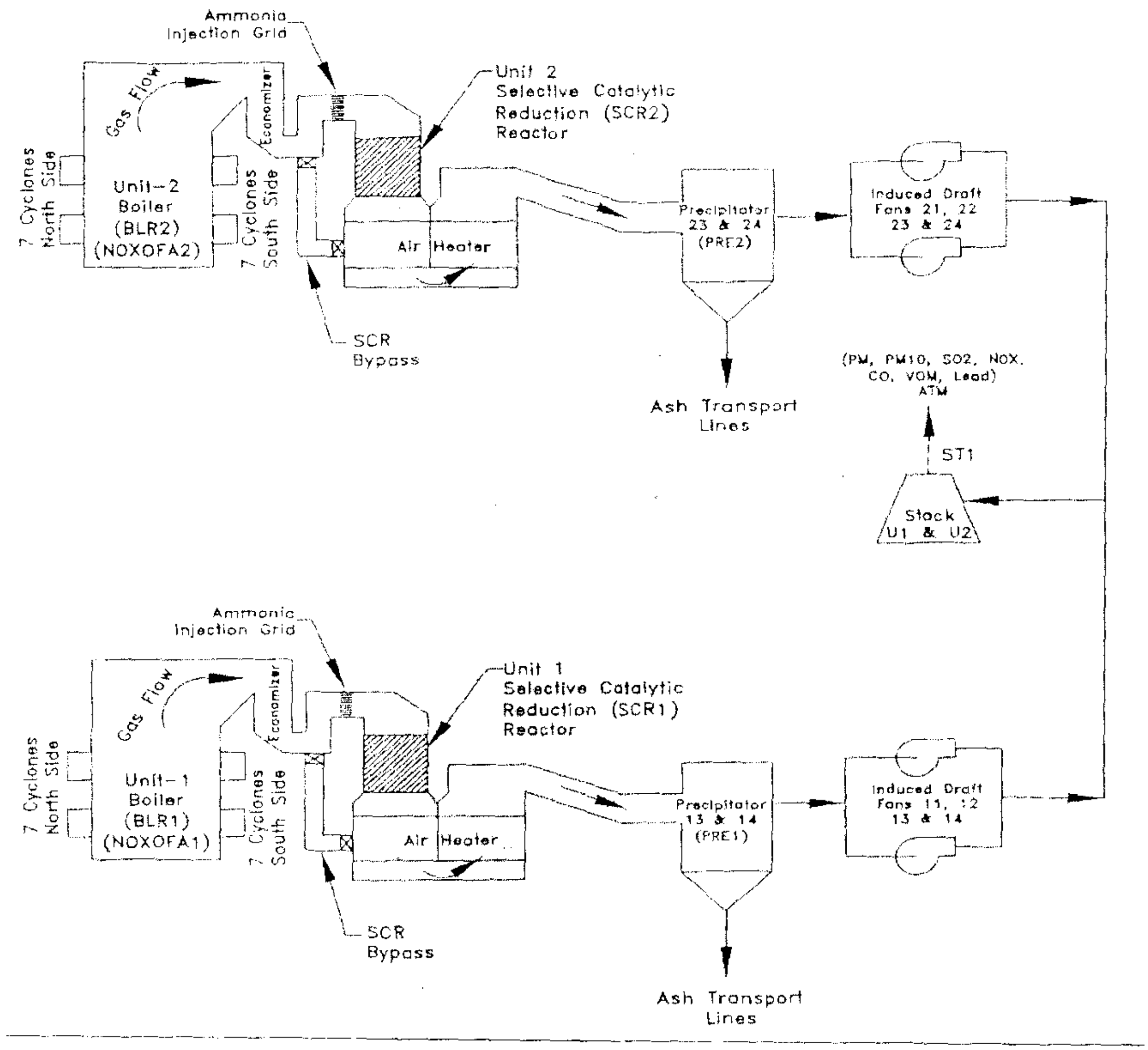
1. Block Diagram

The block diagram depicts boilers unit 1 and 2 along with ductwork and controls.

Unit 1 boiler is equipped with over fire air for NOx reduction. The unit exhausts to an ammonia injection selective catalytic reduction system (SCR). From the SCR exhaust travels thru an air heater to an electrostatic precipitator (ESP). The ESP has two main compartments each with a specific collection area (SCA) of 327.5. From the ESP the exhaust travels to a common stack.

Unit 2 boiler is equipped with over fire air for NOx reduction. The unit exhausts to an ammonia injection selective catalytic reduction system (SCR). From the SCR exhaust travels thru an air heater to an electrostatic precipitator (ESP). The ESP has two main compartments each with a specific collection area (SCA) of 327.5. From the ESP the exhaust travels to a common stack.

In either configuration the estimated distance from the air heater discharge to the ESP is 325 feet. There would appear to be ample room for add on control in this section of ductwork.



Ammonia Injection Grid
Unit 2 Selective Catalytic Reduction (SCR2) Reactor
Gas Flow
Economizer
7 Cyclones North Side
Unit-2 Boiler (BLR2) (NOXOFA2)
7 Cyclones South Side
Air Heater
SCR Bypass
Precipitator 23 & 24 (PRE2)
Induced Draft Fans 21, 22 23 & 24
Ash Transport Lines
(PM, PM10, SO2, NOX, CO, VOM, Lead) ATM
ST1
Stack U1 & U2
Ammonia Injection Grid
Unit 1 Selective Catalytic Reduction (SCR1) Reactor
Gas Flow
Economizer
7 Cyclones North Side
Unit-1 Boiler (BLR1) (NOXOFA1)
7 Cyclones South Side
Air Heater
SCR Bypass
Precipitator 13 & 14 (PRE1)
Induced Draft Fans 11, 12 13 & 14
Ash Transport Lines

2. SO3 injection

The facility does not use SO3 injection. A SO3 injection has never been used at the facility.

3. Flue gas conditioning

No flue gas conditioning is utilized.

4. Other Information

Kincaid Generation utilizes two coal-fired boilers in conjunction with steam turbine generators to generate electricity. Electricity generated by Kincaid Generation is sold on the "grid". Coal combusted at this facility is low sulfur Powder River Basin coal (Black Thunder, North Antelope, and Antelope).

The facility, in general, consists of coal receiving/storage, coal processing/crushing systems, a water treatment plant, an auxiliary boiler, and two coal-fired units each controlled by an SCR and electrostatic precipitator (ESP) vented to a common stack.

Each boiler is also equipped with an over fire air system (OFA) to reduce emissions of NO_x to aid in complying with the Acid Rain Program requirements of 40 CFR 76. In general, this is accomplished by reducing airflow (oxygen) in the furnace region resulting in a reduction of NO_x formation.

Additionally, the facility has installed a selective catalytic reduction (SCR) system to each unit. The SCR taps in at the economizer exit and vents to the air heater. The air heater section then vents to the ESP. The SCR systems provide NO_x reductions during the ozone season. The SCR systems will utilize ammonia as a reducing agent to convert nitrogen oxide emissions from the combustion process to nitrogen and water.

Steam from each boiler is fed to a turbine set. A turbine set consists of one high-pressure turbine, one intermediate-pressure turbine, and two low-pressure turbines. The turbine sets are connected to generators that complete the conversion of chemical energy to electric power.

Emissions Unit Information

Unit	Manufacturer	Firing Type	Design Heat Input	Control Equipment	Date Constructed
Unit 1	Babcock & Wilcox	Cyclone	6,634 mmbtu/hr	OFA, SCR, ESP	1967
Unit 2	Babcock & Wilcox	Cyclone	6,406 mmbtu/hr	OFA, SCR, ESP	1968
Aux Unit	Babcock & Wilcox	-	165 mmbtu/hr	-	1984

#19 – Electric Energy (Joppa)

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
Division of Air Pollution Control--Field Operations Section

TIER II MEMORANDUM

Date: February 27, 2006
To: Ed Bakowski, FOS Manager
From: Scott Arnold, FOS

Date of Inspection: February 9, 2006
Last Insp. Date: February 15, 2005
I.D.#: 127 855 AAC **R/D:** 304
County: Massac **SIC:** 4911

Source: Electric Energy, Inc.
Address: Joppa Steam Station, 2100 Portland Rd., Joppa, IL 62953
Contact/Title: Bruce Parker, Environment Engineer
Phone: 618/543-7531, Ext.: 458
Fax: 618/543-7420

Purpose:

FY06 Workplan Inspection. Also witnessed RATA.

Description:

Electric Energy's - Joppa Generating Station, located near Joppa, Illinois consists of six coal-fired generating units, which supply electricity for the U.S. DOE - Paducah, Kentucky uranium enrichment facility, as well as supply the grid. The facility is a CAAPP source.

Units 1-6 are all Combustion Engineering pulverized coal-fired units rated at 181 MW (1653 mmbtu/hr) capacity. The units started operation between 1953 and 1955. The units are each equipped with Research - Cottrell 5 section (3 TR's) ESP's installed in 1971 and 1972. The ESP's were upgraded in 1993-94 to handle particulate emission from western coal. The units are vented through three 525' stacks, two units per stack. Continuous emission monitoring equipment was installed at the station, as per 1990 Clean Air Act amendment.

The station receives western coal by rail from the Powder River Basin in Wyoming with less than 1% sulfur. The facility burns approximately 4.6×10^6 tons of coal per year.

Following is a summary of station design data:

Unit	MW	MMBTU/hr	Type	Age	Equipment	Age	Height
1	181	1653	C-E, P-C	1953	R-C, ESP	1971	525
2	181	1653	C-E, P-C	1953	R-C, ESP	1972	
3	181	1653	C-E, P-C	1954	R-C, ESP	1972	525
4	181	1653	C-E, P-C	1954	R-C, ESP	1972	
5	181	1653	C-E, P-C	1955	R-C, ESP	1972	525
6	181	1653	C-E, P-C	1955	R-C, ESP	1972	

The station's SO_2 limit is 38,865 lb/hr. based on a 3-hour block average.

Findings

I arrived at Electric Energy, Inc. at roughly 10:25 a.m. on the date of inspection. I met with Bruce Parker, Environmental Engineer, and Mike Mercer, Chemist. We began the inspection with a walk through of the facility. On this day, a gas RATA was being finished up on the SO_x, NO_x and CO_2 monitors on all three stacks. They were presently on stack #3, units #5 and #6. Unit #6 was operating at roughly 180 MW. Unit #5 was in start up running at about 100 MW. After Unit #5 reached 180 MW, stack #3 would undergo its' RATA. The RATAs on stacks #1 and #2 were done yesterday with both operating at 360 MW. All the boilers operate at about 180 MW or high load normally, and there are two units vented to each stack.

The RATA was finished yesterday on stacks #1 and #2, Unit #1 and #2 and Units #3 and #4. The RATA was being done by G.E. Mostardi Platt. The stack testing crew chief was Greg Rock. Mr. Rock told me they were doing Methods 6C, 7E and 3A for SO_x, NO_x and CO_2, respectively. Mr. Rock said they were using a dilution extraction system for testing, since Electric Energy, Inc. has the same type CEM system. They were sampling 3 pts., 7 minutes/pt. For 21 minute RATA runs. They were using a Teflon probe. They were doing a minimum of 9 runs on each stack at high load, which is also normal operating conditions.

We next checked out the coal handling system. I observed the dumping of a train. I noted little, if any, opacity. Ron Thompson, the coal-handling supervisor stated that the coal being dumped on this day was going to storage. The #25 stacker was the only one operating. Stackers #23 and #24 were down at this time. I noted opacity in the 5% range from the #25 stacker. I noted no other VE from the storage area or coal piles.

We proceeded to the control room. All units were operating at full load or about 180 MW each, except the #5 unit which was operating at 100 MW and in start up mode. I asked for an received a copy of the CEM data for each stack (attached).

We returned to the office and Mr. Parker provided me with a copy of the "used oil disposal log" (copy) and the "used oil" analysis (copy in general file).

I next asked for coal burned in 2005 (attached). I also asked if any chemical waste had been burned in 2005. Mr. Parker stated there had. There is a chemical waste quantity and analysis in the company's general file. They burned roughly 15,000 gallons of chemical cleaning waste in 2005.

Finally, I asked for and received a copy of 2004 and 2005 emissions (attached).

This completed this inspection. Recommendations will be made.

SAA:jkb/233a/02-28-06

cc: BOA/Marion
Electric Energy, Inc.

Conclusions & Recommendations

The company appears to be in compliance with Agency regulations. Also, I photographed all three stacks. There is no equipment after the ESP and before the stack. All three ESPs are cold side ESP's.

SAA:jkb/233a/02-28-06

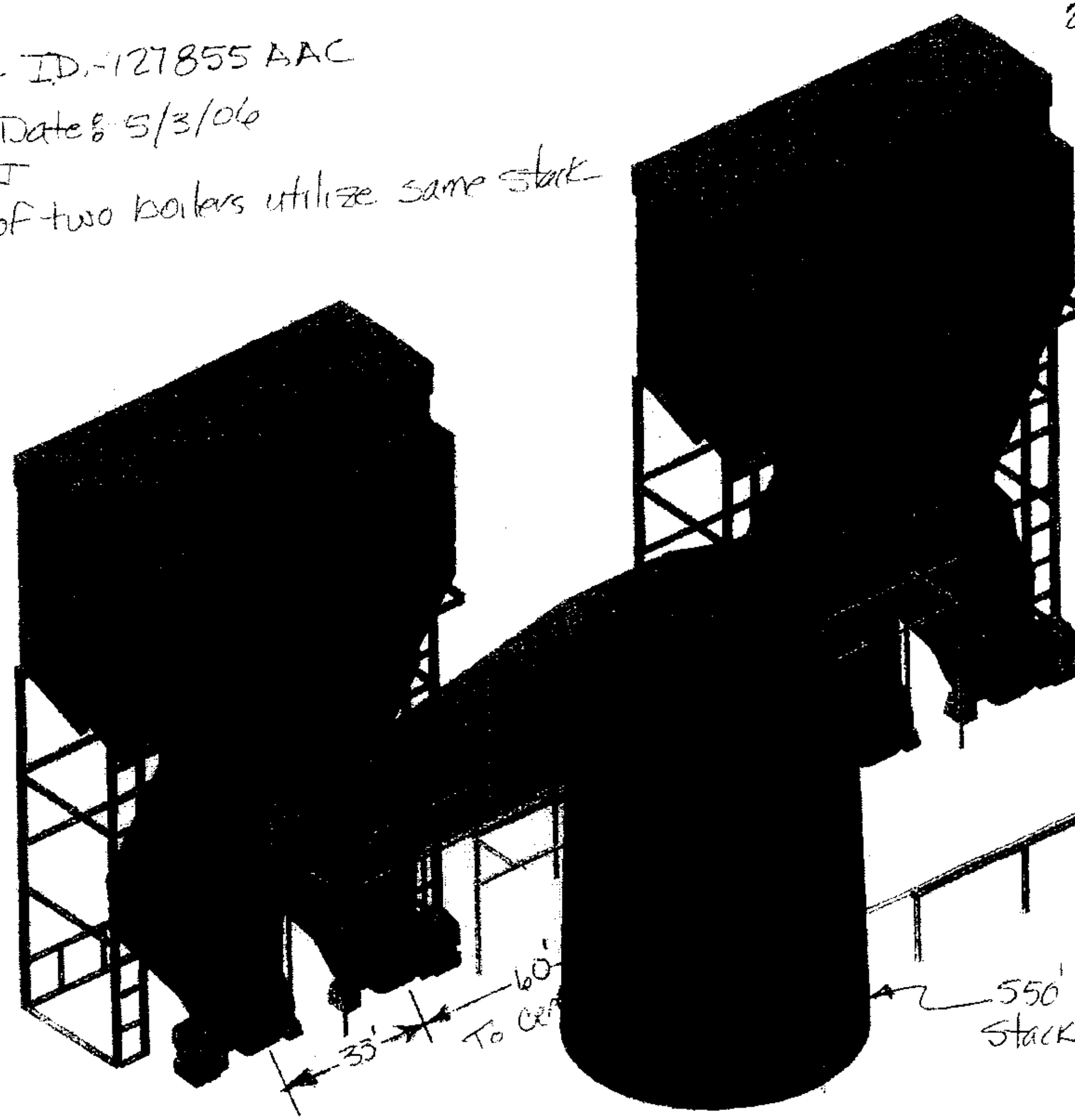
cc: BOA-Marion

EEI-ID.-127855 AAC

Visit Date: 5/3/06

JBJ

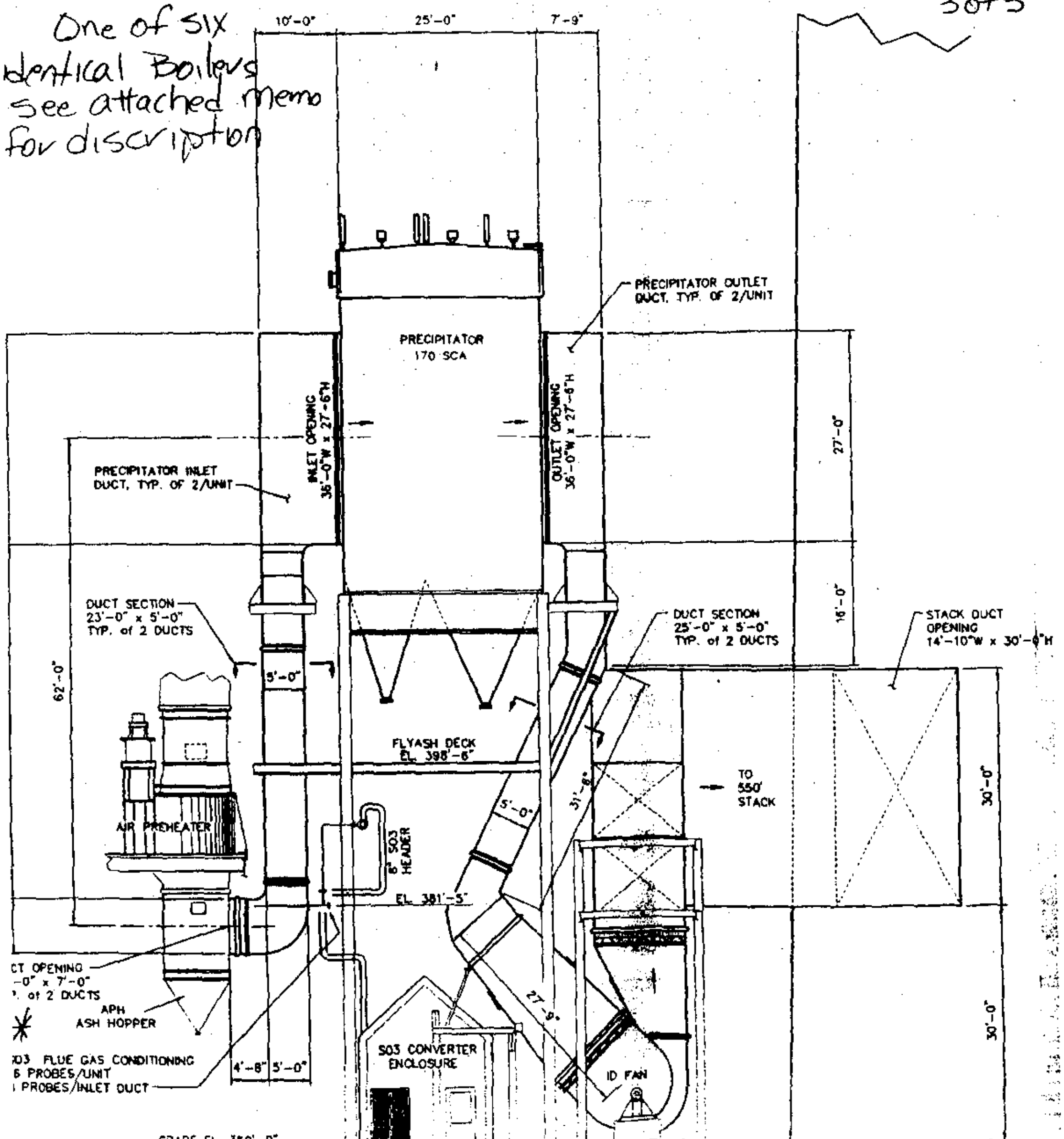
Each of two boilers utilize same stack



EEI - I.D. - 127855AAC Visit Date: 5/3/06 JBJ

3 of 3

One of six identical Boilers see attached memo for discription



* SO_3 conditioning used to maintain average SO_3 concentration of 6PPM in flue gas

#20 - City of Springfield (CWLP)

TIER I INSPECTION MEMORANDUM

Date April 28, 2006 Date of Inspection: April 27, 2006

To: E. Bakowski

From: E. Kierbach I.D. #: 167120AAO R/D 204

Source: City Water, Light, & Power

Address: 3100 Stevenson Drive, Springfield 62707

Contact/Title: PJ Becker/Environmental

Phone: 217-757-8610/217-757-8615

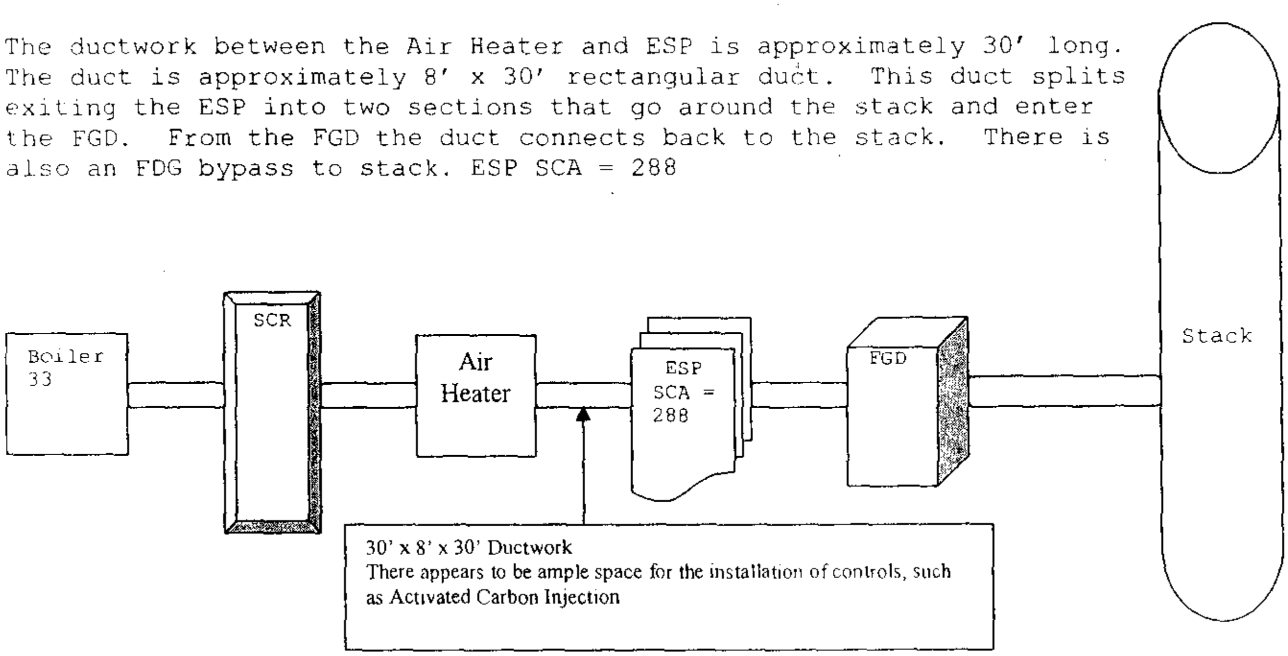
Inspector(s): Steve Youngblut/Ernie Kierbach

Purpose: Coal-fired power plant equipment verification/clarification

1. Block Diagram

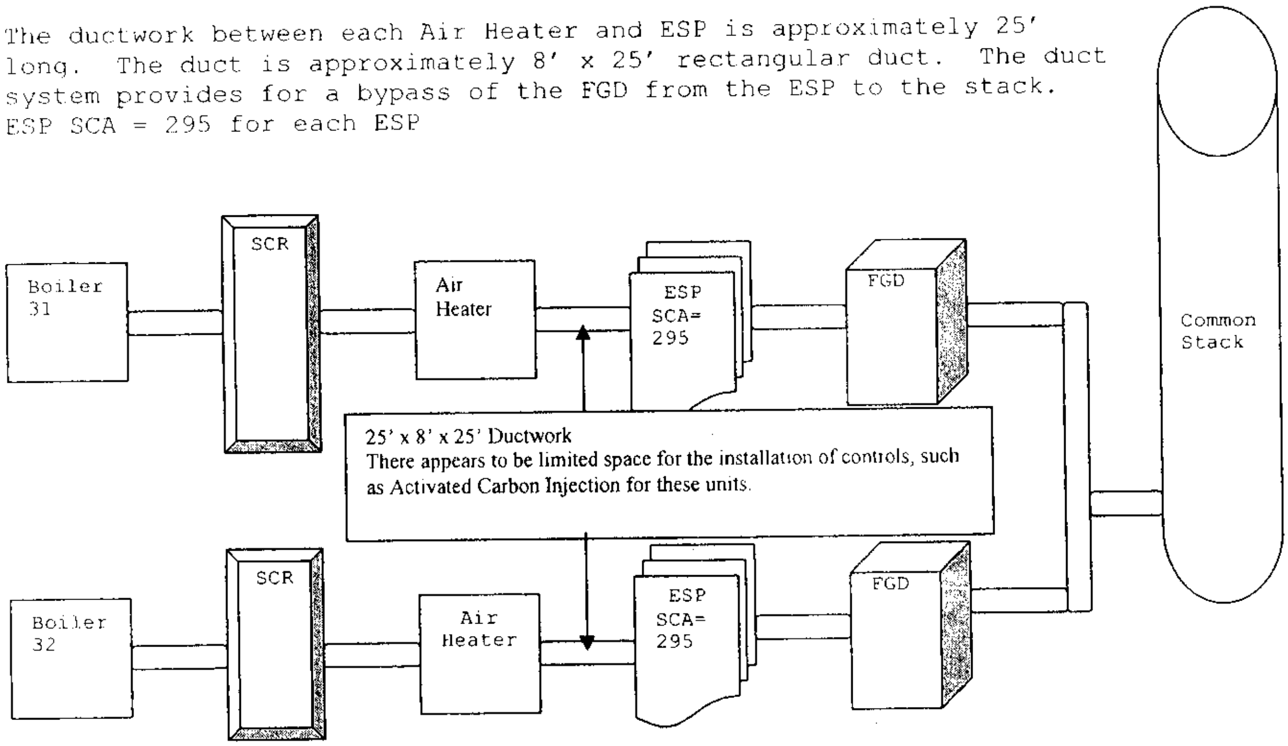
Unit 33

The ductwork between the Air Heater and ESP is approximately 30' long. The duct is approximately 8' x 30' rectangular duct. This duct splits exiting the ESP into two sections that go around the stack and enter the FGD. From the FGD the duct connects back to the stack. There is also an FDG bypass to stack. ESP SCA = 288



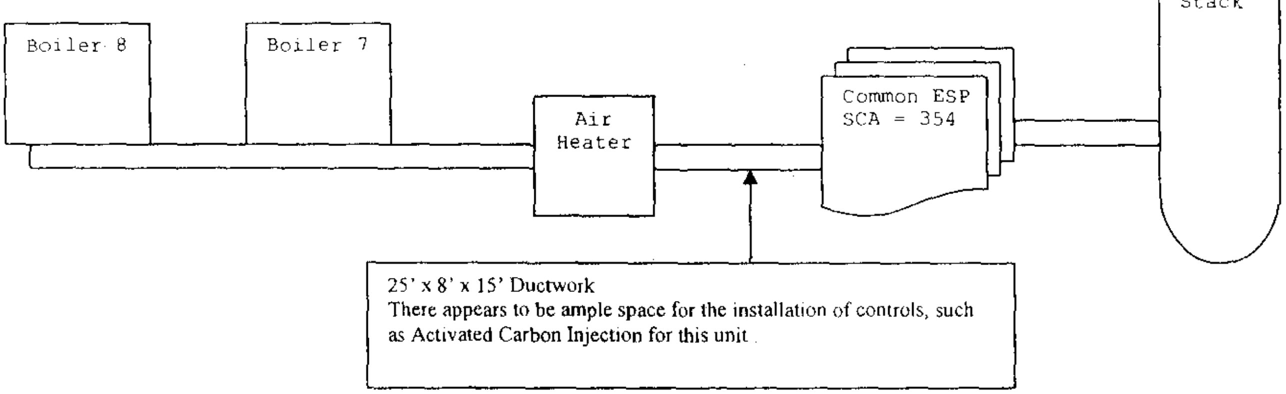
Unit 31 and Unit 32

The ductwork between each Air Heater and ESP is approximately 25' long. The duct is approximately 8' x 25' rectangular duct. The duct system provides for a bypass of the FGD from the ESP to the stack. ESP SCA = 295 for each ESP



Unit 7 and Unit 8

The ductwork begins atop the boiler house 7/8. The duct is approximately 45 ft from boiler 8 to 7 then 25 ft to end of building then 25' on a 45-degree angle down to the ESP. It's approximately 10 feet from ESP to Stack. ESP SCA = 354



2. SO3 injection
The facility does not use SO3 injection. The facility controls the temperature at the economizer section of the boiler on unit 33 in order to decrease the SO2-SO3 conversion. This is accomplished by monitoring the temperature at the economizer in conjunction with curves developed via testing. If the temperature approaches the curve limit the unit is schedule off line for maintenance and the economizer is cleaned. The clean unit allows for lower temperature to reduce the SO2-SO3 conversion. Units 31, 32, 7, & 8 do not achieve temperatures that result in the SO2-SO3 conversion.

3. Flue gas conditioning
No flue gas conditioning is utilized. As a note unit 7 utilizes overfire air for additional NOx control. The SCR's are ammonia gas injection. The facility utilizes Illinois coal.

4. Other Information
City Water, Light, & Power (CWLP) located in Springfield is an electric utility. CWLP utilizes five coal-fired boilers in conjunction with steam turbine generators to generate electricity. Electricity generated by CWLP is primarily generated for the City of Springfield and a few surrounding communities and secondarily sold to other utilities. Coal combusted at this facility is high sulfur Illinois Bituminous received from Viper coalmine in Elkhart.

The facility is divided into two sections known as the Lakeside and Dallman stations. In general, the Lakeside Station consists of coal receiving/storage, coal processing/crushing system, and two coal-fired boilers (LS7 and LS8) each controlled by one electrostatic precipitator (EPLS) then vented to a common stack. Also located at the Lakeside station is a dry-fly ash handling system. This system is controlled by a baghouse designated as LS-BH. The system has not been operated for several years.

The Dallman station consists of coal receiving/storage, coal processing/crushing system, and three coal-fired boilers (units 31, 32, and 33). Units 31 and 32 are each controlled by a separate ESP (EP 31 and EP 32, respectively) then by a common flue gas desulfurization (FGD) system venting to a common stack. Exhaust from Unit 33 is first vented to an ESP (EP 33) then to a FGD system. From the FGD system the exhaust is directed to the Unit 33 stack. Additionally, the facility has installed selective catalytic reduction systems (SCR) to each of the three Dallman Units.

The FGD systems are used to remove sulfur dioxide from the boiler exhaust. Limestone received at the Dallman station is crushed using ball mills. From the ball mills the crushed limestone is mixed with water creating slurry. The slurry is misted through the boilers exhaust via spray towers. Pumps at the bottom of the spray towers move the spent slurry to a settling tank. Settled material is pumped to a de-watering station. In the de-watering stage a rotating vacuum drum is used to pick up the by-product (gypsum). As the drum rotates an edge is used to scrape the gypsum from the drum. The de-watered gypsum is conveyed to a temporary storage area prior to off-site distribution. The cement and agricultural industries currently use this material.

The dry ash handling system located at the Lakeside Station is not currently utilized. Ash from the slag tank of each unit is dropped to a slag tank hopper that feeds to a grinder. The ground ash is sluiced to separate settling ponds located north of the Spaulding Dam. After the ash has settled the material is distributed off-site for use in the construction industry as backfill or as a component in the manufacturing of roofing materials. Currently fly ash and bottom ash are not separated.

Three diesel generators are located just south of the Lakeside Station. These generators were added to the facility for the purpose of black start capability (back up power for the stations). Initial operation began in June of 2002.

Emissions Unit Information

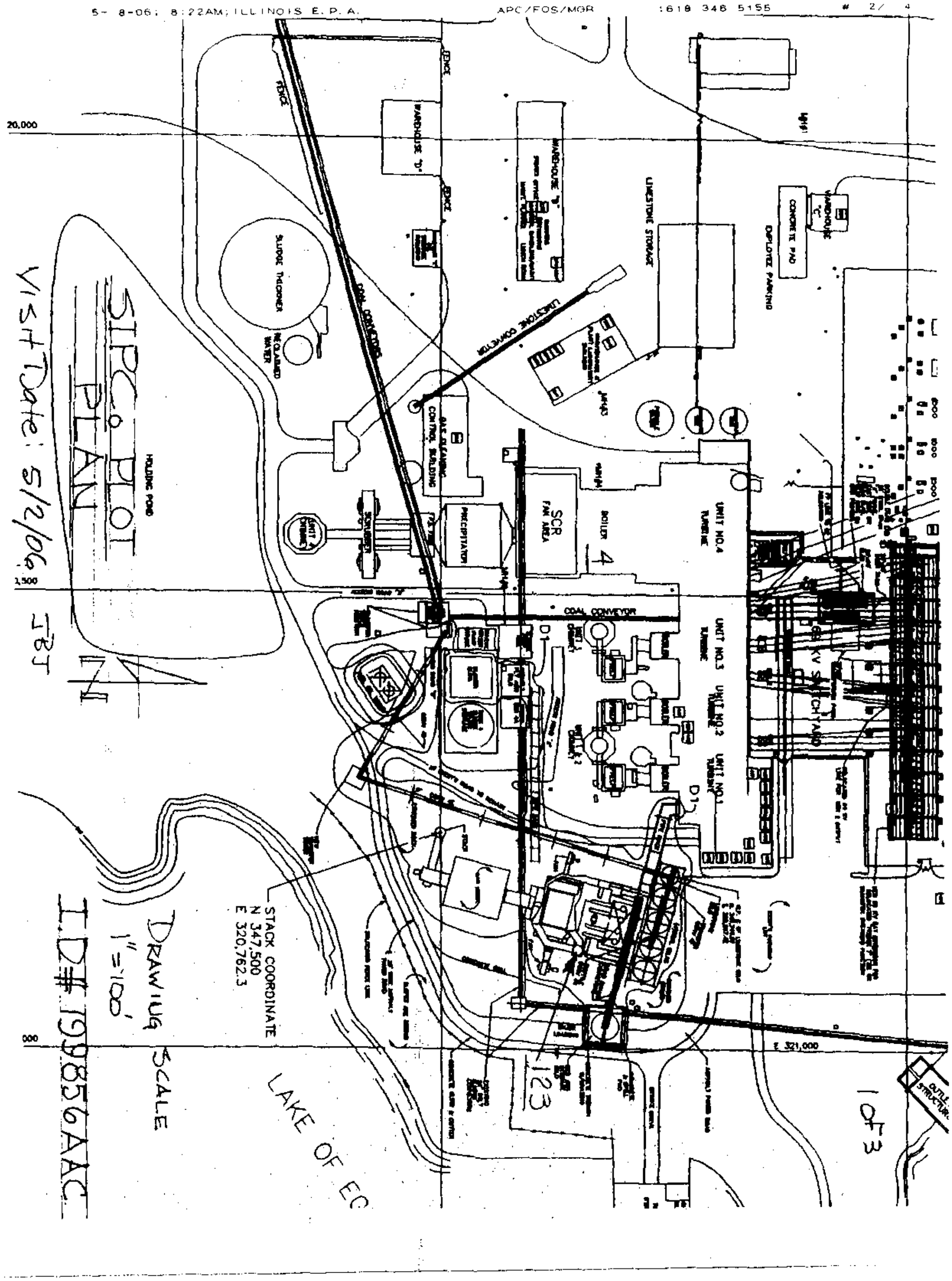
Unit	Manufacturer	Firing Type	Design Heat Input (Output)	Control Equipment	Date of Construction
Unit 7	Babcock & Wilcox	Cyclone	415 mmBtu/hr (33 MW)	EPLS	1959
Unit 8	Babcock & Wilcox	Cyclone	415 mmBtu/hr (33 MW)	EPLS	1964
Unit 31	Babcock & Wilcox	Cyclone	882 mmBtu/hr (88 MW)	EP31/FGD/SCR	1967
Unit 32	Babcock & Wilcox	Cyclone	882 mmBtu/hr (88 MW)	EP32/FGD/SCR	1971
Unit 33	Combustion Engineering	Pulverized	2,120 mmBtu/hr (192 MW)	EP33/FGD/SCR	1975

In addition, the facility supplied drawings of the exhaust systems.

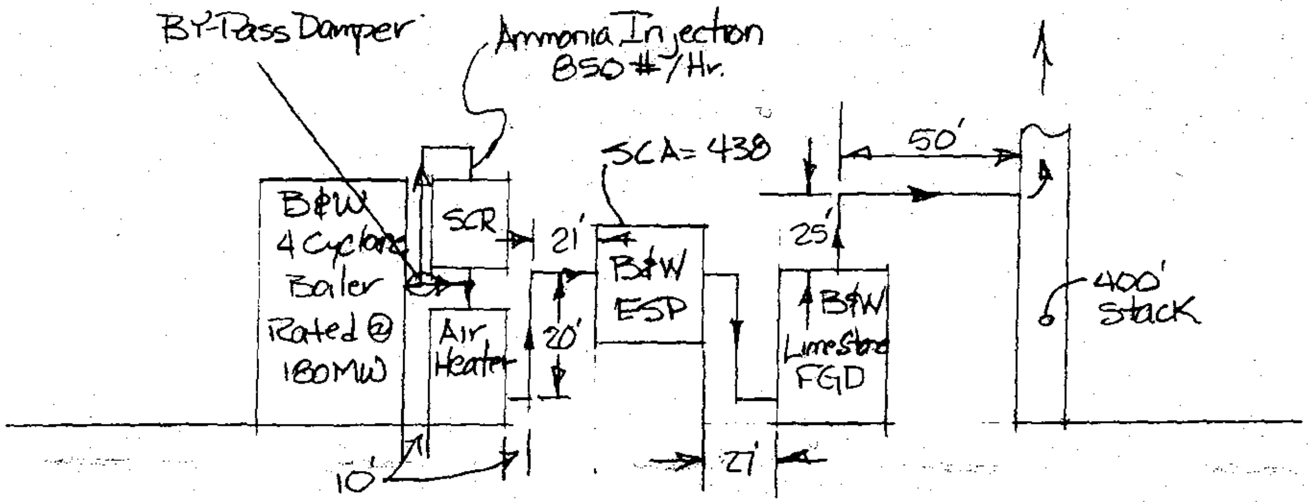
#21 – Southern Illinois Power (Marion)

Unit # 4 .Block diagrams are included in compiled Information and show relative location of boiler # 4 followed by the SCR and/or the air preheater. Flap gate valve accommodates boiler operation with either preheater only or SCR and preheater together. The distance between the SCR and preheaters basically nil since the SCR is immediately atop the preheater. Preheater is followed by two 8'x10'x30' ducts to a common duct that transitions over a distance of 12' into the inlet of the ESP which is ~50'x40'. This makes the ESP a cold- side design. The outlet of the ESP is a 36'x36'duct that transitions a distance of ~27' to two separate ducts immediately prior to entering the limestone FGD wet scrubber. From the top of the wet scrubber gases exit to the stack at the ~ 100' level a distance of ~ 50' to the stack. In agreement with the diagram for and permit covering Unit 4 the SCA for the ESP is 438. As indicated on the diagram there is ammonia injection in the duct just prior to the flue gas entrance to the SCA at the indicated rate of 850 #/hr. I have no knowledge of the space requirements for the installation or technical limitations associated with a well-designed Activated Carbon Injection System. All measurements contained in this report are estimations and not measured values. There is an undetermined amount of SO3 formation in the operation of the SCR as evidenced by a bluish cast to the highly visible plume existing out the Unit 4 stack. Most of this visible plume is condensed water vapor and has never to my knowledge dropped to the surrounding ground level or caused an area complaint.

Unit # 123. The block diagram for Unit # 123 is also attached to the compiled information and was gathered by me on the same date as indicated on the general plot plan for this site. This unit is a circulating fluidized bed boiler as shown with a design generating capacity of 120 mw. This unit fires as indicated a blend of fuels, which typically is made up of Carbon (BTUs per # of 8200 and 2.4 % sulfur) mine run coal (11,250 BTU/#) and a small amount of coke. See diagram for percentages of these. The air heater is internal to the unit in the back portion and was designated as a tubular style air heater. There was no info to define it any more than what it was called. The fuel gas leaves the boiler at the lower back of the unit though a 22' long 10'x8' duct directly into the baghouse which has an air-to-cloth ratio of 3.76 to 1. The baghouse has multiple compartments but based on operating experience cannot isolate any for cleaning purposes and they continue to direct gases though all compartments while cleaning is accomplished. The gases leave the baghouse via a 10' x 8' duct ~ 48' long to the metal stack. Boiler 123 uses a very small amount of ammonia at the inlet to the tubular air heater portion to maintain the NOx emission rate at ~ 0.09 # / mil BTUs.


SIPC PLOT PLAN
Visit Date: 5/2/06
JBJ
Drawing Scale 1"=100'
ID# 199856AAC
STACK COORDINATE
N 347,500
E 320,762.3
LAKE OF EG
1 of 3
UNIT NO.4 TURBINE
BOILER 4
SCR FAN AREA
PRECIPITATOR
COAL CONVEYOR
LIMESTONE STORAGE
LIMESTONE CONVEYOR
SLUDGE THICKENER
HOLDING POND
GAS CLEANING CONTROL BUILDING
UNIT NO.3 TURBINE
UNIT NO.2 TURBINE
UNIT NO.1 TURBINE
KV SWITCHYARD
CONCRETE PAD
D1
123
20,000
E 321,000

Boiler #4

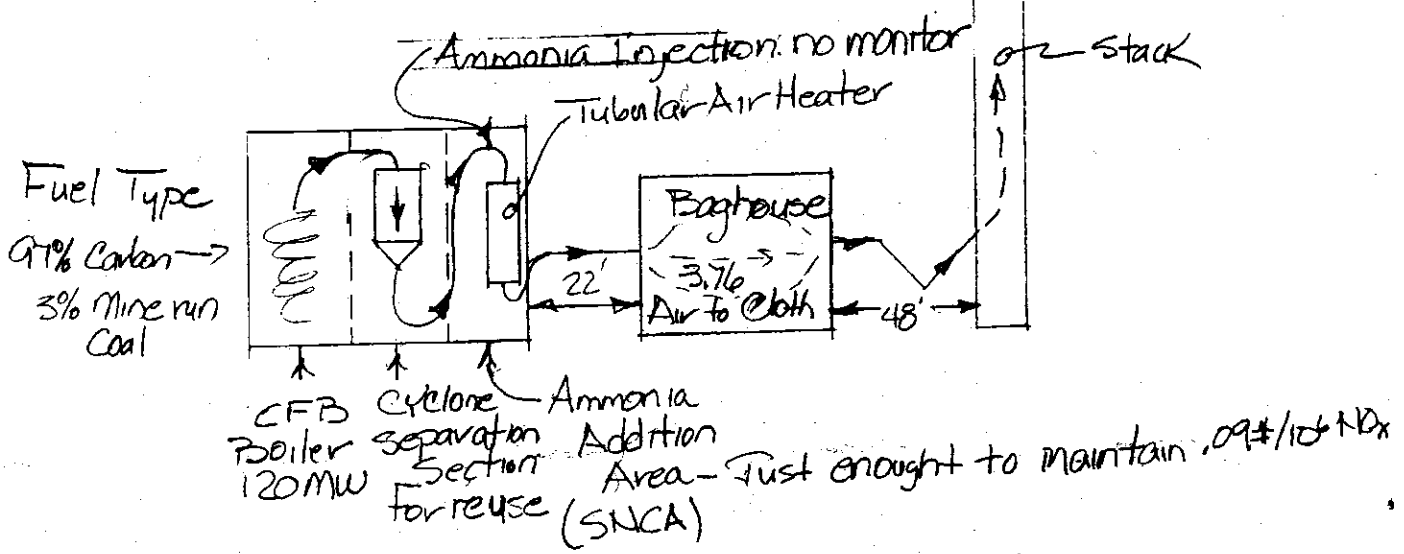


All dimensions are estimates

SIPCo. - I.D.# 199856AAC

Visit Date - 5/2/06
JBJ

Boiler 123 Diagram



SIPCo - I.D. - 199856AAC

Control Configuration Inspections at Illinois Coal-Fired Power Plants - 2006

TABLE OF CONTENTS

2. SO_3 injection

A pilot SO_3 injection project was undertaken in autumn 2004 and abandoned in spring of 2005. Midwest Generation official claimed it had no quantifiable results. Another said it had "mixed results... but they didn't see an impact." The goal of the project was to reduce the resistivity of PRB coal. The pipes and headers were abandoned in place. These are located at the 7^{th} floor at approximately the 116-foot elevation. Gaseous SO_3 was injected at the economizer. The SO_3 generation process was located at ground level.

Fisk also constructed a polymer injection system, which introduced liquid polymer into the ducts after the preheater and upstream of the ESP. The polymer injection system included a header pipe and four spray nozzles installed per duct (16 altogether.) The polymer was supposed to combine with and agglomerate particles in the flue gas to facilitate collection by the ESP. This was done in the time period around 2000. The project was discontinued as the injections accumulated in the ducts producing a series of "stalagmites." The header system and injection ports are still in place.

2. Flue gas conditioning

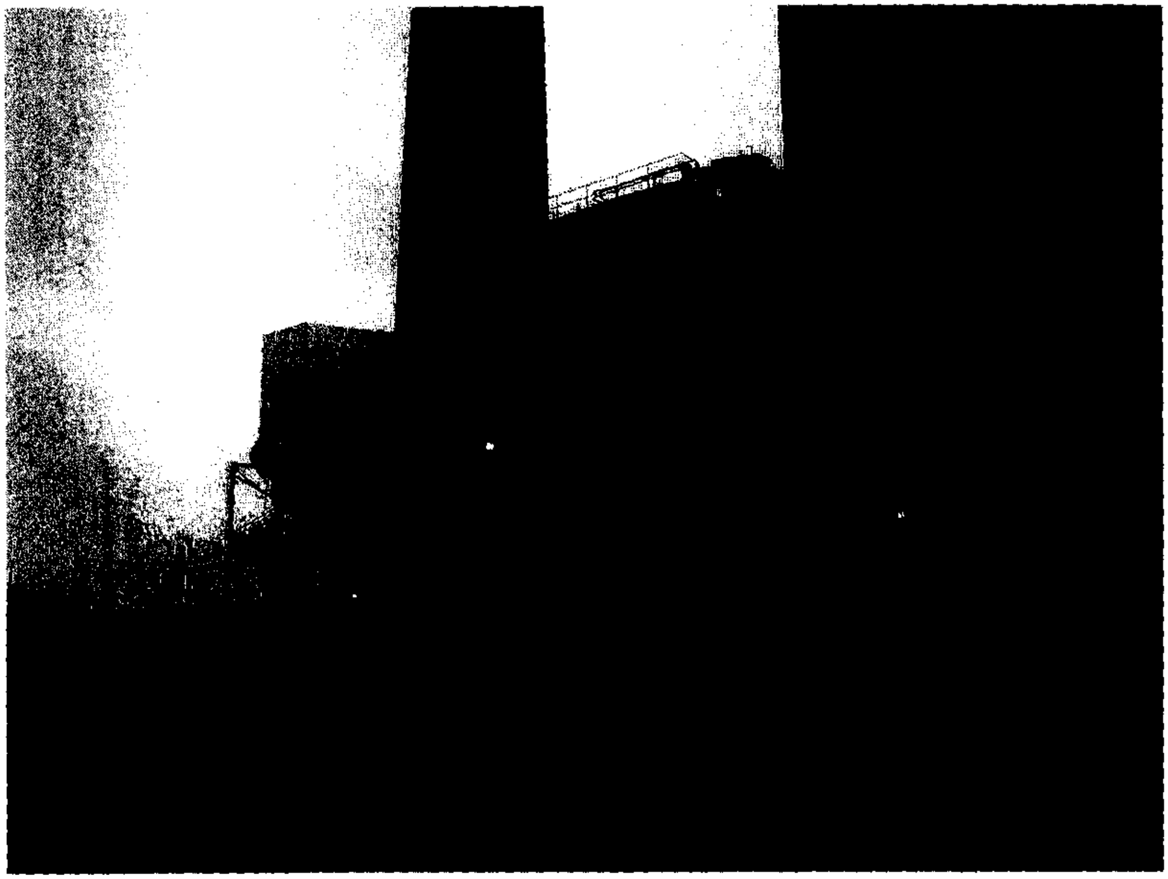
No direct flue gas conditioning is performed. Sodium carbonate, anhydrous is added to the coal at the mine to achieve 3.25-3.75 wt%. The sodium is added to decrease resistivity of the fly ash. Wt % sodium is provided in the quarterly coal analysis reports.

3. Other Information

Fisk Unit 19 is a 3,379 mmBtu/hr electric generating unit consisting of two boilers, a superheater boiler (or "furnace") and a reheat boiler (furnace). This arrangement is known as a "dual furnace." They are basically identical except for the arrangement of tubes in the fireboxes. Each furnace cannot be run separately.

Low sulfur Powder River Basin coal is utilized to achieve sulfur dioxide limits. Unit 19 utilizes low NO_x burners and overfire air for NO_x control.

The ESPs are considered "cold side" since they are located after the preheaters.



This is a view of the west ESP at Fisk with breeching exiting the ESP and entering the stack. (In the background is the bottom of the Sears tower.) The air preheaters are inside the large building to the right. The preheaters are about 4 feet from the wall at about the same elevation as the ESP. The section of dark transition before the silver ESP pictured and the building is about 25 feet long. It probably houses perforated plates which distribute air into the ESP in a laminar type flow. Total distance of ductwork from exit of preheater to ESP is about 29-35 feet.

2. SO_3 injection

The facility does not use SO_3 injection.

3. Flue gas conditioning

No direct flue gas conditioning is performed. Sodium carbonate, anhydrous is added to the coal at the mine to achieve 3.25-3.75 wt%. The sodium is added to decrease resistivity of the fly ash. Wt % sodium is provided in the quarterly coal analysis reports.

4. Other Information

Crawford Unit 7 is a 216 MW electric generating unit consisting of two boilers, a superheater boiler (or "furnace") and a reheat boiler (furnace). This arrangement is known as a "dual furnace." They are basically identical except for the arrangement of tubes in the fire box. Each furnace cannot be run separately. The superheater furnace supplies high pressure steam to the high pressure turbine, the steam is then routed to the reheat furnace. The turbine on the reheat furnace operates at a lower pressure and utilizes a condenser to extract remaining energy from the steam.

Low sulfur Powder River Basin coal is utilized to achieve sulfur dioxide limits. Unit 7 utilizes low NO_x burners and overfire air for NO_x control.

The ESPs are considered "cold side" since they are located after the preheaters.

ESP collection area is given in what is called "specific collection area," the units of which are ft^2/acfm. The design flow rate (acfm) was not given. The specific collection areas (for units 7 and 8) were taken from stack test reports. Originally the SCA was given as 118.3 and it was suggested by Midwest Generation that to get the individual SCA per ESP to divide the number by two.

A further note about the ducts: There did not appear to be any obvious large open areas near the superheater duct. At low elevations, there is a considerable amount of electrical equipment to the west. At slightly higher elevations, a number of prominent vessels for the feedwater system are placed close to the duct. Then the wall of the building runs adjacent to the duct on the west side of it. On the east side, there is not much room between the down coming duct (hot gas to the air preheater) and the outgoing duct. At one elevation, there did appear to be a large "patch" placed into the side, approximately 25 feet by 6 foot tall section may have been welded into place (see photo.) There is also a steel beam truss section which could support a pad at this approximate 77-foot elevation. We did not see any convenient places in which large equipment (baghouses/ storage silos) could be easily placed. The reheat furnace duct had an adjacent approximately 400 sq foot area open to the East and some windows were within 20 feet east.

ADDENDUM

Date: May 16, 2005
To: Ed Bakowski
From: Joe Kotas

RE: Mercury VIP
SCA CORRECTION

Source:	Midwest Generation, LLC; Crawford Generating Station
I.D. #:	031600 AIN
Address:	3501 S. Pulaski Road; Chicago, IL 60623-4987
Contact/Title:	Luke Ford/EH&S Specialist,John Kennedy/Station Director; David Gladem/Production Manager
Phone/Fax:	773-650-5489
Inspector(s):	Joe Kotas and Emilio Salis

Following an inquiry, further information was gathered concerning the specific collection area ("SCA") of the ESPs at Crawford Unit 7. The SCA for Crawford unit 7 was originally given as 59.15 in the report dated 05/06/06. The correct SCA (as provided by contacts at Midwest Generation) for Crawford Unit #7 is 118.3 ft^2/kacfm. Please adjust your records accordingly.

The facility does not use SO_3 injection.

3. Flue gas conditioning

No direct flue gas conditioning is performed. Sodium is added at the mine as stated above (which is true for all Midwest Generation plants in the Chicago area.)

4. Other Information

Crawford Unit 8 is a nominal 326 MW electrical generating unit consisting of a dual furnace arrangement connected to a single stack.

Low sulfur Powder River Basin coal is utilized to achieve sulfur dioxide limits. Unit 8 utilizes low NO_x burners and overfire air for NO_x control.

The ESPs are considered "cold side" since they are located after the preheaters.

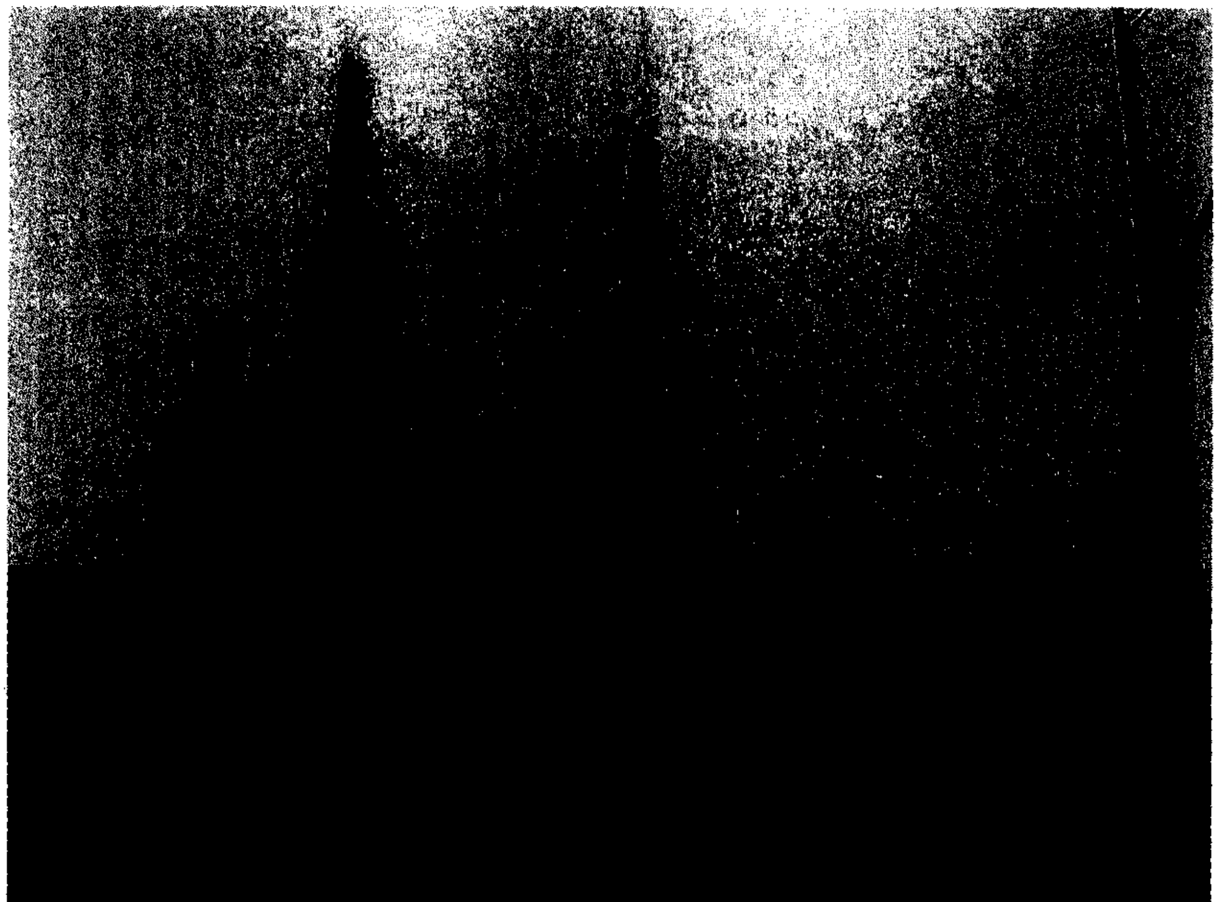
The preheaters are of a "Ljungstrom" design. They consist of cylindrical metal drums with fins. The axis of rotation is between the inlet (cold) and outlet (hot) air streams. The unit rotates to allow the preheated fins to come in contact with the incoming combustion air. The temperature of the flue gas is 600-700 degrees F entering the preheater and 300 degrees F out.

5. Attachments

a. Photos. (Midwest Generation Crawford Generating Station photos)

b. Side view schematic Crawford 7. (Crawford block)

Midwest Generation Crawford Generating Station
031 600 AIN
05/01/06
Photos by J. Kolas



View of Crawford power plant looking south. Unit 7 has two electrostatic precipitators (ESPs) on the roof and an orange and white striped stack. The unit 8 stack is in the foreground.

2. SO3 injection

The facility does not use SO3 injection in any of the boilers.

3. Flue gas conditioning

No flue gas conditioning is utilized.

4. Other Information

This facility is an electric-powered generating station with two units, 5 and 6, each consisting of two crushed coal-fired boilers controlled by ESP units and a turbine-driven generator. Unit 5 covers boilers number 51 and 52 and Unit 6 covers boilers number 61 and 62. The ductworks for all these boilers are identical. Each boiler has a nominal capacity of 4116 mmBtu/hr each and are served by a single shared stack. NOx emissions are controlled by low-NOx overfire air systems and the PM emissions are controlled by ESP. Generators for units 5 and 6 are permitted for 851 MW and 846 MW, respectively.

Coal is received by rail into a car dumper and coal crushers and then moved by conveyor to the stockpile or surge bins. From the surge bins, coal is fed by a conveyor to the conditioners and then to the silos. All sources, including the fly ash bins; with uncontrolled emission rates greater than the allowable rate are controlled by bag houses. The coal silo for unit 5 also has a wet dust extractor system and there are dry fogger systems on the traveling tripper car and at some tripper room transfer points. Other sources are an auxiliary oil-fired boiler for facility heating and start-up steam for units 5 and 6, several insignificant storage tanks, a gasoline dispensing station, coal storage pile, and roadways.

Emissions Unit Information

Emission Unit	Description	Emission Control Equipment
Unit 5 Boiler BLR 51	Babcock and Wilcox Dual Cyclone fired Nominal 4116 mmBtu/hr (1973)	Low NOx, Overfire Air and ESP
Unit 5 Boiler BLR 52	Babcock and Wilcox Dual Cyclone fired Nominal 4116 mmBtu/hr (1973)	Low NOx, Overfire Air and ESP
Unit 6 Boiler BLR 61	Babcock and Wilcox Dual Cyclone fired Nominal 4116 mmBtu/hr (1976)	Low NOx, Overfire Air and ESP
Unit 6 Boiler BLR 62	Babcock and Wilcox Dual Cyclone fired Nominal 4116 mmBtu/hr (1976)	Low NOx, Overfire Air and ESP

In addition, the facility supplied flow diagram of the boilers operation.

3. Flue gas conditioning

No other flue gas conditioning is utilized.

4. Other Information

Low sulfur coal is utilized. All boilers incorporate low NOx technology and over-fired air.

2. An SO_3 flue gas conditioning system has been installed on Units 1 and 2. A 3,000 molten sulfur tank supplies sulfur that is used to make SO_2 for both units. The SO_2 is forced into SO_3 and put into the flue gas. With a letter dated August 2, 2001, Steve Whitworth notified the Agency that the flue gas conditioning system for Unit 1 was placed into service on July 16, 2001 and released to operations on July 17, 2001. The flue gas conditioning system for Unit 2 was placed in service on July 10, 2001 and released to operations on July 13, 2001. During the inspection, both units were operating and the SO_3 injection rate for Units 1 and 2 was 9ppm and 10ppm, respectively. The facility burns Powder River Basin coal and East Hornsby Coal. The SO_3 injection system is used for both.

3. No other flue gas conditioning is performed.

4. The coal-fired boilers are designated as Unit 1 (CB-1) and Unit 2 (CB-2). They have a steam production capacity of 2.5 million pounds per hour and 4.159 million pounds per hour, respectively. Both are Babcox and Wilcox subcritical cyclone-fired units. Unit #1 and Unit #2 have overfire air systems for reducing NOx emissions. According to an email from the facility dated May 16, 2002, "full utilization of the overfire air systems on Unit #1 and Unit #2 was not realized until late in 2001 and early 2002". The overfire air systems did not have full capability until the fine grind crushers were installed. The overfire air systems operate all year.

   The facility installed selective catalytic reduction (SCR) systems on both units. The manufacturer will not guarantee the catalyst in the SCR during ozone season while burning low sulfur coal. The SCR mixes ammonia with the exhaust gas. It is located before the precipitator on the hot side. There are two 50,000 gallon anhydrous ammonia tanks for supplying the SCR units. The SCR system operates May through September. It needs to operate at about 800 degrees Fahrenheit for optimum performance. The SCR on Unit #2 initially started up on April 9, 2002. The SCR on Unit #1 was in service May 1, 2003.

2. The facility performs SO_3 injection on Boiler #5. Boiler #5 (unit 3) is a 220 MW coal-fired boiler equipped with a low NOx burner system. It has an electrostatic precipitator and a sulfur dioxide monitor. The boiler is burning Powder River Basin coal which contains low sulfur. A flue gas conditioning system was installed on boiler #5. It was needed for burning the low sulfur coal. The flue gas conditioning system burns molten sulfur making SO_2. The system oxidizes the SO_2 into SO_3. The SO_3 is put into the flue gas which lowers the resistivity of the fly ash making it easier for the precipitator to collect. The system was place in service on March 22, 2003 and was operating reliably April 14, 2003. During the inspection, SO_3 was being injected at a rate of 7.98 ppm. The system has the capability of injecting SO_3 at a rate of 6 to 14 ppm.

3. Flue gas conditioning is also performed on Boiler #4. A non-sulfur liquid conditioning agent called Arkay is used. The facility was issued a construction permit (#06010047) on February 16, 2006 to do a "pilot evaluation of an alternative flue gas conditioning agent" on Boilers #1-5. The facility has immediate plans to install the Arkay flue gas conditioning systems on Boilers #1-3 after receiving the construction permits. They plan to make the Arkay system on Boiler #4 a permanent system and no longer a "pilot evaluation".

4. The Meredosia power station has a total of six boilers divided into four units. There are two coal-fired boilers (#1 and #2) with a generating capacity of 32 MW each. There are also two coal-fired boilers (#3 and #4) with a generating capacity of 30 MW each. The boilers #1-#4 have a common stack. The units are equipped with SO2, NOx, and opacity monitors. Boiler #5 (unit 3) is a 220 MW coal-fired boiler equipped with a low NOx burner system. It has an electrostatic precipitator. Boiler #5 has a separate stack.

This facility is an electric generating station with one boiler, a pulverized coal, wall fired boiler rated at 3,713 million BTU per hour or about 400 MW.

For NOx control there are low NOx burners on the boiler and a SCR system with ammonia injection. Particulates are controlled by two parallel, cold side, ESP's with flue gas conditioning by means of SO_3 injection. Sulfur dioxides are controlled by a limestone wet scrubber system.

The SO_3 injection system was just started up in March 2006. The proper permits were obtained. The coal presently being used can be described as a medium sulfur content coal of up to 2%. This amount is high enough to continue to require the use of the wet scrubber for SO_2 control, but low enough to require flue conditioning with SO3 injection for proper ESP performance. The ESP's were designed for use with high sulfur coal, but with the lower sulfur coal, SO_3 needs to be injected to modify the resistivity of the flyash particles for proper ESP operation.

The current scrubber is reaching the end of its life. The company is currently investigating whether rebuilding the scrubber or replacing the scrubber is most economic. If the scrubber system needs to be shutdown while a new one is built or rebuilt, then low sulfur will be temporarily used to meet the SO_2 emission limits.

The SCR was put into service in about June 2003 and presently operates from May through September, the ozone season. New rules may require year round operation by 2009. The SCR system produces a little SO_3 so the SO_3 injection system is operated at a reduced rate in proportion to the amount from the SCR to maintain about 10 ppm of SO_3 in the flue gas.

The duct between the air heater and the ESP's is about 212 feet long but is not in a straight line. The single duct connection at the pre-heater is 14 x 25 feet (352 sq. ft.) and it splits into two sections, one for each ESP. Each connection to the ESP's is 7 x 33 feet (464 sq. ft.) The specific collection area (both ESP's combined) is 291.

Rizwan Syed and Wayne Kahila, both from the Peoria Regional Office, did this inspection.

cc: W.Kahila
R.Syed
ID: 057 801 AAA

Sulfur dioxide is controlled by burning coal with the proper sulfur content. The average SO_2 emissions from all three boilers are limited to 4.71 lbs. SO_2/million BTU. Any one boiler may have up to 6.6 lbs. SO_2/million BTU as long as the overall average is not exceeded. Also, on a plant wide basis, the 24-hour average for SO_2 emissions shall not exceed 34,613 lbs. SO_2/hour. Reports of coal analyses have been submitted to the Agency in a timely manner. Quarterly reports of the sulfur dioxide monitoring have been submitted in a timely manner.

Unit 1:

The ESP is a cold side one. The duct from the air pre-heater to the ESP is a twin duct. Each section is 7 x 20 feet (274 sq. ft.) at the outlet of the pre-heater and 16 x 34 feet (1088 sq. ft.) at the inlet to the ESP. The total duct length is about 61 feet; however, this is not a straight line distance. There are many curves and angles in this length of duct. The equipment is tightly squeezed together.

The ESP specific collection area is 138.

The only flue gas conditioning is SO_3 injection. Elemental sulfur is burned to make SO_2 and a catalyst converts the SO_2 into SO_3. The injection averages about 10 ppm of SO_3. The SO_3 system is necessary for the ESP to work properly with low sulfur coal since the ESP was designed to operate with high sulfur coal.

Unit 2:

The ESP is a cold side one. The duct from the air pre-heater to the ESP is a twin duct leaving the pre-heater but is combined into a single inlet at the ESP. Each section is 11 x 28 feet (612 sq. ft.) at the outlet of the pre-heater and 27 x 74 feet (1968 sq. ft.) at the inlet to the ESP. The total duct length is about 46 feet; however, this is not a straight line distance. There are many curves and angles in this length of duct. The equipment is tightly squeezed together.

The ESP specific collection area is 170.

The only flue gas conditioning is SO_3 injection. Elemental sulfur is burned to make SO_2 and a catalyst converts the SO_2 into SO_3. The injection averages about 8 ppm of SO_3. The SO_3 system is necessary for the ESP to work properly with low sulfur coal since the ESP was designed to operate with high sulfur coal.

Unit 3:

The ESP is a cold side one. The duct from the air pre-heater to the ESP is a twin duct. Each section is 12 x 29 feet (638 sq. ft.) at the outlet of the pre-heater and 32 x 49 feet (3056 sq. ft.) at the inlet to the ESP. The total duct length is about 31 feet; however, this is not a straight line distance. There are many curves and angles in this length of duct. The equipment is tightly squeezed together.

The ESP specific collection area is 178.

The only flue gas conditioning is SO_3 injection and SCR system. Elemental sulfur is burned to make SO_2 and a catalyst converts the SO_2 into SO_3. The injection averages about 12 ppm of SO_3. The SO_3 system is necessary for the ESP to work properly with low sulfur coal since the ESP was designed to operate with high sulfur coal.

Unit 3 also has a SCR system with ammonia injection. Data from the catalyst manufacturer indicates that the catalyst in the SCR converts about 1% of the entering SO_2 into SO_3. The rate of the SO_3 injection system is adjusted to account for the SO_3 from the SCR system so that the total SO_3 is about 12 ppm. Presently the SCR system operates only during the ozone season, which is May through September. It may go to year round operation in 2009.

Rizwan Syed and Wayne Kahila, both of the Peoria Regional Office, did this inspection.

cc: W.Kahila
R.Syed
ID: 143 805 AAG

Emissions Unit Information

Emission Unit	Description	Emission Control Equipment
Boiler 9	Babcock & Wilcox Radiant Coal-Fired Boiler 447 MW Nominal Rating (1978). (pulverized coal wall fired)	Overfire Air System, Low NOx burners, In-duct Selective Catalytic Reduction System and ESP with Flue Gas Conditioning

2. SO3 injection

The facility does not use SO3 injection in the boiler.

3. Flue gas conditioning

The facility does use flue gas conditioning and is done between the boiler and the agglomerator. The flue gas additive used is manufactured by ADA and is sodium based and ADA proprietary.

4. Other Information

The Havana Power Station is located on the Illinois River approximately one mile south of Havana, Illinois. The facility has six major fossil-fuel-fired generating units, which are essentially divided into two parts.

The original plant was the first generating station built by Illinois Power. Station construction planning began in 1944 with the five units coming on-line between 1947 and 1950. These original units are steam powered by eight # 6 fuel-oil-fired boilers. # 2 fuel oil is used to ignite the # 6 fuel oil. All eight boilers are connected to a common steam header that supplies the five turbine generators, each rated at 48 MW. All eight boilers are connected to a common exhaust header, which in turn is connected to three exhaust stacks.

The second plant houses Havana Unit # 6 (Boiler # 9), which is rated at approximately 490 MW and is fired with low-sulfur pulverized coal and is wall fired. Construction began on this unit in 1975, and the unit came on-line in 1979. Coal is transported to the station either by barge or rail car where it is unloaded, stored, crushed, elevated to the coal silos in the Unit # 6 building, pulverized, and blown into the boiler for combustion. Upgrades to the existing coal handling and processing system, including a new crusher, new fly ash transport and loadout systems, flue gas conditioning system and a temporary portable coal conveying system were made and the new coal crusher and associated conveyors began operation on January 9, 2005 and achieved maximum production rates on February 1, 2005. The temporary portable coal conveying system was removed once the main conveyors began operation. Exhaust gases from the boiler pass through an electrostatic precipitator to remove fly ash and then pass through a selective catalytic reduction (SCR) unit to control NOx emissions. The facility is installing a agglomerator between the boiler and the ESP which is hot side. The agglomerator has a series of charge plates to collect small particles to attract to each other and assist in enhancing the efficiency of the ESP. The agglomerator by itself is not an emission source or a control equipment. According to the Dynegy staff, the Agency's office in Springfield was notified about this installation. From the SCR, the exhaust gas flows through the air heater then up the stack Prior to installation of the SCR over-fire air fans were installed and began operation on March 03, 2003 to provide some NOx control. The SCR system began operation on August 04, 2003. The boiler has started burning low-sulfur sub bituminous coal in place of low-sulfur bituminous coal on January 19, 2005.

Presently, about 12 startups of Unit # 6 occur per year. Dynegy has changed the station's operating status to a base load unit. Prior to the change, about 150 startups per year occurred.

#15 – Dynegy Midwest Generation (Hennepin)

Division of Air Pollution Control – Field Operations Section

ID# 155 010 AAA
Dynegy Midwest Gen.
Field Inspection Report

Special Inspection Memorandum

Date: May 4, 2006 (revised)

Date of Inspection: April 28,2006

To: E. Bakowski

Last Inspection: not relevant

From: J. Krolak & W. Kahila

ID: 155 010 AAA **R/D:** 203

County: Putnam **SIC:** 4911

Source: Dynegy Midwest Generation, Inc.
Address: R.R.1, Box 200A, Hennepin, IL 61327

Contact: Jim Dodson **Title:** Plant Manager
Phone: 815-339-9212 **Fax:**

Contact: John Augspols **Title:** Environmental Coordinator
Phone: 815-339-9218 **Fax:** 815-339-2772

Contact: Michelle Chestnut **Title:** Environmental Specialist (Decatur)
Phone: 217-872-2367 **Fax:** 217-876-7475
Cell: 217-714-4794

Description: This facility is a coal-fired electric generating station that now burns western sub-bituminous low-sulfur coal to meet federal acid-rain prevention requirements. Dynegy Midwest is the successor (for fossil-fuel power generation) to Illinois Power Company.

2. SO_3 Injection

Dynegy's Hennepin Station burns only low-sulfur Powder River Basin (PRB) coal, and uses SO_3 injection after the air heater exhaust to enable the ESPs to function properly. The sulfur use rate and resultant SO_3 concentration are not directly measured; the optimum concentration is dependant on exhaust gas parameters and is determined by observing the ESP power levels and the plume opacity and appearance. Inadequate SO_3 results in excess emissions and opacity, while a slightly bluish plume indicates too much SO_3.

3. Flue gas conditioning

No other flue gas conditioning is utilized beyond the furnace NO_x controls.

4. Other Information

The station is located in an agricultural/ industrial area within the corporate limits of Hennepin in Putnam County, and is an electric utility. The two coal- or natural gas-fired units at this station are capable of generating a total of about 316 megawatts. No other commercial generating units are located here.

Under Board Regulations, the station's combined SO_2 emission limit is 17,050lbs/hr due to the 264foot stack height. Burning PRB coal, actual emissions do not approach this limit.

The station is located on the south bank of the Illinois River, and coal is delivered to the site by barges.

Construction of Unit 1 was begun about 1950, followed by the larger Unit 2 about 1956. Due to the lack of space at the site, the ESPs for both units are located above the respective ID fans, with the common stack between them. Unit 2's ESP is located higher above the ID fans to allow space for the larger ductwork and breeching underneath it.

When considering how to reduce sulfur emissions to meet acid rain restrictions, the owner (formerly Illinois Power Company) determined that it was not economically feasible to install additional flue-gas control systems such as scrubbers, or to increase the size of the ESPs. The only means left was the use of low-sulfur coal and SO_3 injection.

It is apparent that emission control systems requiring enlarged or additional structures could not be fitted between the furnaces and the river. Lateral expansion might be accommodated, probably at a considerable expense.

The Unit 2 ESP was refurbished in 2003, as described in Dynegy's letter of January 29, 2003 to Don Sutton of the Agency. The Collection Plate Area and SCA information on form 260-CAAPP, page 164 of the original CAAPP application submitted in September 1995, is no longer correct. Information received from Dynegy on May 4, 2006 states that the collection plate area is now 109,200sq ft, and the Specific collector Area (SCA) is 125.5.

CC: Dean Hayden
Wayne Kahila

3. SO_3 Injection:
The facility presently utilizes SO_3 injection, however, the system may or may not be utilized in conjunction with new mercury/PM baghouse control.

4. Flu Gas Conditioning:
The plant previously tried flue gas conditioning when using high sulfur coal. The boilers have been switched to Powder River Basin coal (PRB) and this system will no longer be used.

5. General Boiler Description:

3.2 Unit #1 Boiler with ESP and low NOX combination system

Dynegy has two Combustion Engineering tangentially fired pulverized coal boilers (Units #1 and #2). Unit #1 has a maximum rated capacity of 84 MW (785 mmbtu/hr). Each Unit has 4 pulverizers and 16 burners. Each pulverizer feeds 4 burners that are located at each corner of the boiler. The pulverized coal is injected at four levels of the boiler. Each pulverizer corresponds to a different height at which coal is injected into the boiler. The emissions from each unit are exhausted through an electrostatic precipitator and then through a common stack.

Electrostatic precipitators (ESP) control the particulate matter emissions from the boilers. The ESP for Unit #1 is a Buell with 4 sections (4 TRs). The ESPs uses a hammer/anvil type rapper to remove particulate matter from the plates. Particulate matter emissions from Unit 1 are limited to 0.12 lbs/mmbtu per 35 Ill. Adm. Code 212.203(b).

Sulfur dioxide (SO_2) emissions from Units #1 are uncontrolled. SO_2 emissions are limited to 8.5 lb/mmbtu by 35 Ill. Adm. Code 214.184. In addition, SO_2 emissions from both units #1 and #2 are limited to 16,805 lbs/hr by permit special condition. Construction permit PN05030030 was granted 4/6/05 to install new SO_3 gas conditioning system for ESP unit to burn low-sulfur coal (PRB) and reduce PM and SO_2 emissions. SO_3 concentration in the flue gas will be approximately 20 ppm as needed by volume.

Carbon monoxide emissions from the boilers are subject to 35 Ill. Adm. Code 216.121 (200 ppm corrected to 50 percent excess air).

Dynegy has SO_2, NOX, CO_2, flow and opacity continuous emissions monitors (CEM/COM) located in the stack. Dynegy installed these monitors because of the Acid Rain regulations, 40 CFR Part 75. However, Dynegy is required by permit special condition to submit quarterly reports of excess opacity and SO_2.

Unit #1 and its ESP are permitted in CAAPP operating permit 95090050 and state operating permit 73020064.

3.3 Unit #2 Boiler with ESP and low NOX combination system

Dynegy has two Combustion Engineering tangentially fired pulverized coal boilers (Units #1 and #2). Unit #2 has a maximum rated capacity of 113 MW (1,167 mmbtu/hr). Each Unit has 4 pulverizers and 16 burners. Each pulverizer feeds 4 burners that are located at each corner of the boiler. The pulverized coal is injected at four levels of the boiler. Each pulverizer corresponds to a different height at which coal is injected into the boiler. Unit #2 is equipped with low NOx burners, installed in 1993. The burners take a portion of the airflow that is injected into the bottom and injects the air above the highest burner. The emissions from each unit are exhausted through an electrostatic precipitator and then through a common stack.

Electrostatic precipitators (ESP) control the particulate matter emissions from the boilers. The ESP for Unit #2 the ESP is a Western-Precipitation with 10 sections (5 TR=s). The ESPs uses a hammer/anvil type rapper to remove particulate matter from the plates.

Particulate matter emissions from Unit 2 are limited to 0.1 lbs/mmbtu per 35 Ill. Adm. Code 212.202.

Sulfur dioxide (SO_2) emissions from Unit #2 are uncontrolled. SO_2 emissions are limited to 8.5 lb/mmbtu by 35 Ill. Adm. Code 214.184. In addition, SO_2 emissions from both units #1 and #2 are limited to 16,805 lbs/hr by permit special condition. Construction permit PN05030030 was granted 4/6/05 to install new SO_3 gas conditioning systems for ESP unit to burn low-sulfur coal (PRB) and reduce PM and SO_2 emissions. SO_3 concentration in the flue gas will be approximately 20 ppm as needed by volume.

Carbon monoxide emissions from the boilers are subject to 35 Ill. Adm. Code 216.121 (200 ppm corrected to 50 percent excess air).

Dynegy has SO_2, NOX, CO_2, flow and opacity continuous emissions monitors (CEM/COM) located in the stack. Dynegy installed these monitors because of the Acid Rain regulations, 40 CFR Part 75. However, Dynegy is required by permit special condition to submit quarterly reports of excess opacity and SO_2.

Unit #2 and its ESP are permitted in CAAPP operating permit 95090050 and state operating permit 73020063/construction permit PN05030030.

6. The information concerning ductwork dimensions was received from Dynegy personnel (Rick Dieriex) and is not listed or documented in any permit application or official Dynegy drawing. The actual layout of the new construction of mercury baghouse, associated ductwork, and auxiliary equipment may not be as presented by FOS in this document. The drawings are not to scale.

#18 – Kincaid Generation (Kincaid)

TIER I INSPECTION MEMORANDUM

Date May 2, 2006 Date of Inspection: May 1, 2006

To: E. Bakowski

From: E. Kierbach I.D. #: 021814AAB R/D 204

Source: Kincaid Generation, L.L.C.

Address: PO Box 260: 4 miles west of Kincaid Rt. 104 Kincaid, Il 62540

Contact/Title: Anu Singh, PE/Sr. Environmental Compliance Engineer

Phone: 217-237-4311 x 2291 / 217-237-5519

Inspector(s): Steve Youngblut/Ernie Kierbach

Purpose: Coal fired power plant equipment verification/clarification

1. Block Diagram

The block diagram depicts boilers unit 1 and 2 along with ductwork and controls.

Unit 1 boiler is equipped with over fire air for NOx reduction. The unit exhausts to an ammonia injection selective catalytic reduction system (SCR). From the SCR exhaust travels thru an air heater to an electrostatic precipitator (ESP). The ESP has two main compartments each with a specific collection area (SCA) of 327.5. From the ESP the exhaust travels to a common stack.

Unit 2 boiler is equipped with over fire air for NOx reduction. The unit exhausts to an ammonia injection selective catalytic reduction system (SCR). From the SCR exhaust travels thru an air heater to an electrostatic precipitator (ESP). The ESP has two main compartments each with a specific collection area (SCA) of 327.5. From the ESP the exhaust travels to a common stack.

In either configuration the estimated distance from the air heater discharge to the ESP is 325 feet. There would appear to be ample room for add on control in this section of ductwork.

2. SO3 injection

The facility does not use SO3 injection. A SO3 injection has never been used at the facility.

3. Flue gas conditioning

No flue gas conditioning is utilized.

4. Other Information

Kincaid Generation utilizes two coal-fired boilers in conjunction with steam turbine generators to generate electricity. Electricity generated by Kincaid Generation is sold on the "grid". Coal combusted at this facility is low sulfur Powder River Basin coal (Black Thunder, North Antelope, and Antelope).

The facility, in general, consists of coal receiving/storage, coal processing/crushing systems, a water treatment plant, an auxiliary boiler, and two coal-fired units each controlled by an SCR and electrostatic precipitator (ESP) vented to a common stack.

Each boiler is also equipped with an over fire air system (OFA) to reduce emissions of NO_x to aid in complying with the Acid Rain Program requirements of 40 CFR 76. In general, this is accomplished by reducing airflow (oxygen) in the furnace region resulting in a reduction of NO_x formation.

Additionally, the facility has installed a selective catalytic reduction (SCR) system to each unit. The SCR taps in at the economizer exit and vents to the air heater. The air heater section then vents to the ESP. The SCR systems provide NO_x reductions during the ozone season. The SCR systems will utilize ammonia as a reducing agent to convert nitrogen oxide emissions from the combustion process to nitrogen and water.

Steam from each boiler is fed to a turbine set. A turbine set consists of one high-pressure turbine, one intermediate-pressure turbine, and two low-pressure turbines. The turbine sets are connected to generators that complete the conversion of chemical energy to electric power.

Emissions Unit Information

Unit	Manufacturer	Firing Type	Design Heat Input	Control Equipment	Date Constructed
Unit 1	Babcock & Wilcox	Cyclone	6,634 mmbtu/hr	OFA, SCR, ESP	1967
Unit 2	Babcock & Wilcox	Cyclone	6,406 mmbtu/hr	OFA, SCR, ESP	1968
Aux Unit	Babcock & Wilcox	-	165 mmbtu/hr	-	1984

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
Division of Air Pollution Control--Field Operations Section

TIER II MEMORANDUM

Date: February 27, 2006
To: Ed Bakowski, FOS Manager
From: Scott Arnold, FOS

Date of Inspection: February 9, 2006
Last Insp. Date: February 15, 2005
I.D.#: 127 855 AAC **R/D:** 304
County: Massac **SIC:** 4911

Source: Electric Energy, Inc.
Address: Joppa Steam Station, 2100 Portland Rd., Joppa, IL 62953
Contact/Title: Bruce Parker, Environment Engineer
Phone: 618/543-7531, Ext.: 458
Fax: 618/543-7420

Purpose:

FY06 Workplan Inspection. Also witnessed RATA.

Description:

Electric Energy's - Joppa Generating Station, located near Joppa, Illinois consists of six coal-fired generating units, which supply electricity for the U.S. DOE - Paducah, Kentucky uranium enrichment facility, as well as supply the grid. The facility is a CAAPP source.

Units 1-6 are all Combustion Engineering pulverized coal-fired units rated at 181 MW (1653 mmbtu/hr) capacity. The units started operation between 1953 and 1955. The units are each equipped with Research - Cottrell 5 section (3 TR's) ESP's installed in 1971 and 1972. The ESP's were upgraded in 1993-94 to handle particulate emission from western coal. The units are vented through three 525' stacks, two units per stack. Continuous emission monitoring equipment was installed at the station, as per 1990 Clean Air Act amendment.

The station receives western coal by rail from the Powder River Basin in Wyoming with less than 1% sulfur. The facility burns approximately 4.6×10^6 tons of coal per year.

Following is a summary of station design data

Unit	MW	MMBTU/hr	Type	Age	Equipment	Age	Height
1	181	1653	C-E, P-C	1953	R-C, ESP	1971	525
2	181	1653	C-E, P-C	1953	R-C, ESP	1972	
3	181	1653	C-E, P-C	1954	R-C, ESP	1972	525
4	181	1653	C-E, P-C	1954	R-C, ESP	1972	
5	181	1653	C-E, P-C	1955	R-C, ESP	1972	525
6	181	1653	C-E, P-C	1955	R-C, ESP	1972	

The station's SO_2 limit is 38,865 lb/hr. based on a 3-hour block average.

Findings

I arrived at Electric Energy, Inc. at roughly 10:25 a.m. on the date of inspection. I met with Bruce Parker, Environmental Engineer, and Mike Mercer, Chemist. We began the inspection with a walk through of the facility. On this day, a gas RATA was being finished up on the SO_x, NO_x and CO_2 monitors on all three stacks. They were presently on stack #3, units #5 and #6. Unit #6 was operating at roughly 180 MW. Unit #5 was in start up running at about 100 MW. After Unit #5 reached 180 MW, stack #3 would undergo its' RATA. The RATAs on stacks #1 and #2 were done yesterday with both operating at 360 MW. All the boilers operate at about 180 MW or high load normally, and there are two units vented to each stack.

The RATA was finished yesterday on stacks #1 and #2, Unit #1 and #2 and Units #3 and #4. The RATA was being done by G.E. Mostardi Platt. The stack testing crew chief was Greg Rock. Mr. Rock told me they were doing Methods 6C, 7E and 3A for SO_x, NO_x and CO_2, respectively. Mr. Rock said they were using a dilution extraction system for testing, since Electric Energy, Inc. has the same type CEM system. They were sampling 3 pts., 7 minutes/pt. For 21 minute RATA runs. They were using a Teflon probe. They were doing a minimum of 9 runs on each stack at high load, which is also normal operating conditions.

We next checked out the coal handling system. I observed the dumping of a train. I noted little, if any, opacity. Ron Thompson, the coal-handling supervisor stated that the coal being dumped on this day was going to storage. The #25 stacker was the only one operating. Stackers #23 and #24 were down at this time. I noted opacity in the 5% range from the #25 stacker. I noted no other VE from the storage area or coal piles.

We proceeded to the control room. All units were operating at full load or about 180 MW each, except the #5 unit which was operating at 100 MW and in start up mode. I asked for an received a copy of the CEM data for each stack (attached).

We returned to the office and Mr. Parker provided me with a copy of the "used oil disposal log" (copy) and the "used oil" analysis (copy in general file).

I next asked for coal burned in 2005 (attached). I also asked if any chemical waste had been burned in 2005. Mr. Parker stated there had. There is a chemical waste quantity and analysis in the company's general file. They burned roughly 15,000 gallons of chemical cleaning waste in 2005.

Finally, I asked for and received a copy of 2004 and 2005 emissions (attached).

This completed this inspection. Recommendations will be made.

SAA:jkb/233a/02-28-06

cc: BOA/Marion
Electric Energy, Inc.

Conclusions & Recommendations

The company appears to be in compliance with Agency regulations. Also, I photographed all three stacks. There is no equipment after the ESP and before the stack. All three ESPs are cold side ESP's.

SAA:jkb/233a/02-28-06

cc: BOA-Marion

is a dry-fly ash handling system. This system is controlled by a baghouse designated as LS BH. The system has not been operated for several years.

The Dallman station consists of coal receiving/storage, coal processing/crushing system, and three coal-fired boilers (units 31, 32, and 33). Units 31 and 32 are each controlled by a separate ESP (EP 31 and EP 32, respectively) then by a common flue gas desulfurization (FGD) system venting to a common stack. Exhaust from Unit 33 is first vented to an ESP (EP 33) then to a FGD system. From the FGD system the exhaust is directed to the Unit 33 stack. Additionally, the facility has installed selective catalytic reduction systems (SCR) to each of the three Dallman Units.

The FGD systems are used to remove sulfur dioxide from the boiler exhaust. Limestone received at the Dallman station is crushed using ball mills. From the ball mills the crushed limestone is mixed with water creating slurry. The slurry is misted through the boilers exhaust via spray towers. Pumps at the bottom of the spray towers move the spent slurry to a settling tank. Settled material is pumped to a de-watering station. In the de-watering stage a rotating vacuum drum is used to pick up the by product (gypsum). As the drum rotates an edge is used to scrape the gypsum from the drum. The de-watered gypsum is conveyed to a temporary storage area prior to off-site distribution. The cement and agricultural industries currently use this material.

The dry ash handling system located at the Lakeside Station is not currently utilized. Ash from the slag tank of each unit is dropped to a slag tank hopper that feeds to a grinder. The ground ash is sluiced to separate settling ponds located north of the Spaulding Dam. After the ash has settled the material is distributed off-site for use in the construction industry as backfill or as a component in the manufacturing of roofing materials. Currently fly ash and bottom ash are not separated.

Three diesel generators are located just south of the Lakeside Station. These generators were added to the facility for the purpose of black start capability (back up power for the stations). Initial operation began in June of 2002.

Emissions Unit Information

Unit	Manufacturer	Firing Type	Design Heat Input (Output)	Control Equipment	Date of Construction
Unit 7	Babcock & Wilcox	Cyclone	415 mmBtu/hr (33 MW)	EPLS	1959
Unit 8	Babcock & Wilcox	Cyclone	415 mmBtu/hr (33 MW)	EPLS	1964
Unit 31	Babcock & Wilcox	Cyclone	882 mmBtu/hr (88 MW)	EP31/FGD/SCR	1967
Unit 32	Babcock & Wilcox	Cyclone	882 mmBtu/hr (88 MW)	EP32/FGD/SCR	1971
Unit 33	Combustion Engineering	Pulverized	2,120 mmBtu/hr (192 MW)	EP33/FGD/SCR	1975

In addition, the facility supplied drawings of the exhaust systems.

K 4-22-04
faxed
mailed

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

1021 NORTH GRAND AVENUE EAST, P.O. BOX 19276, SPRINGFIELD, ILLINOIS 62794-9276, 217-782-3397
JAMES R. THOMPSON CENTER, 100 WEST RANDOLPH, SUITE 11-300, CHICAGO, IL 60601, 312-814-6026

ROD R. BLAGOJEVICH, GOVERNOR RENEE CIPRIANO, DIRECTOR

UPS'd
4-23-04

(217) 782-3397
(217) 782-9143 TDD

April 22, 2004

EPA Docket Center (Air Docket)
U. S. Environmental Protection Agency West
Mail Code 6102T
Room B-108
1200 Pennsylvania Ave, NW
Washington, DC 20460

Attn: Docket ID No. OAR-2002-0056

Re: Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units, Proposed Rule; Proposed Rule (69 *Federal Register* 4652, January 30, 2004) ("Proposal") and Supplemental Notice for the Proposal (69 *Federal Register* 2397, March 16, 2004)

Ladies and Gentlemen:

The Illinois Environmental Protection Agency (Illinois EPA) appreciates this opportunity to comment on the U.S. Environmental Protection Agency's (U.S. EPA's) "Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units; Proposed Rule" referred to herein as the "Mercury Proposal" and the Supplemental Notice to the Mercury Proposal, referred to as "Supplemental Notice." These comments supplement the testimony that I presented on behalf of the Illinois EPA at the public hearing held in Chicago on February 26, 2004.

We have stated publicly that Illinois is very committed to substantially reducing mercury in the environment, and the State is aggressively encouraging clean-coal technology that will allow Illinois' abundant coal reserves to be used in the most environmentally responsible manner. The proposals as set forth in the January 30, 2004 and March 16, 2004, *Federal Registers* will impede these efforts.

In brief, our comments on the Mercury Proposal will focus on the following: 1) Mercury is a highly toxic pollutant that needs to be regulated; 2) Mercury must be regulated under the Clean Air Act (CAA) section 112(d), Maximum Available Control Technology (MACT) standard; 3) Under section 112(d), the mercury limits must be more stringent than set forth in the proposals; 4) The final rule must be fuel neutral, without favoring coal from any particular region of the country; 5) Emissions trading of mercury allowances is not appropriate unless each affected unit involved in a trade can demonstrate that mercury hot spots are prevented; and 6) Mercury emissions can and should occur by 2010, and section 112 of the Clean Air Act has sufficient provisions to accommodate this timeframe. Attached please find Illinois EPA's specific comments on the proposal.

Coal-fired power plants are a major source of air pollutants, but their pollution can be significantly reduced using cost-effective technology that is available now, and which will be improved even further in the next few years. Further reductions will reap tremendous benefits in terms of environmental protection. It is imperative that U.S. EPA promulgate rules that will set the tone and direction for the power plant emission reductions that are long overdue and put the Nation on a path to better protect the health of our citizens and its future generations. To shirk its responsibility in this matter would have devastating consequences that will not be able to be fully compensated through State action alone.

If you have any questions regarding our comments, please contact Laurel L. Kroack, Manager of the Division of Air Pollution Control at (217) 524-7636.

Sincerely,

Renee Cipriano

Renee Cipriano
Director

Attachment

cc: Bharat Mathur
Acting Regional Administrator
U.S. EPA Region V

Comments of the Illinois EPA on the Mercury Proposal

Environmental Concerns

Mercury is a highly toxic, persistent, bioaccumulative pollutant that can cause long lasting health problems. It is especially harmful to unborn babies, where exposure can result in a number of neurological deficiencies, including delayed developmental milestones, reduced test scores and cerebral palsy. A National Research Council study commissioned by Congress and published in 2000 estimated that each year about 60,000 children born in the United States could have neurological problems because they were exposed to mercury before birth.

The high levels of mercury found in fish that populate the waters of our State are also of great concern to us. Mercury contamination is widespread throughout Illinois, causing fish consumption advisories to be issued for every waterbody in the State. Illinois is counting on a strong federal mercury reduction program to help us achieve the goal of reducing the amount of mercury deposited into waterbodies in the State. U.S. EPA's proposed rule is unlikely to realize either sufficient reductions or reductions in a timely enough manner to protect our citizens.

The Clean Water Act requires States to identify impaired waters, to determine what reductions in loading need to occur to restore water quality (i.e., develop a Total Maximum Daily Load or TMDL) and to develop and implement plans to accomplish that restoration. When fish from a waterbody are so contaminated with mercury that we must advise our citizens to limit their consumption of fish or face an increased risk of adverse health consequences, that waterbody must be listed as impaired. Under the Clean Water Act, States are expected to have clean-up plans (TMDLs) in place and working by 2015 to address impaired waterbodies. To achieve this goal, substantial reductions in ambient mercury levels and mercury deposition must be initiated in 2010. We believe it is only prudent, sensible public policy that this proposal should also address our obligations under the Clean Water Act.

Moreover, a strong mercury control program would provide significant co-benefits for sulfur dioxide and nitrogen oxide reductions, both of which are important in attaining the fine particulate matter and 8-hour ozone National Ambient Air Quality Standards (NAAQS). We encourage U.S. EPA to require substantial mercury control by 2010, when most ozone and fine particulate nonattainment areas are required to reach attainment under the Clean Air Act.

Coal-fired electrical generating units (EGUs) represent the largest domestic source of mercury emissions, as well as the largest source of emissions of nitrogen oxides and sulfur dioxide. In order to mitigate the significant health impacts of mercury, sulfur dioxide, and nitrogen oxides, and meet our obligations under the federal Clean Air Act and Clean Water Act, we urge U.S. EPA to adopt a more stringent rule that reduces mercury emissions from coal-fired EGUs to the greatest possible extent and within the timeframes states are required to address program compliance under these federal statutes.

Rulemaking Approach

Although U.S. EPA attempts to justify how it can properly regulate mercury emissions from EGUs under either sections 111(d) or 112(n) of the Clean Air Act, Illinois EPA believes that those units must be regulated under section 112(d).

U.S. EPA chooses to interpret part of the language in section 112(n), requiring U.S. EPA to evaluate "alternative control strategies," to justify an approach to regulation of hazardous air pollutants (HAPs) from EGUs other than a listing under section 112(c), standard setting under section 112(d), and compliance deadlines established under section 112(g). U.S. EPA does not provide legislative history or case law that would support such an approach or interpretation.

Nothing in section 112(n) indicates any intent of Congress to allow U.S. EPA to regulate emissions of hazardous air pollutants (as opposed to other air contaminants) from EGUs under any other section than 112, nor does the language in section 112(n) evince any intent of Congress to allow U.S.EPA to exempt EGUs from the multiple requirements of other subsections of section 112. Indeed, if Congress had intended to give U.S. EPA that authority, it could have done so when it drafted section 112(n).

Moreover, regulation under section 111(d) would be inconsistent with the structure of the Clean Air Act itself, i.e., section 112 for the regulation of hazardous air pollutants, sections 108 to 110 for the regulation of sources as necessary to attain a NAAQS, and section 111 to set standards of performance for <u>new</u> stationary sources.

Also, regulation of emissions of hazardous air pollutants from EGUs under section 111(d) would be inconsistent with U.S. EPA's previous findings. Pursuant to section 112(n) of the CAA, U.S. EPA was required to study the hazards to public health that result from the emissions of EGUs and to provide a report to Congress. If the section 112(n) study and report to Congress found that regulation of these sources were necessary and appropriate, U.S. EPA is then required to regulate under section 112. This proposal essentially proposes to rescind the findings U.S. EPA reported to Congress, which concluded that controlling emissions of hazardous air pollutants from EGUs are necessary under section 112. Instead, U.S. EPA now proposes to change to a section 111 finding that it is only "appropriate" to control emissions from these sources. After negating its own conclusion, U.S. EPA then, without resubmitting the report to Congress, has proposed rules pursuant to the authority of section 111, and in the form of a trading program. To regulate EGUs under a section other than section 112, U.S. EPA would be required to delist EGUs under section 112(c). U.S. EPA has not undertaken this process, and cannot, in light of their own report to Congress, do so by claiming they erred in listing under section 112(c) initially.

Finally, U.S. EPA's conclusions that it erred in listing EGUs under section 112(c) cannot be supported by its actions in regards to the proposed maximum achievable control technology (MACT) standards for industrial boilers "National Emission Standards for Hazardous Air Pollutants for Industrial Commercial/Institutional Boilers and Process Heaters" (40 CFR part 63, subpart DDDD) ("Industrial Boiler MACT"). In the Industrial Boiler MACT, U.S. EPA proposes to regulate mercury, nickel and other HAPS from these sources, based on a finding that exposure to these HAPS have adverse health impacts, even though they emit these HAPS in smaller quantities than EGUs.

We do not believe that the rule proposed by U.S. EPA for the control of mercury emissions from EGUs under section 111(d) or 112(n) complies with the requirements of the Clean Air Act.

Although U.S. EPA constructs an elaborate interpretation that allows it to promulgate a trading program under sections 111(d) and 112(n), neither section provides specific authority for promulgating a trading program. Sections 111(b)(1)(B) and (d) and section 112(d) require U.S. EPA to promulgate either a "performance standard" or an "emissions standard." A performance standard as defined by section 111(a)(1) of the CAA means an emissions standard that reflects the "best system of reduction." And, an "emissions standard" under section 112(d)(2) is required to reflect "the maximum degree of reduction that is achievable" (MACT). A trading program does not, by its very structure, require a source to achieve any particular level of emissions reduction. U.S. EPA asserts that a cap and trade program is the best system of reduction because it provides incentives to sources to make early reductions and to go beyond compliance. However, the safety valve and banking features without flow control of the proposed trading program negate the very incentives of a market-based program. For these and other reasons discussed more thoroughly below, we believe that the appropriate and legally required approach for regulating mercury is under section 112(d) of the CAA that requires USEPA to set an emissions standard that each unit would be required to comply with based on MACT, and each EGU would then be required to meet that standard.

We are also very concerned that other important section 112 requirements will be avoided under a section 111(d) approach. As noted in a publication of the Washington, D.C. law firm of VanNess Feldman entitled "EPA's December 15, 2003 Proposed Rule to Regulate Mercury Emissions from Electric Utilities: Summary and Analysis":

> Also of importance is that the alternative cap-and-trade option (under either sections 112 or 111) would include the removal of the electric utility steam generating units from the section 112(c) list. Such an action would shield the affected utility boilers from the more prescriptive MACT standard-setting process related to MACT floors, regulation of all HAPs, the form of standards, and unit specific compliance obligations. In addition, such an action would spare electric utilities from further regulation under section 112, specifically additional tightening of the MACT standards under section 112(d)(6) or residual risk standards under section 112(f), eight years after promulgation of the initial MACT standard.

We are concerned that the timeline in the Proposal is too long, and controls must be required much more quickly. U.S. EPA gives insufficient support for its extended compliance deadline of 2018, which it has acknowledged, based on the elements of the trading program, could extend to 2025 or 2030. Based on the Florida Everglades experience in which stringent controls were applied to incineration sources in the 1990's, resulting in a steep decline in fish tissue levels of mercury within less than a decade, we can conclude that the quicker we start a reduction program, the quicker the risk to our citizens can be reduced. A 2018 compliance date under the section 111(d) proposal would be far too late for Illinois to use the federal mercury rule as part of a plan to restore an impaired waterbody under the Clean Water Act. And, we would be looking at 2028 before substantial fish tissue reductions could occur in the best of cases. That's 25 years before a current public health risk even begins to resolve, and that's too long.

Under section 112(g), the compliance deadline would be three years after the rule adoption, likely in 2007. There is evidence that requiring strict levels of reduction by 2007 would be very difficult, if not impossible, for all EGUs to meet and still ensure electric reliability. However, we believe that mercury reductions can and should be required under the timeframes allowed for by section 112(g), and the final compliance date should be no later than 2010. Although this date is three years beyond the date specified under section 112(g)(3)(A), sufficient authority under section 112 exists to extend this date. The U.S. EPA Administrator, or a State with an approved program under Title V of the Clean Air Act, may extend the compliance date by one year under section 112(g)(3)(A) if the additional period is necessary for the installation of controls. Under section 112(g)(4), the President may exempt any stationary source from compliance with any standard for a period of not more than two years, which period may be extended, if the technology to implement the standard is not available, and if it is in the national security interest to extend the date.

Also as discussed more thoroughly below, we believe that the limits should be much tighter than those proposed by U.S. EPA and the rule should be fuel neutral, i.e., it should not set different reduction levels based on coal type.

Mercury Emission Limits

We believe that for existing coal-fired EGUs an input-based (or input-based equivalent) limit of two pounds per trillion British Thermal Units (lb/TBTU's) or a reduction of 80% should be the MACT standard. This limit should be adopted and required within a timeframe that is legally allowed for under section 112 of the CAA. Various studies, including a U.S. EPA report "Control of Mercury Emissions from Coal-Fired Electric Utility Boilers," which was posted on U.S. EPA's website on February 27, 2004, indicate that these levels of control have been achieved and are projected to be achievable for the types of units and types of coal utilized. Indeed, if the MACT had been properly set as an average of the best performing 12% of EGUs, the MACT standard would have been set at 2.0 lbs/TBTU.

In setting the MACT floor, U.S. EPA looked at emission test results from approximately 80 EGUs. However, there were not enough units tested nor enough test runs to completely rely on this data. While it may be appropriate to apply a statistical analysis to generate a confidence level when working with less than an ideal set of data, the statistical analyses used by U.S. EPA cannot be completely determined or replicated by Illinois. From what Illinois EPA staff have been able to determine, the data have been selected to reflect the worst-case scenario, and then some. This approach is fundamentally inconsistent with MACT standard setting under section 112(d) which is technology-forcing--hence the requirement that the MACT floor be based on the best performing 12% of sources.

U.S. EPA has recommended that under section 111(d) new EGUs that burn bituminous coals achieve a 94% removal efficiency for mercury. The recommended efficiencies for sources burning sub-bituminous and lignite coals are 74% and 68%, respectively.

We recommend that new EGUs should be required to reduce mercury emissions by 90% regardless of fuel type. U.S. EPA determined that the average of the best 12% of 411 plants was 94% control and the average of the best 12% of the select 80 test runs was 93%. Notably, Illinois EPA has recently issued a construction permit for one coal-fired power plant and has proposed to issue a construction permit for another coal-fired power plant. At this point in time, Illinois EPA has found that the permittees have not been able to obtain performance guarantees from equipment manufactures at levels above 90% removal at this time.

The State and local Agency stakeholders, as well as the equipment manufacturers, as part of the October 2002 FACA report, recommend that 90% removal efficiency was appropriate based on their review of pilot plant and large unit testing of new technologies.

Also, various studies, including a U.S. EPA report "Control of Mercury Emissions from Coal-Fired Electric Utility Boilers," which was posted on U.S. EPA's website on February 27, 2004, indicate that these levels of control have been achieved and are projected as achievable in 2010 across all types of units and types of coal.

Rule Should Be Fuel Neutral

We urge U.S. EPA to adopt a rule that treats all types of coal equally in setting the standards for mercury and that requires state-of-the-art control equipment. While the overarching goal of this proposed environmental control program is to greatly reduce the emissions of hazardous mercury, the proposed levels for sub-bituminous and lignite coals would require no, or very minimal, mercury reduction from EGUs burning these coals. In fact, U.S. EPA's own contractor (RTI International) has been quoted as admitting that the proposed rule would necessitate installation of control equipment at 78% of the EGUs using bituminous coal, while only 29% of the EGUs burning sub-bituminous coal and 21% of those burning lignite coals would have to add controls. We also note that U.S. EPA's proposed approach in this proposal to require less mercury reduction from lignite and sub-bituminous coals is counter to the recommendations of its own working group for this issue that met from August 2001 through March 2003 under the Federal Advisory Committee Act (FACA). Moreover, we do not believe the approach that distinguishes between coal rank is either legal or technically supportable. Sections 111 and 112 limit U.S. EPA's authority when developing regulations for a source category to simply distinguishing between the classes, types, and sizes of boilers, or, in other words, they are allowed to make a technical distinction. As has already been discussed, an EGU can burn both the sub-bituminous or bituminous coal with minimal or no change to the boiler. In addition, as some states have found, mercury emissions from sub-bituminous coal decreases with the blending of it with bituminous coal. If U.S. EPA's proposal was fuel neutral, users of sub-bituminous coal may have an incentive to blend with bituminous coal. A similar blending has taken place for years with respect to the Acid Rain and NOx Trading Programs, where users of primarily bituminous coal are blending sub-bituminous coal to meet more stringent NOx and SO_2 emission limits.

Moreover, there does not appear to be a technological issue to prevent EGUs that burn bituminous coal from switching to or blending sub-bituminous coal. Therefore, the proposal provides an incentive that could result in an overall increase in current mercury levels within the State. As illustration, the estimate of 2.99 tons of mercury attributed to the State of Illinois did not account for blending/mixing of coal types and coal switching that resulted in a substantial increase in the use of sub-bituminous coals that has occurred since the implementation of the Acid Rain program. As such, Illinois' mercury emissions from EGUs are approximately 25% higher than U.S. EPA's estimate. With different mercury emission standards for each type of coal, companies will likely continue to experiment with different coal blend scenarios which could further delay the reduction of mercury to the environment. Furthermore, Illinois' mercury emissions could actually increase as EGUs take advantage of less stringent emission limits if they were to switch from bituminous to sub-bituminous coal.

This rulemaking should not provide a justification for power plants that choose to use lignite or sub-bituminous coals to continue to pollute. The provisions of the Clean Air Act and U.S. EPA implementing regulations are basically fuel neutral. Although we note that some minimal attempt was made in the Clean Air Act Title IV Acid Rain program to give relief for EGUs in states that relied more heavily on high-sulfur bituminous coals, the Acid Rain program still had an extremely deleterious effect on bituminous eastern and Mid-western coal industry, although it achieved significant environmental gains. The U.S. EPA mercury reduction rule must also provide a fuel neutral approach to reducing the emissions of mercury.

This approach to fuel neutrality is evidenced by U.S. EPA's recently proposed, but not yet published, Industrial Boiler MACT, which does not distinguish between coal ranks. (40 CFR part 63, subpart DDDD)

The U.S. EPA should establish a fuel neutral approach for mercury reductions that achieves environmental gain without creating additional economic distortions in the coal market. We urge U.S. EPA to recognize the importance of adopting standards that will result in real reductions of mercury to the environment without unfairly pitting the regions of the country against each other. We strongly oppose the proposed approach in reducing mercury emissions from utility boilers based on coal types. The mercury proposal should be uniform for all fuel types nationwide, consistent with the Clean Air Act's policy of fuel neutrality. We urge U.S. EPA to revise the Proposal, as it appears to indirectly promote certain coal fuel types.

Determining Compliance

Under the Mercury Proposal, a company could elect to blend coals from different types and ranks as a means to achieve compliance with the rule. Although, U.S. EPA discussed the possibility of blending different coal ranks (69 *Fed. Reg.* 4674), there is no industry-wide uniform blending procedures. In fact, sources may adopt irregular blending frequencies due to their own economic situation, the coal quality of their supplies, or to achieve their own optimization goals. The determination of the weighted mercury allowable emissions limit would then become a case-by-case compliance determination for most, if not all, EGUs. We believe this lack of specificity by U.S. EPA will lead to an inaccurate accounting of mercury emissions and may well lead to an increase of uncontrolled mercury emissions to the atmosphere. For the aforementioned reasons, determining or verifying compliance could be a very cumbersome procedure. States would face extreme difficulty in enforcing such a rule. Again, Illinois supports a fuel neutral rule.

Technical Issues

As stated previously, we found it very difficult to assess the statistical analyses that were used as the basis for setting the MACT floor values based on the information provided in the *Federal Registers* and in the various supporting materials.

Our concerns regarding the analyses that were used to set the MACT floor include the following: 1) It has not been established that the best performing 12% of sources were selected to establish the MACT floor; 2) Since the testing of emissions units was not random, we cannot be sure that the data used to set the MACT floor properly represents the variability of the mercury emissions; 3) Only one test per unit does not seem sufficient to use as the basis in setting the MACT floor; 4) We cannot tell which emissions variables are most sensitive in determining the MACT floor; and what the model indicated when variability was accounted for; 5) We question why a hot side electro-static precipitator (HESP) was selected as one of the best-controlled sources for setting the MACT floor for sub-bituminous coal; and 6) There was inadequate justification for not examining more control technologies/options in setting the MACT for new sources. These concerns add further to the lack of confidence in the MACT levels values that USEPA has proposed.

Other Hazardous Air Pollutants

We also urge U.S. EPA to take steps to move forward with emissions standards for all non-mercury HAPs that are emitted from EGUs. In its December 2000 "Notice of Regulatory finding for Emissions of HAPs from EGUs", U.S. EPA indicated that a significant number of the 189 HAPs included in the section 112(b) list are being emitted by coal and oil fired utility units. In fact, in the final utility report ("Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units, Final Report to Congress, Volume I", referenced as "Utility Report to Congress") containing the study on exposure and risk assessment from a number of HAPs from EGUs, U.S. EPA estimated that in addition to mercury and nickel, as much as 143,000 tons of hydrogen chloride (HCL), 20,000 tons of hydrogen fluoride and an appreciable tonnage of heavy metals such as arsenic (61 tons), chromium (73 tons), lead (75 tons), acrolein (25 tons) and manganese (164 tons) were emitted to the atmosphere in 1990 from these units. The same report predicted that these HAP emissions would increase during the period of 1990 to 2010.

The Utility Report to Congress recommended that a risk assessment analysis be performed on emissions from coal combustion for the following HAPs: acrolein, arsenic, beryllium, cadmium, chromium, dioxin/furans, radionucleides, hydrogen chloride (HCL), hydrogen fluoride (HF), and lead. Heavy metals like arsenic, nickel, chromium and cadmium are the heavy metals prioritized for further risk assessment because of the higher potential concern for carcinogenic effects. Also recommended for further assessment were hydrogen chloride, hydrogen fluoride and acrolein because these HAPs are of greatest potential concern for public health due to short-term exposure.

Although the preliminary screenings indicate that cancer risks are not high, our concern is based on the fact that U.S. EPA could not eliminate these heavy metals as posing no risk to public health. We believe that U.S. EPA should include emission standards for acid gases, other HAPs (notably arsenic, cadmium, chromium, and lead) and organics (dioxin) for the very same reasons these heavy metals and HAPs were selected as priorities for further risk assessment, i.e., due to their significant level of emissions, persistency in the environment, tendency to bioaccumulate and potential health threat due to short term exposures. Such standards have been adopted in recent Industrial Boiler MACT and MACT standards for municipal solid waste combustors. Treating EGUs the same as industrial boilers is clearly appropriate and scientifically supportable.

Emissions Trading

Illinois has been recognized as a leader in the area of emissions trading, and based on our experience with a number of emissions trading programs for criteria pollutants, we provided supportive comments to U.S. EPA on their proposed interstate trading program as part of the recent Interstate Air Quality Rule (IAQR) proposal. We are very concerned, however, that the proposed emissions trading program for mercury would cause or perpetuate continued fish consumption advisories for our waterbodies. Because of these concerns, we urge U.S. EPA to refrain from including an emissions trading program in its national mercury reduction strategy for electric generating units, unless EGUs wishing to trade can demonstrate that they do not cause or allow continuation of a mercury "hot spot," or U.S. EPA otherwise ensures that a protective base level of mercury reduction from each unit is achieved, and trading only occurs above this protective limit.

Without strict mercury reduction limits, emissions trading could result in an undetected localized mercury "hot spot" due to an EGU that elects not to reduce its emissions. Unlike NAAQS for criteria pollutants (i.e., particulates, nitrogen dioxide, sulfur dioxide, ozone and lead), there are no NAAQS for mercury that must be maintained to protect against localized atmospheric loading and deposition. Furthermore, the number of ambient mercury monitors is very, very small compared to the criteria pollutant-monitoring program throughout the Nation. In Illinois, for example, we are fortunate to have one continuous mercury monitor; many States do not have any. Our air-monitoring network is therefore not adequate to detect a localized ambient mercury "hot spot."

We have particular concerns about the water quality in our local rivers and streams in the Midwest, and even greater concerns about mercury levels in the Lake Michigan. High levels of mercury deposited in our State's waterways have accumulated in fish tissue, resulting in the issuance of advisories to restrict consumption of predator fish caught from Illinois' lakes and streams. A soon to be published study, "Modeling the Atmospheric Transport and Deposition of Mercury to the Great Lakes,"(to be published in "Environmental Research") shows that Midwest EGUs are substantial contributors to mercury in the Great Lakes. A three-year study of precipitation samples collected in Indiana and analyzed by the U.S. Geological Survey has concluded that the mercury concentration in the precipitation is significantly influenced by nearby mercury emitting sources. (Risch, Martin, U.S. Geological Survey, Briefing for Indiana Department of Environmental Management Mercury Workgroup, "Atmospheric Deposition of Mercury in Indiana and Nearby Emission Sources", April 2004.) Local sources must achieve reductions.

In addition to Illinois' general concerns with a trading program, there are two particular provisions of the U.S. EPA proposal that further exacerbate our concerns for "hot spots." The first is the "safety valve" provision that enables sources to buy additional allowances from a future allocation at a price that is preset in the rule. The proposed rule allows borrowing with no interest or penalty, requiring only a reduction in the State's mercury budget for future years. (*See* 69 *Fed. Reg.* 12445, proposed section 60.4143.) A safety valve provision is counter to a market-based approach to reducing emissions. A local mercury "hot spot" could be the result of applying the "safety valve" to a particular plant or group of plants.

The second provision of concern is the one for banking as proposed in section 60.4135. It allows unlimited banking with no flow control. Such a provision will allow sources that may easily comply with the "limits" set for 2010 to bank allowances for 8 years and to push the final compliance date out at least another decade. The federal NOx SIP Call Trading Program avoided this result by adopting a flow control provision that makes older allowances less valuable. Such a mechanism is even more appropriate for this program, where "hot spots" could appear.

Illinois has these additional concerns about the Supplemental Notice to the U.S. EPA proposal. First, it did not include any proposed language for a section 112(n) trading program. Such a program could be fundamentally different in structure than a program promulgated pursuant to section 111. As proposed in the Supplemental Proposal, under section 111 states are given flexibility over allocation issues as long as they meet their budgets, and so long as they meet certain parameters, but similar authority is not specified under a section 112(n) approach. Moreover, it is unclear, given the mandate under section 111(b)(1)(B) that U.S. EPA is required to regulate new sources, how U.S. EPA can require states to regulate "new" EGUs under section 111(d), because this section requires states to regulate "existing" sources. Illinois prefers that if there is a trading program promulgated, it would have the authority to develop its own system for allowance allocation, flow control, banking, and other trading issues.

Second, the Supplemental Notice provides no State budgets for 2010, nor does it indicate when such budgets would be promulgated by U.S. EPA. This is a critical piece of a program, as the State would be required to promulgate rules no later than 2007.

We ask that U.S. EPA not incorporate mercury emissions trading within its national mercury reduction program, and in the alternative, that such a trading program be carefully designed so that U.S. EPA can insure protection of our waters.

Program Consistency

We urge U.S. EPA to make every effort to ensure consistency, especially with respect to compliance deadlines, between the various federal air quality programs, including the mercury reduction program, the Interstate Air Quality Rule (IAQR), the Regional Haze program, and the NAAQS attainment dates. While it is clear that additional reductions from EGUs are warranted and achievable, we must take all available steps to provide the electric power industry with a reasonable degree of certainty regarding future regulatory requirements, especially the timing of these requirements. The industry must be given the opportunity to plan for the most cost-effective set of compliance options.

Conclusion

It is disappointing that U.S. EPA is not proposing the kind of strong federal mercury reduction program that will result in comparable, reliable, equitable and sufficient reductions to allow States to minimize the risk to their citizens and fulfill their obligations under the Clean Air and Clean Water Acts. U.S. EPA has ultimate statutory responsibility, along with the State of Illinois, for assuring that water quality standards are achieved and impaired waters are restored in a timely manner. If the Mercury Proposal is promulgated as proposed under other section 111(d) or 112(n), Illinois is concerned that the significant adverse health impacts from mercury would continue into the next several decades, and we will be unable to provide reasonable assurance (under the Clean Water Act TMDL rule) that water quality standards will be achieved. Instead, U.S. EPA will be looking to us for a better demonstration of reasonable assurance, and we will ultimately need to develop state-level requirements to solve what is a national-scale water quality problem.

We strongly urge U.S. EPA to establish a mercury reduction program through a MACT standard under section 112(d) and to adopt a fuel neutral program as mandated by the Clean Air Act. We urge a strict program, which results in a mercury limit for all existing coal-fired units of 2 lb/TBTU or an 80% reduction in 2010. New sources should be required to reduce emissions by 90%.

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MMWR

Weekly

March 02, 2001 / 50(08);140-3

Blood and Hair Mercury Levels in Young Childr and Women of Childbearing Age --- United State 1999

Mercury (Hg), a heavy metal, is widespread and persistent in the environment. Exposure to hazardous I cause permanent neurologic and kidney impairment (*1--3*). Elemental or inorganic Hg released into the becomes methylated in the environment where it accumulates in animal tissues and increases in concen through the food chain. The U.S. population primarily is exposed to methylmercury by eating fish. Met exposures to women of childbearing age are of great concern because a fetus is highly susceptible to ad This report presents preliminary estimates of blood and hair Hg levels from the 1999 National Health a Examination Survey (NHANES 1999) and compares them with a recent toxicologic review by the Nati Research Council (NRC). The findings suggest that Hg levels in young children and women of childbe generally are below those considered hazardous. These preliminary estimates show that approximately women have Hg levels within one tenth of potentially hazardous levels indicating a narrow margin of s some women and supporting efforts to reduce methylmercury exposure.

CDC's NHANES is a continuous survey of the health and nutritional status of the U.S. civilian, noninst population with each year of data constituting a representative population sample. A household intervie physical examination were conducted for each survey participant. During the physical examination, blo collected by venipuncture for all persons aged ≥1 year and hair samples, consisting of approximately 1(were cut from the occipital position of the head of children aged 1--5 years and women aged 16--49 yea blood specimens were analyzed for total Hg and inorganic Hg for children aged 1--5 years and women years by automated cold vapor atomic absorption spectrophotometry in CDC's trace elements laborator detection limit was 0.2 parts per billion (ppb) for total Hg and 0.4 ppb for inorganic Hg (*4*). Hairs of 0.6 cm) closest to the scalp (approximately 1 month's growth) were analyzed for total Hg concentration usi atomic fluorescence spectroscopy (*5*). The limit of detection for total Hg in hair varied by analytic batcl maximum limit of detection (0.1 parts per million [ppm]) was used in these analyses. Blood Hg levels l limit of detection were assigned a value equal to the detection limit divided by the square root of two fo of geometric mean values.

The geometric mean total blood Hg concentration for all women aged 16--49 years and children aged 1 1.2 ppb and 0.3 ppb, respectively; the 90th percentile of blood Hg for women and children was 6.2 ppb respectively (Table 1). Almost all inorganic Hg levels were undetectable; therefore, these measures indi methylmercury levels. The 90th percentile of hair Hg for women and children was 1.4 ppm and 0.4 ppn respectively. Geometric mean values were not calculated for hair Hg values.

Reported by: Center for Food Safety and Applied Nutrition, Food and Drug Administration. US Enviro Protection Agency. National Energy Technology Laboratory, Dept of Energy. National Marine Fisheri

Laboratory, National Oceanic and Atmospheric Administration. National Center for Health Statistics; , Center for Environmental Health, CDC.

Editorial Note:

The NHANES1999 blood and hair Hg data are the first nationally representative human tissue measure: population's exposure to Hg. Previous estimates of methylmercury exposure in the general population v exposure models using fish tissue Hg concentrations and dietary recall survey data (*1*). The NRC reviev guidance to the Environmental Protection Agency (EPA) for developing an exposure reference dose foı methylmercury (i.e., an estimated daily exposure that probably is free of risk for adverse effects over th person's life) (*3*). The NRC report recommended statistical modeling of results from an epidemiologic s conducted in the Faroe Islands near Iceland, where methylmercury exposures are high because of the la of seafood eaten by the local population. Results of this study were used to calculate a benchmark dose estimate of a methylmercury exposure in utero associated with an increase in the prevalence of abnorm: cognitive function tests in children. The lower 95% confidence limit of the BMD (BMDL*) was recomı calculate the EPA reference dose. The NRC committee recommended a BMDL of 58 ppb Hg in cord bl (corresponding to 12 ppm Hg in maternal hair) (*3*). In the NHANES 1999 sample, there were no measu blood values ≥58 ppb or hair values ≥12 ppm. A margin-of-exposure analysis (i.e., an evaluation of the BMDL to estimated population exposure levels) showed ratios of <10 when comparing BMDL with NI estimates of the 90th percentile for blood and hair Hg levels in women of childbearing age. Margin-of-ε measures of this magnitude indicate a narrow margin of safety (*3*) and suggest that efforts aimed at decı human exposure to methylmercury should continue.

The findings in this study are subject to at least three limitations. First, the ratio of Hg in cord and mateı uncertain. The NRC committee summarized some studies that suggest that cord blood values may be 2(higher than corresponding maternal blood levels. However, other studies suggest that the ratio is closer therefore, the NHANES values may not be directly comparable to BMDL recommended by NRC. Seco NHANES cannot provide estimates of Hg exposure in certain highly exposed groups (e.g., subsistence and others who eat large amounts of fish). Published data from studies of highly exposed U.S. populatio that some persons attain Hg tissue levels above BMDL (*1*). Third, the sample size of NHANES 1999 w the 1999 survey was conducted in only 12 locations. More data are needed to confirm these findings.

The long-term strategy for reducing exposure to Hg is to lower concentrations of Hg in fish by limiting into the atmosphere from burning mercury-containing fuel and waste and from other industrial processe basis of data from EPA's National Toxics Inventory, air emissions of Hg decreased approximately 21% -1996, largely because of regulations for waste incineration (*7*). EPA expects this trend to continue as rı implemented for waste incineration and chlorine production facilities and are developed for electric pov (*8,9*). Fish is high in protein and nutrients and low in saturated fatty acids and cholesterol and should be an important part of the diet. The short-term strategy to reduce Hg exposure is to eat fish with low Hg lı avoid or to moderate intake of fish with high Hg levels. State-based fish advisories and bans identify fis contaminated by Hg and their locations and provide safety advice (http://www.epa.gov/ost/fish†). The F Drug Administration advises that pregnant women and those who may become pregnant should not eat swordfish, king mackerel, and tile fish known to contain elevated levels of methylmercury. Information at http://www.fda.gov/bbs/topics/ANSWERS/2001/advisory.html †.

U.S. population estimates of Hg tissue levels by race/ethnicity, region, and fish consumption will becon after 2 additional years of NHANES data collection. NHANES will provide the opportunity to measure levels and to monitor the effectiveness of continuing efforts to reduce methylmercury exposure in the U population.

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*A BMD of 85 ppb Hg in cord blood or 17 ppm Hg in maternal hair was estimated to result in an increase in the proportion scores on the Boston Naming Test for children exposed in utero from an estimated background prevalence of 5% to a preval (*6*). BMDL recommended by NRC is the lower 95% confidence bound of the BMD.

† References to sites of nonCDC organizations on the World-Wide Web are provided as a service to *MMWR* readers and do imply endorsement of these organizations or their programs by CDC or the U.S. Department of Health and Human Services. responsible for the content of pages found at these sites.

Table 1

TABLE 1. Selected percentiles and geometric means of blood and hair mer (Hg) concentrations for children aged 1–5 years and women aged 16–49 ye National Health and Nutrition Examination Survey, United States, 1999

		Geometric		Selected percentiles (95% CI*)								
	No.	mean	(95% CI)	10th		25th		50th		75th		
Blood Hg†												
Children	248	0.3	(0.2–0.4)	<LOD§		<LOD		0.2	(0.2–0.3)	0.5	(0.4–0.8)	1
Women	679	1.2	(0.9–1.6)	0.2	(0.1–0.3)	0.5	(0.4–0.7)	1.2	(0.8–1.6)	2.7	(1.8–4.5)	6
Hair Hg¶												
Children	338	—**		<LOD		<LOD		<LOD		0.2	(0.1–0.4)	0
Women	702	—		<LOD		<LOD		0.2	(0.2–0.3)	0.5	(0.4–0.8)	1

* Confidence interval.
† Parts per billion.
§ Limit of detection.
¶ Parts per million.
** Not calculated. Proportion <LOD too high to be valid.

Return to top.

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file: PState Air Permit

Peabody

Dianna Tickner
03/23/2006 04:54 PM

To "Laurel Kroack" <Laurel.Kroack@epa.state.il.us>
cc Colin M. Kelly/STL/Peabody@PeabodyEnergy
bcc
Subject Technology Extension for Mercury

Laurel,
Just wanted to let you know that the Temporary Technology Based Extension is very helpful in addressing the Prairie State Generating Station concerns. We just have a few comments/clarifications for your consideration.
Thanks.
Dianna

IL Mercury reg Temporary Technology Based ext proposal 3-21-06_.doc

3/23~~1~~/2006

OVERVIEW OF POSSIBLE PROVISIONS FOR A TEMPORARY TECHNOLOGY-BASED EXTENSION (TTBE)

Overview:

To qualify for the Temporary Technology-Based Extension (TTBE), a source must meet the specific criteria identified in the rule. The most significant criterion is use of an appropriate configuration of control devices for effective control of mercury emissions, given the type of coal being fired and the control devices already installed on the unit. (Refer to Tables 1 and 2.) For existing units, the specified configuration is generally use of activated carbon injection for control of mercury emissions along with an appropriate particulate matter control device to assure the effectiveness of carbon injection. In addition, during Phase 1 of the program, existing units equipped with an appropriate suite of control devices for effective control of mercury emissions by co-benefit would be eligible for an extension. For a new unit, the specified configurations for an extension require use of activated carbon for control of mercury emissions along with use of appropriate control devices to minimize emissions by co-benefit.

There needs to be an express waiver during the extension. For example, "If the applicant demonstrates compliance with the five criteria specified under "Contents of a Request," the mercury standards would not apply or the deadline for compliance would be extended so long as the criterion for the extension are met.

Process:

A source must submit a timely application for a temporary technology-based extension, containing information showing that the relevant criteria for such an extension are met. If the application shows that all relevant criteria are met, i.e., the application is not found to be incomplete within a nominal period of time~~,~~ the source can rely on the extension until the Agency takes final action on the application. (We believe "the nominal period of time "for agency review of the application must be defined ie, 30 days)

The Illinois EPA will conduct a technical review to determine whether an extension is given or to establish whether any unit-specific requirements should accompany the extension too assure that the source undertakes optimization measures as required by criterion 3 and that state-of-the-art mercury control be applied as required by criterion 5. There is no opportunity for public participation in the process by which an extension becomes effective.

Timing and Duration

The temporary technology-based extension would be available through December 2018, that is, through Phase 1 and up to the first five years of Phase 2 of the mercury control program. A source would have to submit its application for an extension to the

Illinois EPA no later than three months before compliance needs to be demonstrated. Accordingly, an application for an extension for an existing unit must be submitted by no later than March 31, 2010 for Phase 1 of the mercury control program, and by no later than September 30, 2012 for Phase 2 of the program. <u>What happens if the source has done everything after extension period and still doesn't meet the limits?</u>

If a source obtains an extension for a unit for Phase 1 of the program, the source must reapply for the extension for Phase 2. The source must also reapply for the extension if there will be a change in the control device configuration of the unit and the source plans to change its practices for control of mercury emissions based on the change to the control device configuration.

Contents of a Request

A request for a temporary technology-based extension for a unit must include information showing that the applicable criteria for such an extension are met for the unit, as follows:

1. The owner or operator of the unit submits a formal request for the extension that: 1) Explains why an extension is being requested: 2) Describes the measures that have been taken for control of mercury emissions; 3) Provides a detailed discussion of the factors that currently prevent more effective control of the mercury emissions of the unit, with a summary of relevant mercury emission data for the unit; and 4) Includes a copy of the current action plan describing the measures that will be taken during the term of the extension to improve control of mercury emissions.

2. The configuration of control devices on the unit is one that qualifies for an extension, as listed in Table 1 or 2, and the activated carbon injection system, if one is required, has been properly installed. An alternative sorbent may be used in place of the halogenated activated carbon if the source demonstrates that the alternative sorbent either: 1) Has at least the same effectiveness for control of mercury as halogenated activated carbon; or 2) Will be used in a manner to provide equal or better effectiveness for control of mercury as would be achieved with halogenated activated carbon.

3. For a unit for which injection of halogenated activated carbon is required, injection is occurring at optimal rate(s). For this purpose, a source must either inject halogenated activated carbon at a rate of at least 3 and 10 pounds per million cubic feet of actual exhaust for units fired on sub-bituminous and bituminous coal, respectively, or at rate(s) that reflect the maximum practicable degree of mercury removal, based upon a unit-specific evaluation of the relationship between the injection rate and the removal of mercury, to identify the injection rate at which increased usage of halogenated activated carbon no longer provides proportionate improvements in mercury removal.

4. The owner or operator of the unit has an action plan identifying specific measures that will be taken during the term of the extension to improve control of the mercury emissions from the unit. This plan shall address measures such as evaluation of

alternative forms or sources of activated carbon, changes to the injection system, changes to operation of the unit that affect the effectiveness of mercury absorption and collection, changes to the particulate matter control device to improve the performance of, and changes to other emission control devices. For each measure contained in the plan, the plan shall provide a detailed description of the specific actions that are planned, the reason that the measure is being pursued and the range of improvement in control of mercury that is expected, and the factors that affect the timing for carrying out the measure, with the current schedule for the measure.

5. The owner or operator of a unit utilizing halogenated activated carbon injection (ACI) must include a demonstration that halogenated ACI remains the state-of-the-art for mercury control. If new developments in ACI occur that demonstrate a higher level of mercury control (e.g., use of more effective sorbents), or if other mercury control technologies develop that remove mercury at a cost similar to the cost of halogenated ACI in 2006 dollars, the owner or operator must agree to utilize the more effective means of ACI or other control technology within a reasonable time frame. The provision "if other mercury control technologies develop" causes us concern that it could be a continual moving target and cause great concern with the projects lenders that they could potentially be exposed to hundreds of millions of costs for retrofit if original technology does not work to the regulation level. If this provision is intended just for different sorbents or chemical additives that is acceptable. However, a requirement to install totally new hardware technology, for example if it were determined something like Powerspan was state of the art, it might be impossible to incorporate that technology into the design once the plant is constructed with Table 2 required technology. The costs for the new hardware might be similar, but millions would have already been invested in the original approved technology increasing the plants cost dramatically. We recommend removing "demonstration of state of the art mercury control" and references to "other mercury control technologies" unless there is further clarification on limitations.

Consequences of Obtaining an Extension

Sources that obtain a temporary technology-based extension for a unit would have to continue to operate the unit in accordance with the technology-based criteria that were the basis of the extension, including implementing an action plan for the unit for the period of time that extension is in place. Units operating under an extension could not be included in any compliance demonstrations involving multiple units. When a source determines that a unit can comply with the applicable emissions standards for mercury, the source would notify the Illinois EPA that it is terminating the extension for the unit. Thereafter, the source would no longer be required to implement an action plan for the unit and the unit could be included in compliance demonstrations involving multiple units in subsequent months.

A source that is operating a unit under a temporary technology based extension would be required to submit annual reports describing the activities that are conducted for the unit to further improve control of mercury emissions, including significant measures that were taken during the past year, significant activities that are planned for the current year, and any changes to the action plans for the unit, with explanation.

Table 1: Required Configuration of Control Devices for Existing Units

Primary Type of Coal	Phase of Program	Minimum Control Configuration
Subbituminous	Available for Both Phase 1 and Phase 2	Cold-side Electrostatic Precipitator or Fabric Filter and Injection of Halogenated Activated Carbon
Bituminous	Available for Both Phase 1 and Phase 2	Cold-side Electrostatic Precipitator or Fabric Filter and Injection of Halogenated Activated Carbon
	Available for Phase 1 only	Selective Catalytic Reduction (SCR) System (located prior to the particulate matter control device) and SO_2 Scrubber
		Fluidized Bed Boiler: Selective Non-Catalytic Reduction (SNCR) System and Fabric Filter

Table 2: Required Configuration of Control Devices for New Units

Primary Type of Coal	Minimum Control Configuration
Subbituminous	Pulverized Coal Boiler: SCR, SO_2 Control Device, Fabric Filter, and Injection of Halogenated Activated Carbon
	Fluidized Bed Boiler: SNCR, Supplemental SO_2 Control System, Fabric Filter and Injection of Halogenated Activated Carbon
Bituminous	Pulverized Coal Boiler: SCR, High-efficiency PM Control Device (i.e., subject to a limit of no more than 0.015 lb/million Btu, as measured by USEPA Method 5), SO_2 Scrubber, and Injection of Halogenated Activated Carbon
	Fluidized Bed Boiler: SNCR, Supplemental SO_2 Control System, Fabric Filter and Injection of Halogenated Activated Carbon
	Unit Firing Fuel Gas Produced by Coal Gasification: Processing of the Raw Fuel Gas prior to Combustion With Systems for PM and Sulfur Removal and with Activated Carbon for Removal of Mercury.