From: Blakley, Robert

Sent: Tuesday, January 06, 2009 1:31 PM

To: 'Robert Johnson'; Volker Rummenhohl

Cc: Weilert, Carl; Voss, Steve

Subject: RE: Hypothetical TE-SCR Cost Estimate

Volker & Bob –

We have been asked by one of our northern Midwest clients to perform a BACT cost-effectiveness analysis assuming that a custom tail-end SCR system could be retrofit on each of two coal-fired boilers.

We need help in developing capital cost and O&M cost estimates for retrofitting TESCR to existing units that use dry ESPs with lime-based wet FGD systems upstream. The normal operating and maintenance costs will be based on less than maximum design boiler heat input and flue gas flow conditions upon which the TESCRs would be designed for.

We will need advice as to what assumptions would be included in the process design for flue gas reheat, amount of catalyst, unit catalyst cost, frequency of catalyst replacement or washing, length of time periodic catalyst changeout, flue gas pressure drop from scrubber outlet to chimney inlet, and NOx reduction and ammonia consumption performance targets.

We will need the above estimates in a very short time period – before the end of January, with preliminary numbers by mid-January.

We would also like to get some idea as to the amount of calendar months required for implementation: scoping, vendor identification, investigation, design, procurement, construction, startup and commissioning, and outage time required for the initial installation tie-ins.

We can provide data for fuel, boiler heat input, NOx emissions and excess air/flue gas volume from the boiler outlet, sulfur dioxide removal by the wet FGD scrubber, and particulate loading.

If you have a spreadsheet, I can fill-in, or we can give you what we have as mentioned above.

We will work out the contractual agreement as we proceed, if that is okay.

Let me know how we can get this going.

Bob Blakley

Blakley, Robert

From: Robert Johnson [RJohnson@ftek.com]
Sent: Wednesday, January 07, 2009 8:50 AM
To: Blakley, Robert; Volker Rummenhohl
Cc: Weilert, Carl; Voss, Steve
Subject: RE: Hypothetical TE-SCR Cost Estimate

Bob,
Volker and I can support you on this. We can quickly run a mass balance once we get the process data.
I will be at Burns & McDonnell tomorrow; perhaps we can get together briefly to discuss.
Thanks, Bob

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Tuesday, January 06, 2009 1:31 PM
To: Robert Johnson; Volker Rummenhohl
Cc: Weilert, Carl; Voss, Steve
Subject: RE: Hypothetical TE-SCR Cost Estimate

Volker & Bob –

We have been asked by one of our northern Midwest clients to perform a BACT cost-effectiveness analysis assuming that a custom tail-end SCR system could be retrofit on each of two coal-fired boilers.

We need help in developing capital cost and O&M cost estimates for retrofitting TESCR to existing units that use dry ESPs with lime-based wet FGD systems upstream. The normal operating and maintenance costs will be based on less than maximum design boiler heat input and flue gas flow conditions upon which the TESCRs would be designed for.

We will need advice as to what assumptions would be included in the process design for flue gas reheat, amount of catalyst, unit catalyst cost, frequency of catalyst replacement or washing, length of time periodic catalyst changeout, flue gas pressure drop from scrubber outlet to chimney inlet, and NOx reduction and ammonia consumption performance targets.

We will need the above estimates in a very short time period – before the end of January, with preliminary numbers by mid-January.

We would also like to get some idea as to the amount of calendar months required for implementation: scoping, vendor identification, investigation, design, procurement, construction, startup and commissioning, and outage time required for the initial installation tie-ins.

We can provide data for fuel, boiler heat input, NOx emissions and excess air/flue gas volume from the boiler outlet, sulfur dioxide removal by the wet FGD scrubber, and particulate loading.

If you have a spreadsheet, I can fill-in, or we can give you what we have as mentioned above.

We will work out the contractual agreement as we proceed, if that is okay.

Let me know how we can get this going.

Bob Blakley

Blakley, Robert

From: Robert Johnson [RJohnson@ftek.com]
Sent: Monday, January 12, 2009 12:03 PM
To: Blakley, Robert; Volker Rummenhohl
Cc: Weilert, Carl; Voss, Steve
Subject: RE: Hypothetical TE-SCR Cost Estimate

Bob,
In order to run the mass balance for the TE SCR, we need the following process data:
Flue gas volumetric flow rate
Flue gas mass flow rate
Flue gas composition downstream of the FGD system
Flue gas temperature
NOx reduction requirements
Maximum SO2 oxidation rate

Once we get started, we'll let you know if we need anything else.

From this, we can estimate reheat requirements, catalyst volume, pressure drop, NH3 consumption.

Best Regards, Bob

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Tuesday, January 06, 2009 1:31 PM
To: Robert Johnson; Volker Rummenhohl
Cc: Weilert, Carl; Voss, Steve
Subject: RE: Hypothetical TE-SCR Cost Estimate

Volker & Bob –

We have been asked by one of our northern Midwest clients to perform a BACT cost-effectiveness analysis assuming that a custom tail-end SCR system could be retrofit on each of two coal-fired boilers.

We need help in developing capital cost and O&M cost estimates for retrofitting TESCR to existing units that use dry ESPs with lime-based wet FGD systems upstream. The normal operating and maintenance costs will be based on less than maximum design boiler heat input and flue gas flow conditions upon which the TESCRs would be designed for.

We will need advice as to what assumptions would be included in the process design for flue gas reheat, amount of catalyst, unit catalyst cost, frequency of catalyst replacement or washing, length of time periodic catalyst changeout, flue gas pressure drop from scrubber outlet to chimney inlet, and NOx reduction and ammonia consumption performance targets.

We will need the above estimates in a very short time period – before the end of January, with preliminary numbers by mid-January.

We would also like to get some idea as to the amount of calendar months required for implementation: scoping, vendor identification, investigation, design, procurement, construction, startup and commissioning, and outage time required for the initial installation tie-ins.

We can provide data for fuel, boiler heat input, NOx emissions and excess air/flue gas volume from the boiler outlet, sulfur dioxide removal by the wet FGD scrubber, and particulate loading.

If you have a spreadsheet, I can fill-in, or we can give you what we have as mentioned above.

We will work out the contractual agreement as we proceed, if that is okay.

Let me know how we can get this going.

Bob Blakley

From: Blakley, Robert
Sent: Tuesday, January 13, 2009 11:17 AM
To: 'Robert Johnson'; 'Volker Rummenhohl'
Cc: Weilert, Carl; Voss, Steve
Subject: RE: Hypothetical TE-SCR Cost Estimates

Volker & Bob –

One process parameter I did not mention that should be considered in the TESCR system design basis is the outlet gas temperature going to the stack, after the GGH on the back-end of the TESCR.

The new chimney that is being constructed for Unit 2 will have a fiberglass-reinforced plastic liner for the flue gas, and we have advised the chimney vendor that the design temperature range is 130 to 200 degrees F (continuous), with a maximum excursion to 350 degrees F for 15 consecutive minutes (transient condition due to FGD system malfunction).

The existing chimney being retrofit for Unit 1 currently has a metal liner that may receive added corrosion protection using alloy metal "wallpaper" lining or borosilicate glass block that is capable of sustained operation up to 200 degrees F, with higher excursions for short durations, similar to Unit 2's case.

Please advise a time-frame when you think that you will have a preliminary design basis and cost numbers.

Bob Blakley

From: Robert Johnson [RJohnson@ftek.com]
Sent: Friday, January 16, 2009 1:54 PM
To: Blakley, Robert
Subject: RE: Hypothetical TE-SCR Cost Estimates

Bob,
Volker and I have run our initial mass balance, but we need some more time over the weekend to review it.
I will send you comments on Monday.
Thanks, Bob

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Thursday, January 15, 2009 9:47 AM
To: Robert Johnson; Volker Rummenhohl
Cc: Weilert, Carl; Voss, Steve
Subject: RE: Hypothetical TE-SCR Cost Estimates

Bob & Volker –

We need review of our assumed TESCR catalyst replacement plan, saved as an Excel spreadsheet <MRYS TESCR Catalyst Mgt (BMcD draft 1-15-09).xls> at the new ft site:

As part of the BACT cost effectiveness analysis, we also need to know what to assume for catalyst volume per layer, and unit cost (labor & materials) assumed to be required per replacement layer.

Thanks,

Bob Blakley

Assumed TESCR Catalyst Replacement Schedule (assuming wet ESP / low frequency)				Assumed TE SCR catalyst (85% removal) without wet ESP upstream replacement schedule every 8000 hours (1 year)		
starting Jan.	Year	Layer	# of layers	# of layers	Layer	3 new layers from initial onset, Fall 2014 major outage
2015	0		0	1	add bottom	new, add after 1 year in Fall 2015 outage
2016	1		0	1	replace top	after 2 yrs, add new layer in Fall 2016 outage
2017	2	add bottom	1	1	replace mid-upper	after 3 yrs, add new layer in Fall 2017 outage
2018	3		0	2	replace top, mid-lower	after 2 yrs & 4 yrs, add new layers in Fall 2018 outage
2019	4		0	1	replace bottom	after 4 yrs, add new layer in Fall 2019 outage
2020	5	replace top	1	2	replace top, mid-upper	after 2 yrs & 3 yrs, add new layers in Fall 2020 outage
2021	6		0	0	clean only	
2022	7		0	2	replace top, mid-lower	after 2 yrs & 4 yrs, add new layers in Fall 2022 outage
2023	8	replace mid	1	2	replace bottom, mid-upper	after 4 yrs & 3 yrs, add new layers in Fall 2023 outage
2024	9		0	1	replace top	after 2 yrs, add new layer in Fall 2024 outage
2025	10		0	0	clean only	
2026	11	replace bottom	1	3	replace top, mid-upper, mid lower	after 2 yrs, 3 yrs & 4 yrs, add new layers in Fall 2026 outage
2027	12		0	1	replace bottom	after 4 yrs, add new layer in Fall 2027 outage
2028	13		0	1	replace top	after 2 yrs, add new layer in Fall 2028 outage
2029	14	replace top	1	1	replace mid-upper	after 3 yrs, add new layer in Fall 2029 outage
2030	15		0	2	replace top, mid-lower	after 2 yrs & 4 yrs, add new layers in Fall 2030 outage
2031	16		0	1	replace bottom	after 4 yrs, add new layer in Fall 2031 outage
2032	17	replace mid	1	2	replace top, mid-upper	after 2 yrs & 3 yrs, add new layers in Fall 2032 outage
2033	18		0	0	clean only	
2034	19		0	3	replace top, mid-upper, mid lower	after 2 yrs, 3 yrs & 4 yrs, add new layers in Fall 2034 outage
2035	20	replace bottom	1	1	replace bottom	after 4 yrs, add new layer in Fall 2035 outage
		total	7	28		
		avg per yr	0.35	1.40		

Assumed TESCR catalyst Replacement Schedule (assuming wet ESP / low frequency)				Assumed TE SCR catalyst (85% removal) without wet ESP upstream replacement schedule every 8000 hours (1 year)		
starting Jan.	Year	Layer	# of layers	# of layers	Layer	3 new layers from initial onset, Fall 2013 major outage
2014	0		0	1	add bottom	new, add after 1 year in Fall 2014 outage
2015	1	add bottom	0	1	replace top	after 2 yrs, add new layer in Fall 2015 outage
2016	2		1	1	replace mid-upper	after 3 yrs, add new layer in Fall 2016 outage
2017	3	replace top	0	2	replace top, mid-lower	after 2 yrs & 4 yrs, add new layers in Fall 2017 outage
2018	4		0	1	replace bottom	after 4 yrs, add new layer in Fall 2018 outage
2019	5	replace mid	1	2	replace top, mid-upper	after 2 yrs & 3 yrs, add new layers in Fall 2019 outage
2020	6		0	0	clean only	
2021	7		0	2	replace top, mid-lower	after 2 yrs & 4 yrs, add new layers in Fall 2021 outage
2022	8		1	2	replace bottom, mid-upper	after 4 yrs & 3 yrs, add new layers in Fall 2022 outage
2023	9		0	1	replace top	after 2 yrs, add new layer in Fall 2023 outage
2024	10		0	0	clean only	
2025	11	replace bottom	1	3	replace top, mid-upper, mid lower	after 2 yrs, 3 yrs & 4 yrs, add new layers in Fall 2025 outage
2026	12		0	1	replace bottom	after 4 yrs, add new layer in Fall 2026 outage
2027	13		0	1	replace top	after 2 yrs, add new layer in Fall 2027 outage
2028	14	replace top	1	1	replace mid-upper	after 3 yrs, add new layer in Fall 2028 outage
2029	15		0	2	replace top, mid-lower	after 2 yrs & 4 yrs, add new layers in Fall 2029 outage
2030	16		0	1	replace bottom	after 4 yrs, add new layer in Fall 2030 outage
2031	17	replace mid	1	2	replace top, mid-upper	after 2 yrs & 3 yrs, add new layers in Fall 2031 outage
2032	18		0	0	clean only	
2033	19		0	3	replace top, mid-upper, mid lower	after 2 yrs, 3 yrs & 4 yrs, add new layers in Fall 2033 outage
2034	20	replace bottom	1	1	replace bottom	after 4 yrs, add new layer in Fall 2034 outage
		total	7	28		
		avg per yr	0.35	1.40		

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Friday, January 23, 2009 9:58 AM
To: Robert Johnson; Volker Rummenhohl
Cc: Weilert, Carl; Blackwood, Dave; Voss, Steve
Subject: RE: Mass Balance for Hypothetical SCR Installation

Bob & Volker –

Several items to discuss and consider:

1. The U2 FGD absorber vessels (two in parallel configuration) are not designed for 14.5 in. w.g. internal pressure; I believe they have a much lower limit; operationally it is around 4 in. w.g., but I do not know the exact design value. We are looking into hiring a company that can perform a finite element analysis of the absorber vessels, but that will not be started for several months from now. I assume this means that a booster fan will be needed after the FGD GGH, upstream of the SCR GGH, to overcome the pressure drops across the GGHs.
2. We have assumed (and Minnkota is directing us to do so) that the source of heat for the final reheating of the flue gas downstream of the SCR GGH and upstream of the reactors should be fired natural gas or propane, not steam. So the effluent of the direct-fired burner(s) and the associated NOx emissions also must be accounted for in the reactor design and NOx removal. Conservatively, burners should be assumed to be supplied with ambient air for combustion and emit 0.1 lb/mmBtu (per million BTU), unless this is not feasible or there are other reasons to change this assumption.
3. I don't know if this makes a difference, but Minnkota is expecting to store liquid urea concentrate (40-50% solution) on-site as the NOx removal reagent, and so some sort of conversion process will be needed to supply ammonia to the reactors. The plant site does not have direct rail access, so all consumable materials have to be transported by tanker trailer to be offloaded near the U2 boiler building.

We will need a similar preliminary mass balance for a low-dust SCR configuration for Unit 2, as well as both low-dust and tail-end SCRs for Unit 1.

We can arrange a phone conference for Monday to discuss. Carl will be back late tonight. We also need the numbers on catalyst volume and changeout frequency and costs.
Dave Blackwood is leading the scope definition and cost estimating effort from our Development Engineering department here in our Energy group.

We appreciate the information and will continue to work on this in a parallel-path effort. We can discuss this on Monday. Please let us know your availability for a phone conference or visit.

Bob Blakley

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Friday, January 23, 2009 8:10 AM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: Mass Balance for Hypothetical SCR Installation

Bob,
Attached are a Mass Balance and PFD for a Hypothetical Tail End SCR for your review.
Please note:
1. 2 SCR reactors will be required for the installation;
2. The PFD denotes flue gas mass flow in kg/hr and temperature in degrees C. You can identify the specific process stream (noted in blue) and see this information converted into lb/hr and degrees F on the Mass Balance sheet.

We are still evaluating this and will provide more information later today.
Thanks, Bob

Robert E. Johnson
Fuel Tech, Inc
(913) 897 0727
<<22Jan09_TailEnd_PFDRev1.pdf>> <<22Jan09_TailEnd_MBRev1.pdf>>

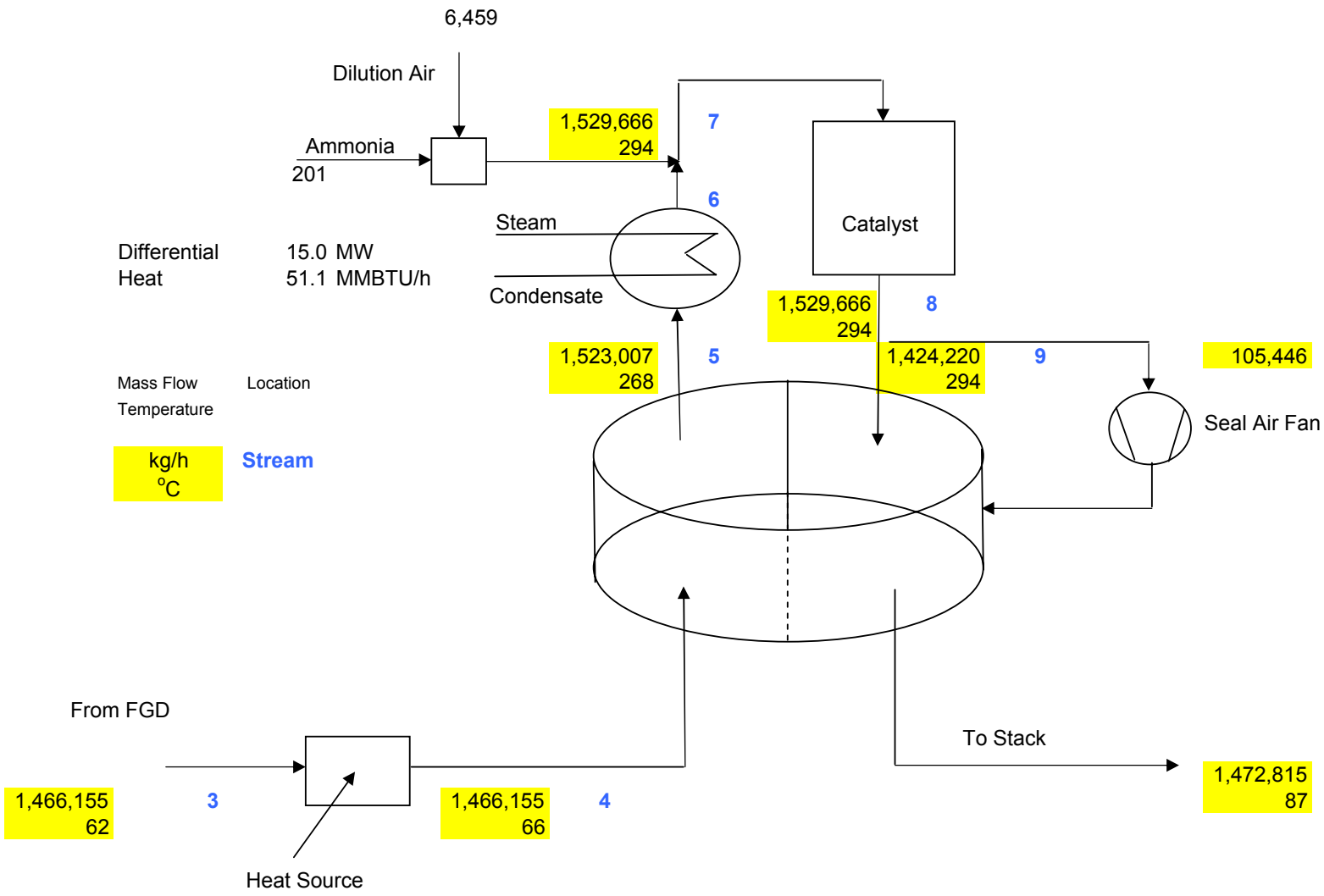
MRY 2		Input Data	3	4	5	6	7	8	9	10	11	14	15	17	14 Reacted		
		FGD Outlet	FGD Outlet	GGH inlet	GGH outlet	Steam HE out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Ammonia	Dilution Air	Purge+Scavange			
Volumetric flow rate vol.	Nm^3/h		1,180,582	1,180,582	1,226,360	1,226,360	1,231,634	1,231,766	1,146,942	1,186,234	1,186,234	263	4,997	84,927		Nm^3/h	Volumetric flow rate vol.
Volumetric flow rate vol.	scfm		744,304	744,304	773,165	773,165	776,490	776,573	723,096	747,868	747,868	166	3,150	53,543		scfm	Volumetric flow rate vol.
Volumetric flow rate vol.	acfm		820,913	820,913	1,394,069	1,469,126	1,474,667	1,485,560	1,384,940	917,742	917,742					acfm	Volumetric flow rate vol.
Mass Flow	kg/h		1,466,155	1,466,155	1,523,007	1,523,007	1,529,666	1,529,666	1,424,220	1,472,815	1,472,815	201	6,459	105,446	201	kg/h	Mass Flow
Mass Flow	lb/hour		3,229,416	3,229,416	3,354,640	3,354,640	3,369,309	3,369,309	3,137,049	3,244,085	3,244,085	442	14,227	232,260	442	lb/hour	Mass Flow
Temperature	Degree F	143	143	150	515	565	562	562	562	188	188					Degree F	Temperature
Temperature	Degree C		62	66	268	296	294	294	294	87	87					Degree C	Temperature
Pressure	iwg		14.5	13.5	10	9	8	5	4.5	0	0						Pressure
Composition																	Composition
Nitrogen	Vol-parts		0.6346	0.6346	0.6346	0.6346	0.6351	0.6354	0.6354	0.6352	0.6352		0.7809		0.2999	Vol-parts	Nitrogen
Carbon di oxide	Vol-parts		0.1063	0.1063	0.1063	0.1063	0.1058	0.1058	0.1058	0.1058	0.1058		0.0003			Vol-parts	Carbon di oxide
Oxygen	Vol-parts		0.0496	0.0496	0.0497	0.0497	0.0503	0.0502	0.0502	0.0501	0.0501		0.2095			Vol-parts	Oxygen
Moisture	Vol-parts		0.2091	0.2091	0.2091	0.2091	0.2082	0.2085	0.2085	0.2088	0.2088				0.7001	Vol-parts	Moisture
Sulfur di oxide	Vol-parts		0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001					Vol-parts	Sulfur di oxide
Sulfur tri oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						
Nitrogen oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						
Nitrogen di oxide	Vol-parts		0.0003	0.0003	0.0002	0.0002	0.0002	0.0000	0.0000	0.0000	0.0000					Vol-parts	Nitrogen di oxide
Argon	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0093				
Ammonia	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000						
Total			1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000		1.0000		1.0000		Total
Volumetric Flow			0														Volumetric Flow
Nitrogen	Nm^3/h		749,220	749,220	778,316	778,316	782,218	782,610	728,717	753,514	753,514		3,902	53,947	64	Nm^3/h	Nitrogen
Carbon di oxide	Nm^3/h		125,507	125,507	130,345	130,345	130,347	130,347	121,371	125,508	125,508		1	8,986		Nm^3/h	Carbon di oxide
Oxygen	Nm^3/h		58,606	58,606	60,904	60,904	61,951	61,820	57,563	59,391	59,391		1,047	4,252		Nm^3/h	Oxygen
Moisture	Nm^3/h		246,863	246,863	256,419	256,419	256,419	256,811	239,126	247,646	247,646		0	17,730	150	Nm^3/h	Moisture
Sulfur di oxide	Nm^3/h		79	79	82	82	82	81	75	78	78		0	6		Nm^3/h	Sulfur di oxide
Sulfur tri oxide	Nm^3/h		0	0	0	0	0	1	1	1	1		0	0			
Nitrogen oxide	Nm^3/h		0	0	0	0	0	0	0	0	0		0	0			
Nitrogen dioxide	Nm^3/h		307	307	306	306	306	45	41	46	46		0	3		Nm^3/h	Nitrogen di oxide
Argon	Nm^3/h		0	0	2	2	49	49	45	46	46		46	3			
Ammonia	Nm^3/h		0	0	0	0	263	3	3	3	3		0	0			
Total	Nm^3/h		1,180,582	1,180,582	1,226,374	1,226,374	1,231,634	1,231,766	1,146,942	1,186,234	1,186,234		4,997	84,927	214	Nm^3/h	Total
Mass Flow																	Mass Flow
Nitrogen	kg/h	1,873,285	936,643	936,643	973,016	973,016	977,894	978,385	911,010	942,010	942,010		4,878	67,442	80	kg/h	Nitrogen
Carbon di oxide	kg/h	492,954	246,477	246,477	255,979	255,979	255,982	255,982	238,354	246,480	246,480		3	17,647		kg/h	Carbon di oxide
Oxygen	kg/h	167,370	83,685	83,685	86,967	86,967	88,461	88,275	82,196	84,807	84,807		1,495	6,072		kg/h	Oxygen
Moisture	kg/h	396,920	198,460	198,460	206,142	206,142	206,142	206,457	192,240	199,090	199,090		0	14,254	120	kg/h	Moisture
Sulfur di oxide	kg/h	450	225	225	234	234	234	231	215	223	223		0	16		kg/h	Sulfur di oxide
Sulfur tri oxide	kg/h		0	0	0	0	0	3	3	3	3		0	0			
Nitrogen oxide	kg/h		0	0	0	0	0	0	0	0	0		0	0			
Nitrogen di oxide	kg/h	1,261	631	631	628	628	628	91	85	95	95		0	7		kg/h	Nitrogen di oxide
Argon	kg/h		0	0	4	4	87	87	81	83	83		83	6			
Ammonia	kg/h		0	0	0	0	201	2	2	2	2	201	0	0			
Particulate	kg/h	70	35	35	36	36	36	36	34	35	35		0	3			
Total	kg/h	2,932,310	1,466,155	1,466,155	1,523,007	1,523,007	1,529,666	1,529,550	1,424,220	1,472,827	1,472,827	201	6,459	105,446	201	kg/h	Total
Nitrogen	lb/h		2,063,089	2,063,089	2,143,208	2,143,208	2,153,953	2,155,033	2,006,630	2,074,912	2,074,912	0	10,745	148,552	177	lb/h	Nitrogen
Carbon di oxide	lb/h		542,901	542,901	563,831	563,831	563,837	563,837	525,009	542,907	542,907	0	6	38,869	0	lb/h	Carbon di oxide
Oxygen	lb/h		184,328	184,328	191,556	191,556	194,849	194,438	181,048	186,800	186,800	0	3,293	13,374	0	lb/h	Oxygen
Moisture	lb/h		437,137	437,137	454,057	454,057	454,057	454,752	423,436	438,523	438,523	0	0	31,396	265	lb/h	Moisture
Sulfur di oxide	lb/h		496	496	514	514	514	510	474	491	491	0	0	35	0	lb/h	Sulfur di oxide
Sulfur tri oxide	lb/h		0	0	0	0	0	6	6	6	6		0	0			
Nitrogen oxide	lb/h		0	0	0	0	0	0	0	0	0		0	0			
Nitrogen di oxide	lb/h		1,389	1,389	1,384	1,384	1,384	202	188	208	208	0	0	15	0	lb/h	Nitrogen di oxide
Argon	lb/h		0	0	9	9	191	191	178	182	182		182	13			
Ammonia	lb/h		0	0	0	0	442	5	5	5	5		0	0			
Particulate	lb/h		77	77	80	80	80	80		77	77		0	6			
Total	lb/h		3,229,416	3,229,416	3,354,640	3,354,640	3,369,309	3,369,054	3,136,975	3,244,113	3,244,113	0	14,227	232,260	442	lb/h	Total
Composition																	Composition
Nitrogen	Mass-parts		0.639	0.639	0.639	0.639	0.639	0.640	0.640	0.640	0.640		0.755	0.640		Mass-parts	Nitrogen
Carbon di oxide	Mass-parts		0.168	0.168	0.168	0.168	0.167	0.167	0.167	0.167	0.167		0.000	0.167		Mass-parts	Carbon di oxide
Oxygen	Mass-parts		0.057	0.057	0.057	0.057	0.058	0.058	0.058	0.058	0.058		0.231	0.058		Mass-parts	Oxygen
Moisture	Mass-parts		0.135	0.135	0.135	0.135	0.135	0.135	0.135	0.135	0.135		0.000	0.135		Mass-parts	Moisture
Sulfur di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000		Mass-parts	Sulfur di oxide
Sulfur tri oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000			
Nitrogen oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000			
Nitrogen di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000		Mass-parts	Nitrogen di oxide
Argon	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.013	0.000			
Ammonia	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000			
Particulate	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000			
Total	Mass-parts		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	0.000	0.987	1.000	0.000	Mass-parts	Total

MRY 2		Input Data	3	4	5	6	7	8	9	10	11	14	15	17	14 Reacted		
		FGD Outlet	FGD Outlet	GGH inlet	GGH outlet	Steam HE out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Ammonia	Dilution Air	Purge+Scavange			
Density	kg/Nm^3		1.242	1.242	1.242	1.242	1.242	1.242	1.242	1.242	1.242						
Cp	kJ/kgK		1.118792829	1.1197279	1.1779222	1.186904869	1.1863618	1.186361804	1.186361804	1.12492337	1.12492337					kJ/kgK	Cp
Heat Content	MW		28.098	29.895	133.689	148.655	148.397	148.397	138.167	39.834	39.834					MW	Heat Content
	MMBTU/hr		95.899	102.032	456.280	507.360	506.478	506.478	471.565	135.953	135.953						
NO_2	lbs/hour		1388.7665	1388.7665	1384.0485	1384.0485	1384.0485	201.5056	187.6292	208.3150	208.3150			14.9		lbs/hour	NO_2
NO_2	kg/h		630.5000	630.5000	628.3580	628.3580	628.3580	91.4835	85.1837	94.5750	94.5750			6.8		kg/h	NO_2
NO_2	Nm^3 / hour		307.2	307.2	306.1	306.1	306.1	44.6	41.5	46.1	46.1			3.3			
NO + NO_2 @ actual O_2	PPM		260.2	260.2	249.6	249.6	248.5	36.2	36.2	38.8	38.8			38.8			
NO + NO_2 @ 3 % O_2	PPM		292.0	292.0	280.2	280.2	280.1	40.8	40.8	43.7	43.7						

Eta NOx		0.850	0.8500	NO2 Balance Check			
Eta NOx reactor			0.8544	kg/h	lbs/hr		
				-0.9	-2		
SO2/SO3 Conversion Rate	%	1.00%					
				Diff. heat hot side		Diff. heat cold side	0.663477551
Ammonia slip	PPM	2		MW		MW	
				14.966		11.736	
Temperature Diff. Hot Side	F	50					

-2

MRY 2 Tail End SCR Process Flow Diagram



From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Saturday, February 07, 2009 5:25 PM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: Hypothetical Case_Tail End SCR

Bob,
Attached are the latest Mass Balances and PFDs for the Steam and Nat Gas reheat cases. We revised the Steam case from the version previously sent.

We will be working on the Low Dust case as soon as we thoroughly review the revised spreadsheet you sent. We were both out of town last week.

Let us know if you have any questions.
Thanks, Bob

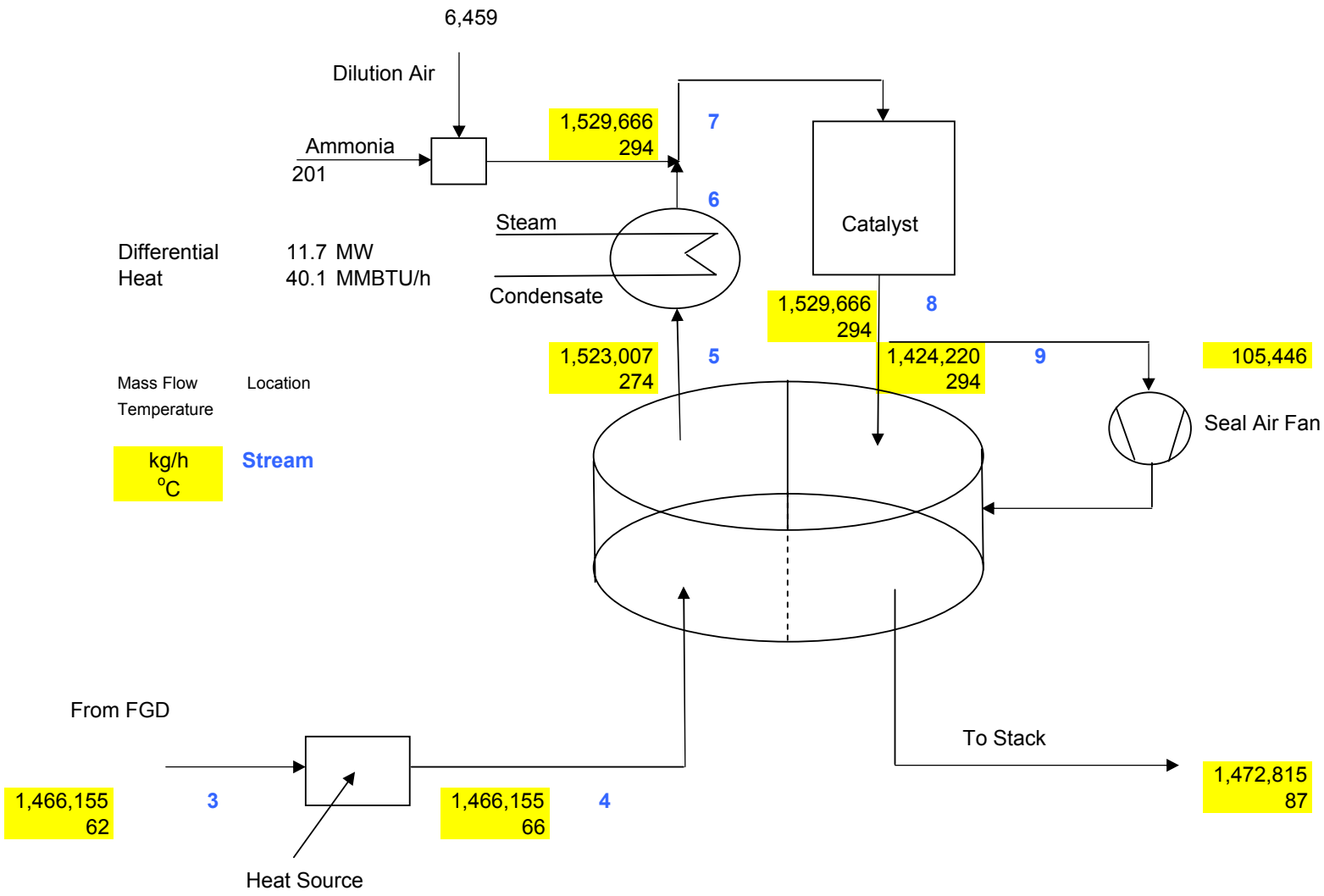
Robert E. Johnson

Fuel Tech, Inc

(913) 897 0727

<<6Feb09_PFD_natgas_downstream_FGD.pdf>> <<6Feb09_MassBalance_MRY2TailEnd_Rev0.pdf>>
<<6Feb09_MRY2TailEnd_Rev0_natgas_downstrm_FGD.pdf>> <<6Feb09_PFD_MRY2TailEnd_Rev0.pdf>>

MRY 2 Tail End SCR Process Flow Diagram



MRY 2		Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted		
		FGD Outlet	FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	Dilution Air	Purge+Scavange	Burner Flue Gas			
Volumetric flow rate vol.	Nm^3/h		1,180,582	1,180,582	1,226,360	1,243,637	1,248,897	1,249,034	1,164,200	1,186,234	1,186,234	1,240	16,030	263	4,997	84,927	17,270		Nm^3/h	Volumetric flow rate vol.
Volumetric flow rate vol.	scfm		744,304	744,304	773,165	784,057	787,374	787,460	733,976	747,868	747,868	781	10,106	166	3,150	53,543	10,888		scfm	Volumetric flow rate vol.
Volumetric flow rate vol.	acfm		820,913	820,913	1,401,624	1,485,058	1,494,932	1,505,978	1,405,398	929,352	929,352								acfm	Volumetric flow rate vol.
Mass Flow	kg/h		1,466,155	1,466,155	1,523,007	1,544,383	1,551,042	1,551,042	1,445,597	1,494,191	1,494,191	966	20,410	201	6,459	105,446	21,376	201	kg/h	Mass Flow
Mass Flow	lb/hour		3,229,416	3,229,416	3,354,640	3,401,724	3,416,393	3,416,393	3,184,133	3,291,169	3,291,169	2,129	44,956	442	14,227	232,260	47,084	442	lb/hour	Mass Flow
Temperature	Degree F	143	143	150	520	562	562	562	562	196	196								Degree F	Temperature
Temperature	Degree C		62	66	271	294	294	294	294	91	91								Degree C	Temperature
Pressure	iwg		14.5	13.5	10	9	8	5	4.5	0	0									Pressure
Composition																				Composition
Nitrogen	Vol-parts		0.6346	0.6346	0.6346	0.6365	0.6370	0.6372	0.6372	0.6352	0.6352		0.7900		0.7809		0.7705	0.2999	Vol-parts	Nitrogen
Carbon di oxide	Vol-parts		0.1063	0.1063	0.1063	0.1058	0.1053	0.1053	0.1053	0.1058	0.1058				0.0003		0.0703		Vol-parts	Carbon di oxide
Oxygen	Vol-parts		0.0496	0.0496	0.0497	0.0492	0.0498	0.0497	0.0497	0.0501	0.0501		0.2100		0.2095		0.0147		Vol-parts	Oxygen
Moisture	Vol-parts		0.2091	0.2091	0.2091	0.2082	0.2073	0.2076	0.2076	0.2088	0.2088						0.1445	0.7001	Vol-parts	Moisture
Sulfur di oxide	Vol-parts		0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001						0.0000		Vol-parts	Sulfur di oxide
Sulfur tri oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000			
Nitrogen oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000			
Nitrogen di oxide	Vol-parts		0.0003	0.0003	0.0002	0.0002	0.0002	0.0000	0.0000	0.0000	0.0000						0.0000		Vol-parts	Nitrogen di oxide
Argon	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				0.0093		0.0000			
Ammonia	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000						0.0000			
Total			1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000		1.0000		1.0000		1.0000	1.0000		Total
Volumetric Flow			0																	Volumetric Flow
Nitrogen	Nm^3/h		749,220	749,220	778,316	791,614	795,516	795,913	741,855	753,514	753,514		12,664		3,902	53,947	13,306	64	Nm^3/h	Nitrogen
Carbon di oxide	Nm^3/h		125,507	125,507	130,345	131,559	131,561	131,561	122,625	125,508	125,508				1	8,986	1,214		Nm^3/h	Carbon di oxide
Oxygen	Nm^3/h		58,606	58,606	60,904	61,158	62,205	62,072	57,856	59,391	59,391		3,366		1,047	4,252	254		Nm^3/h	Oxygen
Moisture	Nm^3/h		246,863	246,863	256,419	258,913	258,913	259,309	241,697	247,646	247,646				0	17,730	2,496	150	Nm^3/h	Moisture
Sulfur di oxide	Nm^3/h		79	79	82	82	82	81	75	78	78				0	6	0		Nm^3/h	Sulfur di oxide
Sulfur tri oxide	Nm^3/h		0	0	0	0	0	1	1	1	1				0	0	0			
Nitrogen oxide	Nm^3/h		0	0	0	0	0	0	0	0	0				0	0	0			
Nitrogen dioxide	Nm^3/h		307	307	306	310	310	45	42	47	46				0	3	0		Nm^3/h	Nitrogen di oxide
Argon	Nm^3/h		0	0	2	2	49	49	45	46	46				46	3	0			
Ammonia	Nm^3/h		0	0	0	0	263	3	3	3	3				0	0	0			
Total	Nm^3/h		1,180,582	1,180,582	1,226,374	1,243,637	1,248,897	1,249,034	1,164,200	1,186,235	1,186,234		16,030		4,997	84,927	17,270	214	Nm^3/h	Total
Mass Flow																				Mass Flow
Nitrogen	kg/h	1,873,285	936,643	936,643	973,016	989,641	994,519	995,015	927,435	942,010	942,010		15,832		4,878	67,442	16,625	80	kg/h	Nitrogen
Carbon di oxide	kg/h	492,954	246,477	246,477	255,979	258,363	258,366	258,366	240,818	246,480	246,480				3	17,647	2,384		kg/h	Carbon di oxide
Oxygen	kg/h	167,370	83,685	83,685	86,967	87,329	88,824	88,635	82,615	84,807	84,807		4,807		1,495	6,072	363		kg/h	Oxygen
Moisture	kg/h	396,920	198,460	198,460	206,142	208,147	208,147	208,466	194,307	199,090	199,090				0	14,254	2,005	120	kg/h	Moisture
Sulfur di oxide	kg/h	450	225	225	234	234	234	231	216	223	223				0	16			kg/h	Sulfur di oxide
Sulfur tri oxide	kg/h		0	0	0	0	0	3	3	3	3				0	0				
Nitrogen oxide	kg/h		0	0	0	0	0	0	0	0	0				0	0				
Nitrogen di oxide	kg/h	1,261	631	631	628	636	636	93	86	96	95				0	7	7		kg/h	Nitrogen di oxide
Argon	kg/h		0	0	4	4	87	87	81	83	83				83	6				
Ammonia	kg/h		0	0	0	0	201	2	2	2	2			201	0	0				
Particulate	kg/h	70	35	35	36	36	36	36	34	35	35				0	3				
Total	kg/h	2,932,310	1,466,155	1,466,155	1,523,007	1,544,390	1,551,050	1,550,935	1,445,597	1,472,828	1,472,827		20,639	201	6,459	105,446	21,383	201	kg/h	Total
Nitrogen	lb/h		2,063,089	2,063,089	2,143,208	2,179,826	2,190,571	2,191,664	2,042,808	2,074,912	2,074,912		34,872	0	10,745	148,552	36,619	177	lb/h	Nitrogen
Carbon di oxide	lb/h		542,901	542,901	563,831	569,082	569,088	569,088	530,436	542,907	542,907			0	6	38,869	5,251	0	lb/h	Carbon di oxide
Oxygen	lb/h		184,328	184,328	191,556	192,355	195,648	195,232	181,972	186,800	186,800		10,588	0	3,293	13,374	799	0	lb/h	Oxygen
Moisture	lb/h		437,137	437,137	454,057	458,473	458,473	459,175	427,989	438,523	438,523			0	0	31,396	4,416	265	lb/h	Moisture
Sulfur di oxide	lb/h		496	496	514	514	514	510	475	491	491			0	0	35		0	lb/h	Sulfur di oxide
Sulfur tri oxide	lb/h		0	0	0	0	0	6	6	6	6				0	0				
Nitrogen oxide	lb/h		0	0	0	0	0	0	0	0	0				0	0				
Nitrogen di oxide	lb/h		1,389	1,389	1,384	1,400	1,400	204	190	211	208			0	0	15	16	0	lb/h	Nitrogen di oxide
Argon	lb/h		0	0	9	9	191	191	178	182	182				182	13				
Ammonia	lb/h		0	0	0	0	442	5	5	5	5				0	0				
Particulate	lb/h		77	77	80	80	80	80		77	77				0	6				
Total	lb/h		3,229,416	3,229,416	3,354,640	3,401,740	3,416,409	3,416,156	3,184,059	3,244,115	3,244,113		45,460	0	14,227	232,260	47,100	442	lb/h	Total
Composition																				Composition
Nitrogen	Mass-parts		0.639	0.639	0.639	0.641	0.641	0.642	0.642	0.640	0.640		0.767		0.755	0.640	0.777		Mass-parts	Nitrogen
Carbon di oxide	Mass-parts		0.168	0.168	0.168	0.167	0.167	0.167	0.167	0.167	0.167		0.000		0.000	0.167	0.111		Mass-parts	Carbon di oxide
Oxygen	Mass-parts		0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.058	0.058		0.233		0.231	0.058	0.017		Mass-parts	Oxygen
Moisture	Mass-parts		0.135	0.135	0.135	0.135	0.134	0.134	0.134	0.135	0.135		0.000		0.000	0.135	0.094		Mass-parts	Moisture
Sulfur di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000		Mass-parts	Sulfur di oxide
Sulfur tri oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000			
Nitrogen oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000			
Nitrogen di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000		Mass-parts	Nitrogen di oxide
Argon	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.013	0.000	0.000			
Ammonia	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000			
Particulate	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000			
Total	Mass-parts		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000		1.000	0.000	0.987	1.000	1.000	0.000	Mass-parts	Total
Density	kg/Nm^3		1.242	1.242	1.242	1.242	1.242	1.242	1.242	1.242	1.242									
Cp	kJ/kgK		1.118792829	1.1197279	1.1788636	1.186311771	1.18631177	1.186311771	1.186311771	1.126080331	1.126080331								kJ/kgK	Cp
Heat Content	MW		28.098	29.895	135.259	149.740	150.386	150.386	140.162	42.580	42.580	14.009							MW	Heat Content
	MMBTU/hr		95.899	102.032	461.638	511.062	513.266	513.266	478.372	145.324	145.324	47.813								
NO_x	lbs/hour		1388.7665	1388.7665	1384.0485	1399.8458	1399.8458	203.8055	189.9632	210.6149	208.3150					14.9			lbs/hour	NO_x

MRY 2		Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted		
		FGD Outlet	FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	Dilution Air	Purge+Scavange	Burner Flue Gas			
NO_2	kg/h		630.5000	630.5000	628.3580	635.5300	635.5300	92.5277	86.2433	95.6192	94.5750					6.8			kg/h	NO_2
NO_2	Nm^3 / hour		307.2	307.2	306.1	309.6	309.6	45.1	42.0	46.6	46.1					3.3				
NO + NO_2 @ actual O_2	PPM		260.2	260.2	249.6	249.0	247.9	36.1	36.1	39.3	38.8					38.8				
NO + NO_2 @ 3 % O_2	PPM		292.0	292.0	280.2	278.6	278.6	40.5	40.5	44.2	43.7									

					NO2 Balance Check			
Eta NOx		0.850	0.8500		kg/h	lbs/hr		
Eta NOx reactor			0.8544			0.1	0	
SO2/SO3 Conversion Rate	%	1.00%						
					Diff. heat hot side	Diff. heat cold side	0.663477551	
Ammonia slip	PPM	2			MW	MW		
					14.481	14.481		
Temperature Diff. Hot Side	F	50						

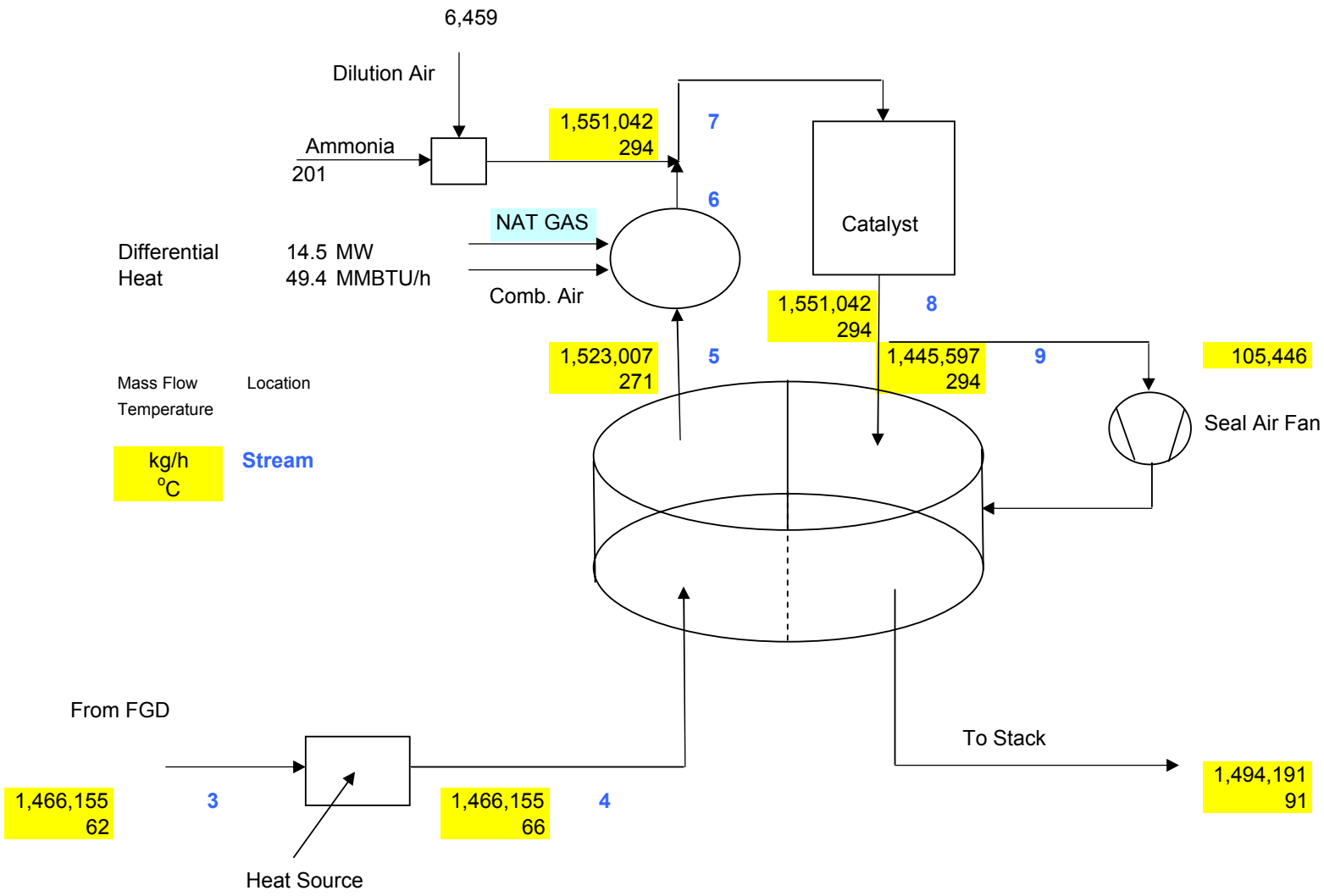
MRY 2		Input Data	3	4	5	6	7	8	9	10	11	14	15	17	14 Reacted		
		FGD Outlet	FGD Outlet	GGH inlet	GGH outlet	Steam HE out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Ammonia	Dilution Air	Purge+Scavange			
Volumetric flow rate vol.	Nm^3/h		1,180,582	1,180,582	1,226,360	1,226,360	1,231,634	1,231,766	1,146,942	1,186,234	1,186,234	263	4,997	84,927		Nm^3/h	Volumetric flow rate vol.
Volumetric flow rate vol.	scfm		744,304	744,304	773,165	773,165	776,490	776,573	723,096	747,868	747,868	166	3,150	53,543		scfm	Volumetric flow rate vol.
Volumetric flow rate vol.	acfm		820,913	820,913	1,409,601	1,469,126	1,474,667	1,485,560	1,384,940	917,742	917,742					acfm	Volumetric flow rate vol.
Mass Flow	kg/h		1,466,155	1,466,155	1,523,007	1,523,007	1,529,666	1,529,666	1,424,220	1,472,815	1,472,815	201	6,459	105,446	201	kg/h	Mass Flow
Mass Flow	lb/hour		3,229,416	3,229,416	3,354,640	3,354,640	3,369,309	3,369,309	3,137,049	3,244,085	3,244,085	442	14,227	232,260	442	lb/hour	Mass Flow
Temperature	Degree F	143	143	150	526	565	562	562	562	188	188					Degree F	Temperature
Temperature	Degree C		62	66	274	296	294	294	294	87	87					Degree C	Temperature
Pressure	iwg		14.5	13.5	10	9	8	5	4.5	0	0						Pressure
Composition																	Composition
Nitrogen	Vol-parts		0.6346	0.6346	0.6346	0.6346	0.6351	0.6354	0.6354	0.6352	0.6352		0.7809		0.2999	Vol-parts	Nitrogen
Carbon di oxide	Vol-parts		0.1063	0.1063	0.1063	0.1063	0.1058	0.1058	0.1058	0.1058	0.1058		0.0003			Vol-parts	Carbon di oxide
Oxygen	Vol-parts		0.0496	0.0496	0.0497	0.0497	0.0503	0.0502	0.0502	0.0501	0.0501		0.2095			Vol-parts	Oxygen
Moisture	Vol-parts		0.2091	0.2091	0.2091	0.2091	0.2082	0.2085	0.2085	0.2088	0.2088				0.7001	Vol-parts	Moisture
Sulfur di oxide	Vol-parts		0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001					Vol-parts	Sulfur di oxide
Sulfur tri oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						
Nitrogen oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						
Nitrogen di oxide	Vol-parts		0.0003	0.0003	0.0002	0.0002	0.0002	0.0000	0.0000	0.0000	0.0000					Vol-parts	Nitrogen di oxide
Argon	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0093				
Ammonia	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000						
Total			1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000		1.0000		1.0000		Total
Volumetric Flow			0														Volumetric Flow
Nitrogen	Nm^3/h		749,220	749,220	778,316	778,316	782,218	782,610	728,717	753,514	753,514		3,902	53,947	64	Nm^3/h	Nitrogen
Carbon di oxide	Nm^3/h		125,507	125,507	130,345	130,345	130,347	130,347	121,371	125,508	125,508		1	8,986		Nm^3/h	Carbon di oxide
Oxygen	Nm^3/h		58,606	58,606	60,904	60,904	61,951	61,820	57,563	59,391	59,391		1,047	4,252		Nm^3/h	Oxygen
Moisture	Nm^3/h		246,863	246,863	256,419	256,419	256,419	256,811	239,126	247,646	247,646		0	17,730	150	Nm^3/h	Moisture
Sulfur di oxide	Nm^3/h		79	79	82	82	82	81	75	78	78		0	6		Nm^3/h	Sulfur di oxide
Sulfur tri oxide	Nm^3/h		0	0	0	0	0	1	1	1	1		0	0			
Nitrogen oxide	Nm^3/h		0	0	0	0	0	0	0	0	0		0	0			
Nitrogen dioxide	Nm^3/h		307	307	306	306	306	45	41	46	46		0	3		Nm^3/h	Nitrogen di oxide
Argon	Nm^3/h		0	0	2	2	49	49	45	46	46		46	3			
Ammonia	Nm^3/h		0	0	0	0	263	3	3	3	3		0	0			
Total	Nm^3/h		1,180,582	1,180,582	1,226,374	1,226,374	1,231,634	1,231,766	1,146,942	1,186,234	1,186,234		4,997	84,927	214	Nm^3/h	Total
Mass Flow																	Mass Flow
Nitrogen	kg/h	1,873,285	936,643	936,643	973,016	973,016	977,894	978,385	911,010	942,010	942,010		4,878	67,442	80	kg/h	Nitrogen
Carbon di oxide	kg/h	492,954	246,477	246,477	255,979	255,979	255,982	255,982	238,354	246,480	246,480		3	17,647		kg/h	Carbon di oxide
Oxygen	kg/h	167,370	83,685	83,685	86,967	86,967	88,461	88,275	82,196	84,807	84,807		1,495	6,072		kg/h	Oxygen
Moisture	kg/h	396,920	198,460	198,460	206,142	206,142	206,142	206,457	192,240	199,090	199,090		0	14,254	120	kg/h	Moisture
Sulfur di oxide	kg/h	450	225	225	234	234	234	231	215	223	223		0	16		kg/h	Sulfur di oxide
Sulfur tri oxide	kg/h		0	0	0	0	0	3	3	3	3		0	0			
Nitrogen oxide	kg/h		0	0	0	0	0	0	0	0	0		0	0			
Nitrogen di oxide	kg/h	1,261	631	631	628	628	628	91	85	95	95		0	7		kg/h	Nitrogen di oxide
Argon	kg/h		0	0	4	4	87	87	81	83	83		83	6			
Ammonia	kg/h		0	0	0	0	201	2	2	2	2	201	0	0			
Particulate	kg/h	70	35	35	36	36	36	36	34	35	35		0	3			
Total	kg/h	2,932,310	1,466,155	1,466,155	1,523,007	1,523,007	1,529,666	1,529,550	1,424,220	1,472,827	1,472,827	201	6,459	105,446	201	kg/h	Total
Nitrogen	lb/h		2,063,089	2,063,089	2,143,208	2,143,208	2,153,953	2,155,033	2,006,630	2,074,912	2,074,912	0	10,745	148,552	177	lb/h	Nitrogen
Carbon di oxide	lb/h		542,901	542,901	563,831	563,831	563,837	563,837	525,009	542,907	542,907	0	6	38,869	0	lb/h	Carbon di oxide
Oxygen	lb/h		184,328	184,328	191,556	191,556	194,849	194,438	181,048	186,800	186,800	0	3,293	13,374	0	lb/h	Oxygen
Moisture	lb/h		437,137	437,137	454,057	454,057	454,057	454,752	423,436	438,523	438,523	0	0	31,396	265	lb/h	Moisture
Sulfur di oxide	lb/h		496	496	514	514	514	510	474	491	491	0	0	35	0	lb/h	Sulfur di oxide
Sulfur tri oxide	lb/h		0	0	0	0	0	6	6	6	6		0	0			
Nitrogen oxide	lb/h		0	0	0	0	0	0	0	0	0		0	0			
Nitrogen di oxide	lb/h		1,389	1,389	1,384	1,384	1,384	202	188	208	208	0	0	15	0	lb/h	Nitrogen di oxide
Argon	lb/h		0	0	9	9	191	191	178	182	182		182	13			
Ammonia	lb/h		0	0	0	0	442	5	5	5	5		0	0			
Particulate	lb/h		77	77	80	80	80	80		77	77		0	6			
Total	lb/h		3,229,416	3,229,416	3,354,640	3,354,640	3,369,309	3,369,054	3,136,975	3,244,113	3,244,113	0	14,227	232,260	442	lb/h	Total
Composition																	Composition
Nitrogen	Mass-parts		0.639	0.639	0.639	0.639	0.639	0.640	0.640	0.640	0.640		0.755	0.640		Mass-parts	Nitrogen
Carbon di oxide	Mass-parts		0.168	0.168	0.168	0.168	0.167	0.167	0.167	0.167	0.167		0.000	0.167		Mass-parts	Carbon di oxide
Oxygen	Mass-parts		0.057	0.057	0.057	0.057	0.058	0.058	0.058	0.058	0.058		0.231	0.058		Mass-parts	Oxygen
Moisture	Mass-parts		0.135	0.135	0.135	0.135	0.135	0.135	0.135	0.135	0.135		0.000	0.135		Mass-parts	Moisture
Sulfur di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000		Mass-parts	Sulfur di oxide
Sulfur tri oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000			
Nitrogen oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000			
Nitrogen di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000		Mass-parts	Nitrogen di oxide
Argon	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.013	0.000			
Ammonia	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000			
Particulate	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000			
Total	Mass-parts		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	0.000	0.987	1.000	0.000	Mass-parts	Total

MRY 2		Input Data	3	4	5	6	7	8	9	10	11	14	15	17	14 Reacted		
		FGD Outlet	FGD Outlet	GGH inlet	GGH outlet	Steam HE out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Ammonia	Dilution Air	Purge+Scavange			
Density	kg/Nm^3		1.242	1.242	1.242	1.242	1.242	1.242	1.242	1.242	1.242						
Cp	kJ/kgK		1.118792829	1.1197279	1.1798596	1.186904869	1.1863618	1.186361804	1.186361804	1.12492337	1.12492337					kJ/kgK	Cp
Heat Content	MW		28.098	29.895	136.919	148.655	148.397	148.397	138.167	39.834	39.834					MW	Heat Content
	MMBTU/hr		95.899	102.032	467.305	507.360	506.478	506.478	471.565	135.953	135.953						
NO_2	lbs/hour		1388.7665	1388.7665	1384.0485	1384.0485	1384.0485	201.5056	187.6292	208.3150	208.3150			14.9		lbs/hour	NO_2
NO_2	kg/h		630.5000	630.5000	628.3580	628.3580	628.3580	91.4835	85.1837	94.5750	94.5750			6.8		kg/h	NO_2
NO_2	Nm^3 / hour		307.2	307.2	306.1	306.1	306.1	44.6	41.5	46.1	46.1			3.3			
NO + NO_2 @ actual O_2	PPM		260.2	260.2	249.6	249.6	248.5	36.2	36.2	38.8	38.8			38.8			
NO + NO_2 @ 3 % O_2	PPM		292.0	292.0	280.2	280.2	280.1	40.8	40.8	43.7	43.7						

Eta NOx		0.850	0.8500	NO2 Balance Check			
				kg/h	lbs/hr		
Eta NOx reactor			0.8544	-0.9	-2		
SO2/SO3 Conversion Rate	%	1.00%					
				Diff. heat hot side		Diff. heat cold side	0.663477551
Ammonia slip	PPM	2		MW		MW	
				11.736		11.736	
Temperature Diff. Hot Side	F	50					

-2

MRY 2 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



Blakley, Robert

From: Blakley, Robert
Sent: Monday, February 09, 2009 5:30 PM
To: 'Robert Johnson'
Cc: 'Volker Rummenhohl'; Weilert, Carl; Voss, Steve; Bryant, Ronald; Blackwood, Dave
Subject: RE: Hypothetical Case_Tail End SCR

Bob & Volker –

We will review your recent mass balances for Unit 2.

Do you expect there to be a FGD GGH and booster fan downstream of the existing U2 wet lime FGD absorbers, upstream of the TESCR GGH? We expect the existing ID fans, or their replacements, will control boiler draft, so the TESCR will need a booster fan to overcome the GGH, reactor, and GGH treated side pressure drops.

As mentioned previously, I believe the typical FGD outlet pressure on U2's existing scrubbers is around 3-3.5 in. w.c., with 330-340 degF inlet gas entering the towers, at full load conditions (approx. 4800 mmBtu/hr boiler heat input). The absorber vessels are not rated to operate beyond around 4 in. w.c., which we are attempting to confirm.

The 5,158 mmBtu/hr heat input rate in the design basis is for short term, maximum output operation, for the plant's reserve capacity rating.

I also need to know the equation for converting ACFM or SCFM to normal cubic meters (Nm3). We're trying to calculate particulate and sodium loading expected to enter the LDSCR and TESCR reactors, in terms of milligrams or micrograms per Nm3.

Bob Blakley

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Saturday, February 07, 2009 5:25 PM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: Hypothetical Case_Tail End SCR

Bob,
Attached are the latest Mass Balances and PFDs for the Steam and Nat Gas reheat cases. We revised the Steam case from the version previously sent.

We will be working on the Low Dust case as soon as we thoroughly review the revised spreadsheet you sent. We were both out of town last week.

Let us know if you have any questions.
Thanks, Bob

Robert E. Johnson
Fuel Tech, Inc
(913) 897 0727
<<6Feb09_PFD_natgas_downstream_FGD.pdf>> <<6Feb09_MassBalance_MRY2TailEnd_Rev0.pdf>>
<<6Feb09_MRY2TailEnd_Rev0_natgas_downstrm_FGD.pdf>> <<6Feb09_PFD_MRY2TailEnd_Rev0.pdf>>

Blakley, Robert

From: Blakley, Robert
Sent: Tuesday, March 03, 2009 12:26 PM
To: 'Robert Johnson'
Cc: 'Volker Rummenhohl'; Bryant, Ronald; Blackwood, Dave
Subject: RE: Hypothetical Case_Tail End SCR

Bob & Volker -

One of the decisions from the SCR cost estimate study kickoff meeting with Minnkota last Thursday, February 26 was to assume natural gas firing for supplemental flue gas heating for both LD and TESCR cases for MRYS Unit 1 and Unit 2. Minnkota has established this as their reheat source they prefer.

In addition, Minnkota directed BMcD to assume urea for the ammonia source. Our understanding is that this may slightly affect the SCR mass balances when the urea is converted to ammonia before being injected into the flue gas stream because of the CO2 and water that will be driven off. The urea solution will be stored at 50% concentration on-site prior to feeding.

Please consider these decisions so that you can revise the preliminary mass balances for the LD and TESCR cases for MRYS Unit 1 and Unit 2 and provide estimated reactor sizing.

We would like to get the revised mass balances within 1 week and the preliminary reactor sizing by mid-March if possible. I don't know what the latter entails, so advise an alternate time table if this is more complicated than I realize.

Please advise if question arise.

Thanks,

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Saturday, February 07, 2009 5:25 PM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: Hypothetical Case_Tail End SCR

Bob,
Attached are the latest Mass Balances and PFDs for the Steam and Nat Gas reheat cases. We revised the Steam case from the version previously sent.

We will be working on the Low Dust case as soon as we thoroughly review the revised spreadsheet you sent. We were both out of town last week.

Let us know if you have any questions.
Thanks, Bob

Robert E. Johnson
Fuel Tech, Inc
(913) 897 0727
<<6Feb09_PFD_natgas_downstream_FGD.pdf>> <<6Feb09_MassBalance_MRY2TailEnd_Rev0.pdf>> <<6Feb09_MRY2TailEnd_Rev0_natgas_downstrm_FGD.pdf>> <<6Feb09_PFD_MRY2TailEnd_Rev0.pdf>>

Blakley, Robert

From: Blakley, Robert
Sent: Friday, March 06, 2009 12:10 PM
To: 'Robert Johnson'
Cc: 'Volker Rummenhohl'; Bryant, Ronald; Blackwood, Dave; Voss, Steve
Subject: RE: Hypothetical Case_Tail End SCR

Bob –

I don't envision Minnkota having ammonia storage tanks in addition to the concentrated urea storage tanks, if the urea-to-ammonia conversion isn't "on demand".
I assume either a FT "Ultra" system or the hydrolyzer approach would satisfy that requirement.

My guess is since Minnkota has chosen natural gas-fired final reheat for the flue gas ahead of the SCR reactor for either LD or TE SCR cases as the energy source, rather than steam, they would probably go with the Fuel Tech version that uses fuel to decompose the urea rather than a hydrolyzer that uses steam.

I suppose it may depend on how much heat is required and what steam conditions are involved for the hydrolyzer. I am not familiar with that process but I'm sure we could check into that from another SCR project is needed.

Bob Blakley

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Friday, March 06, 2009 11:59 AM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: RE: Hypothetical Case_Tail End SCR

Bob,
Thanks. We will revise the mass balances, but it will probably take until next Friday.
Has Minnkota determined the type of urea system? one requires steam for the hydrolysis and Fuel Tech's requires a combustion fuel. in this case, we would use the natural gas. Our system will affect the mass balance due to additional NOx, and byproducts such as H2O and CO2. We wouldn't account for trace byproducts.

The reactor size is easier, but mid-March is fine as a deadline.

Just to confirm, you need 4 mass balances: LD and TE for both MRYS 1 and 2.

Best Regards,
Bob

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Tuesday, March 03, 2009 12:26 PM
To: Robert Johnson
Cc: Volker Rummenhohl; Bryant, Ronald; Blackwood, Dave
Subject: RE: Hypothetical Case_Tail End SCR

Bob & Volker -

One of the decisions from the SCR cost estimate study kickoff meeting with Minnkota last Thursday, February 26 was to assume

natural gas firing for supplemental flue gas heating for both LD and TESCR cases for MRYS Unit 1 and Unit 2. Minnkota has established this as their reheat source they prefer.

In addition, Minnkota directed BMcD to assume urea for the ammonia source. Our understanding is that this may slightly affect the SCR mass balances when the urea is converted to ammonia before being injected into the flue gas stream because of the CO2 and water that will be driven off. The urea solution will be stored at 50% concentration on-site prior to feeding.

Please consider these decisions so that you can revise the preliminary mass balances for the LD and TESCR cases for MRYS Unit 1 and Unit 2 and provide estimated reactor sizing.

We would like to get the revised mass balances within 1 week and the preliminary reactor sizing by mid-March if possible. I don't know what the latter entails, so advise an alternate time table if this is more complicated than I realize.

Please advise if question arise.

Thanks,

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Saturday, February 07, 2009 5:25 PM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: Hypothetical Case_Tail End SCR

Bob,
Attached are the latest Mass Balances and PFDs for the Steam and Nat Gas reheat cases. We revised the Steam case from the version previously sent.

We will be working on the Low Dust case as soon as we thoroughly review the revised spreadsheet you sent. We were both out of town last week.

Let us know if you have any questions.
Thanks, Bob

Robert E. Johnson
Fuel Tech, Inc
(913) 897 0727
<<6Feb09_PFD_natgas_downstream_FGD.pdf>> <<6Feb09_MassBalance_MRY2TailEnd_Rev0.pdf>>
<<6Feb09_MRY2TailEnd_Rev0_natgas_downstrm_FGD.pdf>> <<6Feb09_PFD_MRY2TailEnd_Rev0.pdf>>

Blakley, Robert

From: Blakley, Robert
Sent: Friday, March 06, 2009 12:25 PM
To: 'Robert Johnson'
Cc: 'Volker Rummenhohl'; Bryant, Ronald; Blackwood, Dave; Voss, Steve
Subject: RE: Hypothetical Case_Tail End SCR

Bob –

I checked on the Seminole SCR project – it appears to use 125 psig saturated steam for the heat source in the urea-to-ammonia conversion process, and electric resistance heat tracing on the urea and ammonia lines.

Oh, and I am confirming that we need information on four cases:
U1 LD and TESCR; and
U2 LD and TESCR.

Bob Blakley

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Friday, March 06, 2009 12:13 PM
To: Blakley, Robert
Cc: Volker Rummenhohl; Bryant, Ronald; Blackwood, Dave; Voss, Steve
Subject: RE: Hypothetical Case_Tail End SCR

Bob,
Thanks.
FYI: the Wahlco hydrolyzer system is being used on the Seminole and Crystal River SCR projects.
Regards, Bob

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Friday, March 06, 2009 12:10 PM
To: Robert Johnson
Cc: Volker Rummenhohl; Bryant, Ronald; Blackwood, Dave; Voss, Steve
Subject: RE: Hypothetical Case_Tail End SCR

Bob –

I don't envision Minnkota having ammonia storage tanks in addition to the concentrated urea storage tanks, if the urea-to-ammonia conversion isn't "on demand".
I assume either a FT "Ultra" system or the hydrolyzer approach would satisfy that requirement.

My guess is since Minnkota has chosen natural gas-fired final reheat for the flue gas ahead of the SCR reactor for either LD or TE SCR cases as the energy source, rather than steam, they would probably go with the Fuel Tech version that uses fuel to decompose the urea rather than a hydrolyzer that uses steam.

I suppose it may depend on how much heat is required and what steam conditions are involved for the hydrolyzer. I am not familiar with that process but I'm sure we could check into that from another SCR project is needed.

Bob Blakley

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Friday, March 06, 2009 11:59 AM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: RE: Hypothetical Case_Tail End SCR

Bob,
Thanks. We will revise the mass balances, but it will probably take until next Friday.
Has Minnkota determined the type of urea system? one requires steam for the hydrolysis and Fuel Tech's requires a combustion fuel. in this case, we would use the natural gas. Our system will affect the mass balance due to additional NOx, and byproducts such as H2O and CO2. We wouldn't account for trace byproducts.

The reactor size is easier, but mid-March is fine as a deadline.

Just to confirm, you need 4 mass balances: LD and TE for both MRYS 1 and 2.

Best Regards,
Bob

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Tuesday, March 03, 2009 12:26 PM
To: Robert Johnson
Cc: Volker Rummenhohl; Bryant, Ronald; Blackwood, Dave
Subject: RE: Hypothetical Case_Tail End SCR

Bob & Volker -

One of the decisions from the SCR cost estimate study kickoff meeting with Minnkota last Thursday, February 26 was to assume natural gas firing for supplemental flue gas heating for both LD and TESCR cases for MRYS Unit 1 and Unit 2. Minnkota has established this as their reheat source they prefer.

In addition, Minnkota directed BMcD to assume urea for the ammonia source. Our understanding is that this may slightly affect the SCR mass balances when the urea is converted to ammonia before being injected into the flue gas stream because of the CO2 and water that will be driven off. The urea solution will be stored at 50% concentration on-site prior to feeding.

Please consider these decisions so that you can revise the preliminary mass balances for the LD and TESCR cases for MRYS Unit 1 and Unit 2 and provide estimated reactor sizing.

We would like to get the revised mass balances within 1 week and the preliminary reactor sizing by mid-March if possible. I don't know what the latter entails, so advise an alternate time table if this is more complicated than I realize.

Please advise if question arise.

Thanks,

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Saturday, February 07, 2009 5:25 PM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: Hypothetical Case_Tail End SCR

Bob,
Attached are the latest Mass Balances and PFDs for the Steam and Nat Gas reheat cases. We revised the Steam case from the version previously sent.

We will be working on the Low Dust case as soon as we thoroughly review the revised spreadsheet you sent. We were both out of town last week.

Let us know if you have any questions.
Thanks, Bob

Robert E. Johnson

Fuel Tech, Inc

(913) 897 0727

<<6Feb09_PFD_natgas_downstream_FGD.pdf>> <<6Feb09_MassBalance_MRY2TailEnd_Rev0.pdf>> <<6Feb09_MRY2TailEnd_Rev0_natgas_downstrm_FGD.pdf>> <<6Feb09_PFD_MRY2TailEnd_Rev0.pdf>>

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Thu 3/12/2009 8:59 AM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: 12Mar09_Preliminary Information

Bob,
Attached are preliminary mass balances and PFDs for the LD and TE hypothetical cases. We have updated these to reflect natural gas firing to control temperatures to the SCR inlet. We have also based these on the use of Fuel Tech's ULTRA system for decomposing urea to ammonia. You will see the various inputs on the PFDs.

Also, we have prepared a table with preliminary reactor sizes. For all 4 cases, we have assumed 2 reactors per unit.
But, for Unit 1, 1 large reactor would also be possible for both cases. This is possible since the mass flow rate of the flue gas is less than 2,000,000 kg/hr.

Please let us know if we can clarify anything.

Best Regards, Bob

Robert E. Johnson

Fuel Tech, Inc

(913) 897 0727

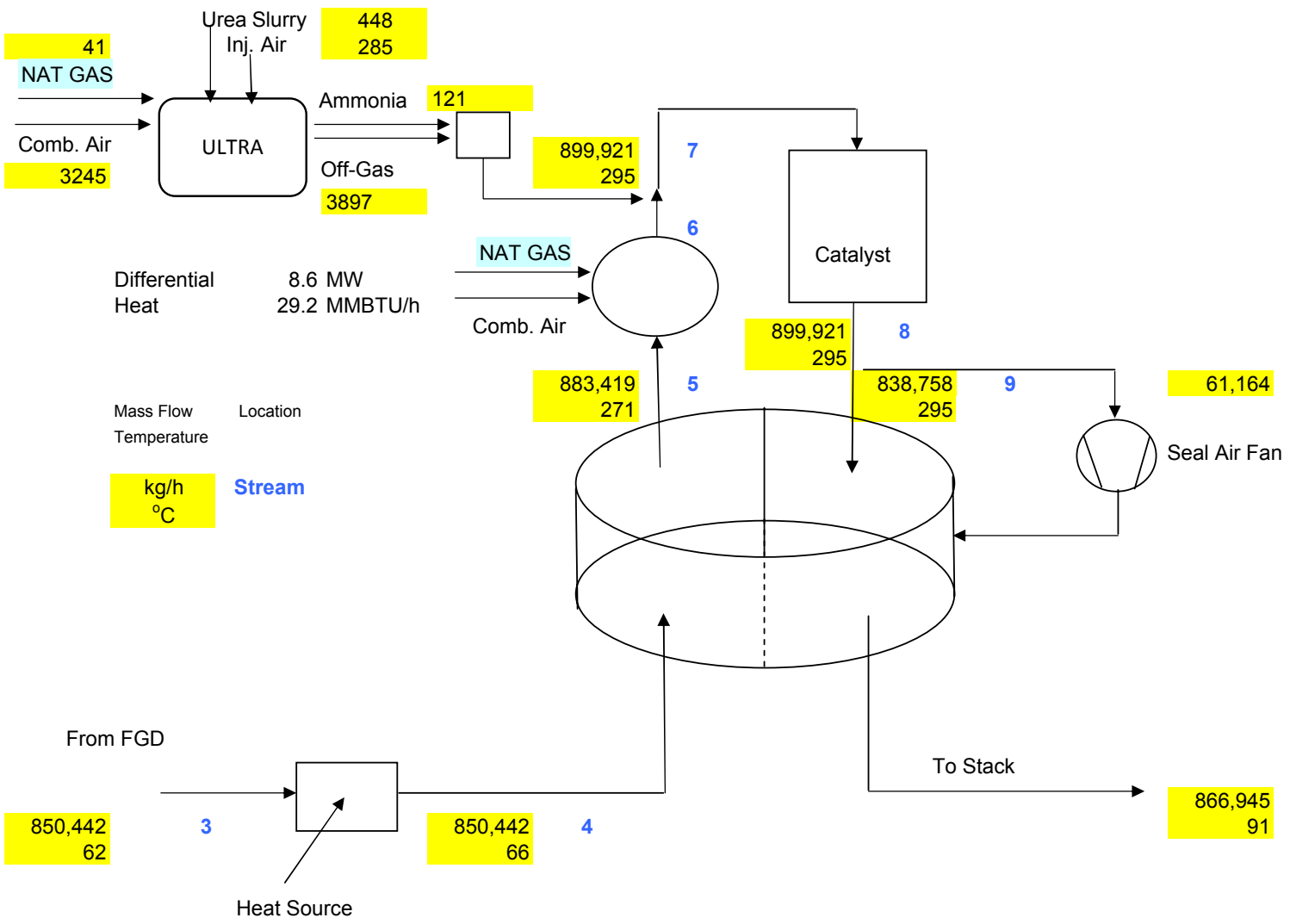
This message contains information that may be privileged, confidential or otherwise protected from disclosure. Unless you are the intended addressee (or authorized recipient for the addressee) you may not use, copy or disclose this message or information contained in this message to anyone. If you received this message in error, please notify the sender by replying to this message and then delete it from your system without copying or disclosing it. Thank you.

<<10Mar09_MRY2LowDust_PFD_Rev0_natgas.pdf>> <<9Mar09_MRY2TailEnd_Mass Balance_Rev0_natgas.pdf>> <<9Mar09_MRY2TailEnd_PFD_Rev0_natgas.pdf>> <<10Mar09_Hypothetical SCR_Reactor Arrangement_Summary.pdf>> <<10Mar09_MRY1LowDust_MassBalance_Rev0_natgas.pdf>> <<10Mar09_MRY1LowDust_PFD_Rev0_natgas.pdf>> <<10Mar09_MRY1TailEnd_MassBalance_Rev0_natgas.pdf>> <<10Mar09_MRY1TailEnd_PFD_Rev0_natgas.pdf>> <<10Mar09_MRY2LowDust_Mass BalanceRev0_natgas.pdf>>

MRY 2		Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21		
		ESP Outlet	ESP Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air		
Volumetric flow rate vol.	Nm^3/h		1,072,689	1,072,689	1,114,284	1,129,869	1,135,150	1,135,286	1,058,149	1,078,363	1,078,363	1,117	14,446	263	5,018	77,189	15,563		86	4,135		293	Nm^3/h	Volumetric flow rate vol.
Volumetric flow rate vol.	scfm		676,283	676,283	702,506	712,332	715,661	715,747	667,116	679,859	679,859	704	9,107	166	3,164	48,664	9,812		54	2,607		185	scfm	Volumetric flow rate vol.
Volumetric flow rate vol.	acfm		978,672	978,672	1,273,531	1,351,693	1,361,282	1,371,355	1,279,731	1,082,007	1,082,007												acfm	Volumetric flow rate vol.
Mass Flow	kg/h		1,374,291	1,374,291	1,427,580	1,446,843	1,453,355	1,453,355	1,354,516	1,400,066	1,400,066	871	18,392	201	6,312	98,839	19,263	201	67	5,324	744	378	kg/h	Mass Flow
Mass Flow	lb/hour		3,027,072	3,027,072	3,144,449	3,186,879	3,201,223	3,201,223	2,983,516	3,083,845	3,083,845	1,918	40,512	442	13,902	217,707	42,430	442	148	11,726	1,638	832	lb/hour	Mass Flow
Temperature	Degree F	331	331	331	520	564	564	564	564	380	380												Degree F	Temperature
Temperature	Degree C		166	166	271	295	295	295	295	193	193												Degree C	Temperature
Pressure	iwg		14.5	13.5	10	9	8	5	4.5	0	0													Pressure
Composition																								Composition
Nitrogen	Vol-parts		0.6879	0.6879	0.6879	0.6890	0.6888	0.6891	0.6891	0.6878	0.6878		0.7900		0.6790		0.7705	0.2999		0.7900		0.7900	Vol-parts	Nitrogen
Carbon di oxide	Vol-parts		0.1156	0.1156	0.1156	0.1150	0.1146	0.1146	0.1146	0.1152	0.1152				0.0467		0.0703						Vol-parts	Carbon di oxide
Oxygen	Vol-parts		0.0525	0.0525	0.0525	0.0520	0.0524	0.0523	0.0523	0.0527	0.0527		0.2100		0.1422		0.0147			0.2100		0.2100	Vol-parts	Oxygen
Moisture	Vol-parts		0.1422	0.1422	0.1423	0.1423	0.1422	0.1425	0.1425	0.1428	0.1428				0.1240		0.1445	0.7001					Vol-parts	Moisture
Sulfur di oxide	Vol-parts		0.0015	0.0015	0.0015	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014						0.0000						Vol-parts	Sulfur di oxide
Sulfur tri oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Sulfur trioxide
Nitrogen oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen oxide
Nitrogen di oxide	Vol-parts		0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen di oxide
Argon	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				0.0081		0.0000						Vol-parts	Argon
Ammonia	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Ammonia
Total			1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000		1.0000		1.0000		1.0000	1.0000		1.0000		1.0000	Vol-parts	Total
Volumetric Flow			0																					Volumetric Flow
Nitrogen	Nm^3/h		737,868	737,868	766,494	778,477	781,884	782,281	729,129	741,666	741,666		11,412		3,407	53,088	11,991	64		3,267		232	Nm^3/h	Nitrogen
Carbon di oxide	Nm^3/h		124,008	124,008	128,799	129,893	130,127	130,127	121,286	124,243	124,243				234	8,893	1,094						Nm^3/h	Carbon di oxide
Oxygen	Nm^3/h		56,358	56,358	58,552	58,781	59,495	59,363	55,329	56,810	56,810		3,034		714	4,066	229			868		62	Nm^3/h	Oxygen
Moisture	Nm^3/h		152,571	152,571	158,521	160,768	161,390	161,787	150,794	153,977	153,977				622	11,022	2,249	150					Nm^3/h	Moisture
Sulfur di oxide	Nm^3/h		1,578	1,578	1,638	1,638	1,638	1,622	1,512	1,562	1,562				0	112	0						Nm^3/h	Sulfur di oxide
Sulfur tri oxide	Nm^3/h		0	0	1	1	1	17	15	16	16				0	1	0						Nm3/h	Sulfur trioxide
Nitrogen oxide	Nm^3/h		0	0	0	0	0	0	0	0	0				0	0	0						Nm3/h	Nitrogen oxide
Nitrogen dioxide	Nm^3/h		307	307	306	309	309	45	42	47	46				0	3	0						Nm^3/h	Nitrogen di oxide
Argon	Nm^3/h		0	0	2	2	42	42	40	40	40				40	3	0						Nm3/h	Argon
Ammonia	Nm^3/h		0	0	0	0	263	3	3	3	3				0	0	0						Nm3/h	Ammonia
Total	Nm^3/h		1,072,689	1,072,689	1,114,312	1,129,869	1,135,150	1,135,286	1,058,149	1,078,363	1,078,363		14,446		5,018	77,189	15,563	214		4,135		293	Nm^3/h	Total
Mass Flow																								Mass Flow
Nitrogen	kg/h	1,844,900	922,450	922,450	958,237	973,218	977,478	977,973	911,525	927,199	927,199		14,267		4,259	66,369	14,982	80		4,084		290	kg/h	Nitrogen
Carbon di oxide	kg/h	487,068	243,534	243,534	252,943	255,091	255,551	255,551	238,188	243,994	243,994				460	17,465	2,148						kg/h	Carbon di oxide
Oxygen	kg/h	160,950	80,475	80,475	83,609	83,935	84,955	84,766	79,007	81,121	81,121		4,332		1,019	5,807	327			1,240		88	kg/h	Oxygen
Moisture	kg/h	245,312	122,656	122,656	127,439	129,246	129,746	130,065	121,227	123,786	123,786				500	8,861	1,807	120			372		kg/h	Moisture
Sulfur di oxide	kg/h	9,020	4,510	4,510	4,682	4,682	4,682	4,636	4,321	4,465	4,465				0	320							kg/h	Sulfur di oxide
Sulfur tri oxide	kg/h		0	0	3	3	3	59	55	56	56				0	4							kg/h	Sulfur trioxide
Nitrogen oxide	kg/h		0	0	0	0	0	0	0	0	0				0	0							kg/h	Nitrogen oxide
Nitrogen di oxide	kg/h	1,261	631	631	628	635	635	92	86	96	95				0	7	6						kg/h	Nitrogen di oxide
Argon	kg/h		0	0	4	4	76	76	71	72	72				72	5							kg/h	Argon
Ammonia	kg/h		0	0	0	0	201	2	2	2	2			201	0	0							kg/h	Ammonia
Particulate	kg/h	70	35	35	36	36	36	36	34	35	35				0	3							kg/h	Particulate
Urea	kg/h																				372		kg/h	Urea
Total	kg/h	2,748,581	1,374,291	1,374,291	1,427,580	1,446,850	1,453,362	1,453,257	1,354,516	1,380,827	1,380,826		18,599	201	6,312	98,839	19,270	201		5,324	744	378	kg/h	Total
Nitrogen	lb/h		2,031,828	2,031,828	2,110,654	2,143,653	2,153,035	2,154,126	2,007,764	2,042,288	2,042,288		31,425	0	9,382	146,186	32,999	177		8,995		638	lb/h	Nitrogen
Carbon di oxide	lb/h		536,419	536,419	557,143	561,875	562,889	562,889	524,643	537,433	537,433			0	1,014	38,469	4,732	0					lb/h	Carbon di oxide
Oxygen	lb/h		177,258	177,258	184,160	184,880	187,125	186,709	174,023	178,682	178,682		9,541	0	2,245	12,790	720	0		2,731		194	lb/h	Oxygen
Moisture	lb/h		270,167	270,167	280,703	284,682	285,784	286,486	267,021	272,656	272,656			0	1,102	19,517	3,979	265			819		lb/h	Moisture
Sulfur di oxide	lb/h		9,934	9,934	10,312	10,312	10,312	10,213	9,519	9,835	9,835			0	0	704		0					lb/h	Sulfur di oxide
Sulfur tri oxide	lb/h		0	0	6	6	6	130	121	124	124				0	9							lb/h	Sulfur trioxide
Nitrogen oxide	lb/h		0	0	0	0	0	0	0	0	0				0	0							lb/h	Nitrogen oxide
Nitrogen di oxide	lb/h		1,389	1,389	1,384	1,398	1,398	204	190	210	208			0	0	15	14	0					lb/h	Nitrogen di oxide
Argon	lb/h		0	0	8	8	167	167	156	159	159				159	11							lb/h	Argon
Ammonia	lb/h		0	0	0	0	442	5	4	5	5				0	0							lb/h	Ammonia
Particulate	lb/h		77	77	80	80	80	80		77	77				0	6							lb/h	Particulate
Urea	lb/h																				819		lb/h	Urea
Total	lb/h		3,027,072	3,027,072	3,144,449	3,186,893	3,201,237	3,201,008	2,983,441	3,041,469	3,041,467		40,967	0	13,902	217,707	42,444	442		11,726	1,638	832	lb/h	Total
Composition																								Composition
Nitrogen	Mass-parts		0.671	0.671	0.671	0.673	0.673	0.673	0.673	0.671	0.671		0.767		0.675	0.671	0.777			0.767		0.767	Mass-parts	Nitrogen
Carbon di oxide	Mass-parts		0.177	0.177	0.177	0.176	0.176	0.176	0.176	0.177	0.177		0.000		0.073	0.177	0.111						Mass-parts	Carbon di oxide
Oxygen	Mass-parts		0.059	0.059	0.059	0.058	0.058	0.058	0.058	0.059	0.059		0.233		0.161	0.059	0.017			0.233		0.233	Mass-parts	Oxygen
Moisture	Mass-parts		0.089	0.089	0.089	0.089	0.089	0.089	0.089	0.090	0.090		0.000		0.079	0.090	0.094				0.5		Mass-parts	Moisture
Sulfur di oxide	Mass-parts		0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003		0.000		0.000	0.003	0.000						Mass-parts	Sulfur di oxide
Sulfur tri oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Sulfur trioxide
Nitrogen oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen oxide
Nitrogen di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen di oxide
Argon	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.011	0.000	0.000						Mass-parts	Argon
Ammonia	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Ammonia
Particulate	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Particulate
Urea	Mass-parts																				0.5		Mass-parts	Urea
Total	Mass-parts		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000		1.000	0.000	0.989	1.000	1.000	0.000		1.000	1.000	1.000	Mass-parts	Total
Density	kg/Nm^3		1.281	1.281	1.281	1.281	1.280	1.280	1.280	1.280	1.280													
Cp	kJ/kgK		1.104243094	1.1042431	1.1351465	1.142572233	1.14257223	1.142572233	1.142572233	1.111950928	1.111950928												kJ/kgK	Cp
Heat Content	MW		70.023	70.023	122.082	135.591	136.201	136.201	126.938	83.598	83.598	12.624							0.976				MW	Heat Content
	MMBTU/hr		238.988	238.988	416.667	462.771	464.854	464.854	433.241	285.319	285.319	43.087							3.331					
NO_2	lbs/hour		1388.7665	1388.7665	1384.0464	1398.2822	1398.2822	203.5779	189.7458	210.3873	208.3150					14.9							lbs/hour	NO_2
NO_2	kg/h		630.5000	630.5000	628.3571	634.8201	634.8201	92.4244	86.1446	95.5158	94.5750					6.8							kg/h	NO_2
NO_2	Nm^3 / hour		307.2	307.2	306.1	309.3	309.3	45.0	42.0	46.5	46.1					3.3								
NO + NO_2 @ actual O_2	PPM		286.3	286.3	274.7	273.7	272.4	39.7	39.7	43.2	42.7					42.7								
NO + NO_2 @ 3 % O_2	PPM		327.3	327.3	314.1	311.9	311.2	45.3	45.3	49.4	48.9													
						NO2 Balance Check																		
Eta NOx		0.850	0.8500			kg/h	lbs/hr																	

MRY 2	Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21
	ESP Outlet	ESP Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air
Eta NOx reactor		0.8544			0.0	0															

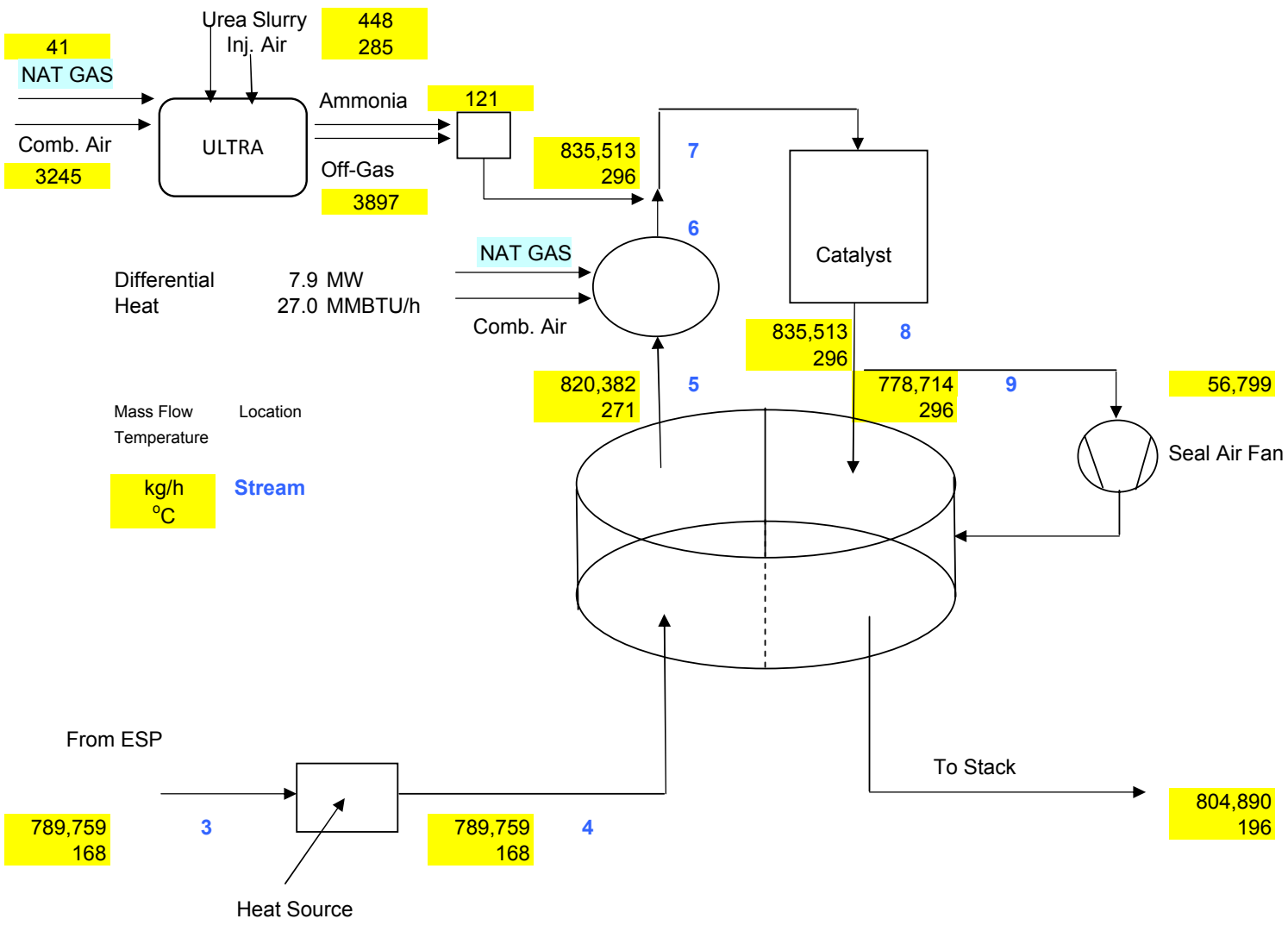
MRY 1 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



MRY 1		Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21		
		FGD Outlet	FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air		
Volumetric flow rate vol.	Nm^3/h		688,272	688,272	714,960	725,054	728,310	728,392	678,935	691,763	691,763	724	9,363	158	3,097	49,517	10,087		52	2,521		221	Nm^3/h	Volumetric flow rate vol.
Volumetric flow rate vol.	scfm		433,924	433,924	450,750	457,114	459,167	459,218	428,038	436,126	436,126	456	5,903	100	1,953	31,218	6,359		33	1,589		140	scfm	Volumetric flow rate vol.
Volumetric flow rate vol.	acfm		478,587	478,587	817,138	866,311	872,297	878,746	820,075	541,960	541,960												acfm	Volumetric flow rate vol.
Mass Flow	kg/h		850,442	850,442	883,419	895,904	899,921	899,921	838,758	866,945	866,945	564	11,921	121	3,897	61,164	12,485	121	41	3,245	448	285	kg/h	Mass Flow
Mass Flow	lb/hour		1,873,220	1,873,220	1,945,856	1,973,356	1,982,206	1,982,206	1,847,484	1,909,570	1,909,570	1,243	26,257	266	8,584	134,722	27,500	266	90	7,148	986	628	lb/hour	Mass Flow
Temperature	Degree F	143	143	150	520	562	562	562	562	196	196												Degree F	Temperature
Temperature	Degree C		62	66	271	295	295	295	295	91	91												Degree C	Temperature
Pressure	iwg		14.5	13.5	10	9	8	5	4.5	0	0													Pressure
Composition																								Composition
Nitrogen	Vol-parts		0.6258	0.6258	0.6258	0.6278	0.6279	0.6281	0.6281	0.6260	0.6260		0.7900		0.6810		0.7705	0.2999		0.7900		0.7900	Vol-parts	Nitrogen
Carbon di oxide	Vol-parts		0.1045	0.1045	0.1045	0.1040	0.1037	0.1037	0.1037	0.1041	0.1041				0.0458		0.0703						Vol-parts	Carbon di oxide
Oxygen	Vol-parts		0.0493	0.0493	0.0494	0.0489	0.0493	0.0491	0.0491	0.0495	0.0495		0.2100		0.1432		0.0147			0.2100		0.2100	Vol-parts	Oxygen
Moisture	Vol-parts		0.2201	0.2201	0.2201	0.2190	0.2186	0.2189	0.2189	0.2202	0.2202				0.1220		0.1445	0.7001					Vol-parts	Moisture
Sulfur di oxide	Vol-parts		0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001						0.0000						Vol-parts	Sulfur di oxide
Sulfur tri oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Sulfur trioxide
Nitrogen oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen oxide
Nitrogen di oxide	Vol-parts		0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen di oxide
Argon	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				0.0081		0.0000						Vol-parts	Argon
Ammonia	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Ammonia
Total			1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000		1.0000		1.0000		1.0000	1.0000		1.0000		1.0000	Vol-parts	Total
Volumetric Flow			0																					Volumetric Flow
Nitrogen	Nm^3/h		430,691	430,691	447,407	455,173	457,283	457,521	426,456	433,036	433,036		7,397		2,109	30,997	7,771	39		1,991		175	Nm^3/h	Nitrogen
Carbon di oxide	Nm^3/h		71,902	71,902	74,681	75,390	75,532	75,532	70,403	72,044	72,044				142	5,157	709						Nm^3/h	Carbon di oxide
Oxygen	Nm^3/h		33,964	33,964	35,288	35,436	35,880	35,800	33,369	34,251	34,251		1,966		444	2,452	148			529		47	Nm^3/h	Oxygen
Moisture	Nm^3/h		151,484	151,484	157,364	158,821	159,199	159,437	148,612	152,332	152,332				378	10,904	1,458	90					Nm^3/h	Moisture
Sulfur di oxide	Nm^3/h		45	45	47	47	47	46	43	45	45				0	3	0						Nm^3/h	Sulfur di oxide
Sulfur tri oxide	Nm^3/h		0	0	0	0	0	0	0	0	0				0	0	0						Nm3/h	Sulfur trioxide
Nitrogen oxide	Nm^3/h		0	0	0	0	0	0	0	0	0				0	0	0						Nm3/h	Nitrogen oxide
Nitrogen dioxide	Nm^3/h		185	185	184	186	186	27	25	28	28				0	2	0						Nm^3/h	Nitrogen di oxide
Argon	Nm^3/h		0	0	1	1	26	26	24	25	25				25	2	0						Nm3/h	Argon
Ammonia	Nm^3/h		0	0	0	0	158	2	2	2	2				0	0	0						Nm3/h	Ammonia
Total	Nm^3/h		688,272	688,272	714,971	725,054	728,310	728,392	678,935	691,763	691,763		9,363		3,097	49,517	10,087	129		2,521		221	Nm^3/h	Total
Mass Flow																								Mass Flow
Nitrogen	kg/h	1,076,862	538,431	538,431	559,328	569,038	571,675	571,973	533,137	541,362	541,362		9,247		2,637	38,751	9,710	48		2,489		219	kg/h	Nitrogen
Carbon di oxide	kg/h	282,412	141,206	141,206	146,662	148,055	148,333	148,333	138,262	141,485	141,485				279	10,128	1,392						kg/h	Carbon di oxide
Oxygen	kg/h	96,998	48,499	48,499	50,388	50,600	51,234	51,120	47,649	48,908	48,908		2,808		633	3,501	212			756		66	kg/h	Oxygen
Moisture	kg/h	243,564	121,782	121,782	126,509	127,680	127,984	128,176	119,473	122,464	122,464				304	8,766	1,171	72			224		kg/h	Moisture
Sulfur di oxide	kg/h	258	129	129	134	134	134	133	124	128	128				0	9							kg/h	Sulfur di oxide
Sulfur tri oxide	kg/h		0	0	0	0	0	2	2	2	2				0	0							kg/h	Sulfur trioxide
Nitrogen oxide	kg/h		0	0	0	0	0	0	0	0	0				0	0							kg/h	Nitrogen oxide
Nitrogen di oxide	kg/h	758	379	379	378	382	382	56	52	57	57				0	4	4						kg/h	Nitrogen di oxide
Argon	kg/h		0	0	2	2	47	47	44	44	44				44	3							kg/h	Argon
Ammonia	kg/h		0	0	0	0	121	1	1	1	1			121	0	0							kg/h	Ammonia
Particulate	kg/h	32	16	16	17	17	17	17	15	16	16				0	1							kg/h	Particulate
Urea	kg/h																				224		kg/h	Urea
Total	kg/h	1,700,884	850,442	850,442	883,419	895,908	899,926	899,857	838,758	854,468	854,467		12,054	121	3,897	61,164	12,489	121		3,245	448	285	kg/h	Total
Nitrogen	lb/h		1,185,971	1,185,971	1,232,000	1,253,388	1,259,196	1,259,852	1,174,310	1,192,428	1,192,428		20,367	0	5,808	85,355	21,387	106		5,483		482	lb/h	Nitrogen
Carbon di oxide	lb/h		311,026	311,026	323,044	326,111	326,725	326,725	304,541	311,640	311,640			0	614	22,308	3,067	0					lb/h	Carbon di oxide
Oxygen	lb/h		106,826	106,826	110,988	111,454	112,849	112,599	104,954	107,727	107,727		6,184	0	1,395	7,711	467	0		1,665		146	lb/h	Oxygen
Moisture	lb/h		268,242	268,242	278,655	281,234	281,903	282,325	263,156	269,745	269,745			0	669	19,309	2,579	159			493		lb/h	Moisture
Sulfur di oxide	lb/h		284	284	295	295	295	292	272	281	281			0	0	20		0					lb/h	Sulfur di oxide
Sulfur tri oxide	lb/h		0	0	0	0	0	4	3	4	4				0	0							lb/h	Sulfur trioxide
Nitrogen oxide	lb/h		0	0	0	0	0	0	0	0	0				0	0							lb/h	Nitrogen oxide
Nitrogen di oxide	lb/h		835	835	832	841	841	122	114	127	125			0	0	9	9	0					lb/h	Nitrogen di oxide
Argon	lb/h		0	0	5	5	103	103	96	98	98				98	7							lb/h	Argon
Ammonia	lb/h		0	0	0	0	266	3	3	3	3				0	0							lb/h	Ammonia
Particulate	lb/h		35	35	37	37	37	37		35	35				0	3							lb/h	Particulate
Urea	lb/h																				493		lb/h	Urea
Total	lb/h		1,873,220	1,873,220	1,945,856	1,973,365	1,982,215	1,982,063	1,847,450	1,882,088	1,882,087		26,552	0	8,584	134,722	27,509	266		7,148	986	628	lb/h	Total
Composition																								Composition
Nitrogen	Mass-parts		0.633	0.633	0.633	0.635	0.635	0.636	0.636	0.634	0.634		0.767		0.677	0.634	0.777			0.767		0.767	Mass-parts	Nitrogen
Carbon di oxide	Mass-parts		0.166	0.166	0.166	0.165	0.165	0.165	0.165	0.166	0.166		0.000		0.072	0.166	0.111						Mass-parts	Carbon di oxide
Oxygen	Mass-parts		0.057	0.057	0.057	0.056	0.057	0.057	0.057	0.057	0.057		0.233		0.163	0.057	0.017			0.233		0.233	Mass-parts	Oxygen
Moisture	Mass-parts		0.143	0.143	0.143	0.143	0.142	0.142	0.142	0.143	0.143		0.000		0.078	0.143	0.094				0.5		Mass-parts	Moisture
Sulfur di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Sulfur di oxide
Sulfur tri oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Sulfur trioxide
Nitrogen oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen oxide
Nitrogen di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen di oxide
Argon	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.011	0.000	0.000						Mass-parts	Argon
Ammonia	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Ammonia
Particulate	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Particulate
Urea	Mass-parts																				0.5		Mass-parts	Urea
Total	Mass-parts		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000		1.000	0.000	0.989	1.000	1.000	0.000		1.000	1.000	1.000	Mass-parts	Total
Density	kg/Nm^3		1.236	1.236	1.236	1.236	1.236	1.235	1.235	1.235	1.235													
Cp	kJ/kgK		1.125693116	1.1266306	1.1861124	1.193726213	1.19372621	1.193726213	1.193726213	1.133004044	1.133004044												kJ/kgK	Cp
Heat Content	MW		16.399	17.448	78.939	87.506	87.899	87.899	81.925	24.857	24.857	8.182							0.592				MW	Heat Content
	MMBTU/hr		55.969	59.548	269.419	298.659	299.998	299.998	279.608	84.837	84.837	27.926							2.022					
NO_2	lbs/hour		834.8018	834.8018	831.9646	841.1912	841.1912	122.4702	114.1547	126.5634	125.2203					9.0							lbs/hour	NO_2
NO_2	kg/h		379.0000	379.0000	377.7119	381.9008	381.9008	55.6015	51.8262	57.4598	56.8500					4.1							kg/h	NO_2
NO_2	Nm^3 / hour		184.6	184.6	184.0	186.1	186.1	27.1	25.2	28.0	27.7					2.0								
NO + NO_2 @ actual O_2	PPM		268.3	268.3	257.4	256.6	255.5	37.2	37.2	40.5	40.0					40.0								
NO + NO_2 @ 3 % O_2	PPM		300.6	300.6	288.4	286.7	286.1	41.6	41.6	45.4	44.9													
						NO2 Balance Check																		
Eta NOx		0.850	0.8500			kg/h	lbs/hr																	

MRY 1	Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21
	FGD Outlet	FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air
Eta NOx reactor		0.8544			0.0	0															

MRY 1 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



MRY 1		Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21		
		ESP Outlet	ESP Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air		
Volumetric flow rate vol.	Nm^3/h		616,442	616,442	640,345	649,337	652,592	652,674	608,347	619,933	619,933	644	8,334	158	3,097	44,359	8,979		52	2,521		221	Nm^3/h	Volumetric flow rate vol.
Volumetric flow rate vol.	scfm		388,639	388,639	403,709	409,378	411,430	411,482	383,536	390,840	390,840	406	5,254	100	1,953	27,966	5,661		33	1,589		140	scfm	Volumetric flow rate vol.
Volumetric flow rate vol.	acfm		565,259	565,259	731,859	777,489	783,269	789,069	736,373	624,992	624,992												acfm	Volumetric flow rate vol.
Mass Flow	kg/h		789,759	789,759	820,382	831,496	835,513	835,513	778,714	804,890	804,890	502	10,611	121	3,897	56,799	11,114	121	41	3,245	448	285	kg/h	Mass Flow
Mass Flow	lb/hour		1,739,556	1,739,556	1,807,009	1,831,488	1,840,338	1,840,338	1,715,229	1,772,885	1,772,885	1,107	23,373	265	8,584	125,109	24,479	265	90	7,148	986	628	lb/hour	Mass Flow
Temperature	Degree F	335	335	335	520	564	564	564	564	384	384												Degree F	Temperature
Temperature	Degree C		168	168	271	296	296	296	296	196	196												Degree C	Temperature
Pressure	iwg		14.5	13.5	10	9	8	5	4.5	0	0													Pressure
Composition																								Composition
Nitrogen	Vol-parts		0.6881	0.6881	0.6881	0.6893	0.6890	0.6893	0.6893	0.6880	0.6880		0.7900		0.6810		0.7705	0.2999		0.7900		0.7900	Vol-parts	Nitrogen
Carbon di oxide	Vol-parts		0.1152	0.1152	0.1152	0.1146	0.1143	0.1142	0.1142	0.1148	0.1148				0.0458		0.0703						Vol-parts	Carbon di oxide
Oxygen	Vol-parts		0.0530	0.0530	0.0530	0.0525	0.0529	0.0528	0.0528	0.0532	0.0532		0.2100		0.1432		0.0147			0.2100		0.2100	Vol-parts	Oxygen
Moisture	Vol-parts		0.1419	0.1419	0.1419	0.1419	0.1418	0.1421	0.1421	0.1424	0.1424				0.1220		0.1445	0.7001					Vol-parts	Moisture
Sulfur di oxide	Vol-parts		0.0015	0.0015	0.0015	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014						0.0000						Vol-parts	Sulfur di oxide
Sulfur tri oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Sulfur trioxide
Nitrogen oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen oxide
Nitrogen di oxide	Vol-parts		0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen di oxide
Argon	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				0.0081		0.0000						Vol-parts	Argon
Ammonia	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Ammonia
Total			1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000		1.0000		1.0000		1.0000	1.0000		1.0000		1.0000	Vol-parts	Total
Volumetric Flow			0																					Volumetric Flow
Nitrogen	Nm^3/h		424,187	424,187	440,644	447,558	449,667	449,905	419,350	426,532	426,532		6,584		2,109	30,520	6,918	39		1,991		175	Nm^3/h	Nitrogen
Carbon di oxide	Nm^3/h		71,044	71,044	73,788	74,419	74,561	74,561	69,497	71,186	71,186				142	5,094	631						Nm^3/h	Carbon di oxide
Oxygen	Nm^3/h		32,677	32,677	33,950	34,082	34,525	34,446	32,106	32,963	32,963		1,750		444	2,359	132			529		47	Nm^3/h	Oxygen
Moisture	Nm^3/h		87,446	87,446	90,856	92,153	92,531	92,769	86,468	88,294	88,294				378	6,318	1,298	90					Nm^3/h	Moisture
Sulfur di oxide	Nm^3/h		904	904	938	938	938	929	866	895	895				0	64	0						Nm^3/h	Sulfur di oxide
Sulfur tri oxide	Nm^3/h		0	0	0	0	0	9	9	9	9				0	1	0						Nm3/h	Sulfur trioxide
Nitrogen oxide	Nm^3/h		0	0	0	0	0	0	0	0	0				0	0	0						Nm3/h	Nitrogen oxide
Nitrogen dioxide	Nm^3/h		185	185	184	186	186	27	25	28	28				0	2	0						Nm^3/h	Nitrogen di oxide
Argon	Nm^3/h		0	0	1	1	26	26	24	25	25				25	2	0						Nm3/h	Argon
Ammonia	Nm^3/h		0	0	0	0	158	2	2	2	2				0	0	0						Nm3/h	Ammonia
Total	Nm^3/h		616,442	616,442	640,362	649,337	652,592	652,674	608,347	619,933	619,933		8,334		3,097	44,359	8,979	129		2,521		221	Nm^3/h	Total
Mass Flow																								Mass Flow
Nitrogen	kg/h	1,060,600	530,300	530,300	550,874	559,517	562,154	562,452	524,253	533,231	533,231		8,231		2,637	38,155	8,643	48		2,489		219	kg/h	Nitrogen
Carbon di oxide	kg/h	279,040	139,520	139,520	144,909	146,148	146,427	146,427	136,482	139,799	139,799				279	10,003	1,239						kg/h	Carbon di oxide
Oxygen	kg/h	93,320	46,660	46,660	48,478	48,666	49,300	49,186	45,846	47,069	47,069		2,499		633	3,368	189			756		66	kg/h	Oxygen
Moisture	kg/h	140,600	70,300	70,300	73,042	74,084	74,388	74,579	69,514	70,982	70,982				304	5,079	1,042	72			224		kg/h	Moisture
Sulfur di oxide	kg/h	5,167	2,584	2,584	2,682	2,682	2,682	2,656	2,476	2,558	2,558				0	183							kg/h	Sulfur di oxide
Sulfur tri oxide	kg/h		0	0	2	2	2	34	32	32	32				0	2							kg/h	Sulfur trioxide
Nitrogen oxide	kg/h		0	0	0	0	0	0	0	0	0				0	0							kg/h	Nitrogen oxide
Nitrogen di oxide	kg/h	758	379	379	378	381	381	56	52	57	57				0	4	4						kg/h	Nitrogen di oxide
Argon	kg/h		0	0	2	2	47	47	44	44	44				44	3							kg/h	Argon
Ammonia	kg/h		0	0	0	0	121	1	1	1	1			121	0	0							kg/h	Ammonia
Particulate	kg/h	32	16	16	17	17	17	17	15	16	16				0	1							kg/h	Particulate
Urea	kg/h																				224		kg/h	Urea
Total	kg/h	1,579,517	789,759	789,759	820,382	831,499	835,517	835,454	778,714	793,790	793,790		10,730	121	3,897	56,799	11,117	121		3,245	448	285	kg/h	Total
Nitrogen	lb/h		1,168,062	1,168,062	1,213,379	1,232,417	1,238,225	1,238,880	1,154,742	1,174,518	1,174,518		18,130	0	5,808	84,042	19,038	106		5,483		482	lb/h	Nitrogen
Carbon di oxide	lb/h		307,313	307,313	319,182	321,912	322,526	322,526	300,622	307,927	307,927			0	614	22,034	2,730	0					lb/h	Carbon di oxide
Oxygen	lb/h		102,775	102,775	106,779	107,195	108,590	108,340	100,982	103,677	103,677		5,505	0	1,395	7,419	415	0		1,665		146	lb/h	Oxygen
Moisture	lb/h		154,846	154,846	160,885	163,181	163,850	164,272	153,115	156,348	156,348			0	669	11,187	2,296	159			493		lb/h	Moisture
Sulfur di oxide	lb/h		5,691	5,691	5,907	5,907	5,907	5,850	5,453	5,634	5,634			0	0	403		0					lb/h	Sulfur di oxide
Sulfur tri oxide	lb/h		0	0	4	4	4	75	70	71	71				0	5							lb/h	Sulfur trioxide
Nitrogen oxide	lb/h		0	0	0	0	0	0	0	0	0				0	0							lb/h	Nitrogen oxide
Nitrogen di oxide	lb/h		835	835	832	840	840	122	114	126	125			0	0	9	8	0					lb/h	Nitrogen di oxide
Argon	lb/h		0	0	5	5	103	103	96	98	98				98	7							lb/h	Argon
Ammonia	lb/h		0	0	0	0	266	3	3	3	3				0	0							lb/h	Ammonia
Particulate	lb/h		35	35	37	37	37	37		35	35				0	3							lb/h	Particulate
Urea	lb/h																				493		lb/h	Urea
Total	lb/h		1,739,556	1,739,556	1,807,009	1,831,497	1,840,346	1,840,207	1,715,195	1,748,437	1,748,436		23,635	0	8,584	125,109	24,487	265		7,148	986	628	lb/h	Total
Composition																								Composition
Nitrogen	Mass-parts		0.671	0.671	0.671	0.673	0.673	0.673	0.673	0.672	0.672		0.767		0.677	0.672	0.777			0.767		0.767	Mass-parts	Nitrogen
Carbon di oxide	Mass-parts		0.177	0.177	0.177	0.176	0.175	0.175	0.175	0.176	0.176		0.000		0.072	0.176	0.111						Mass-parts	Carbon di oxide
Oxygen	Mass-parts		0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059		0.233		0.163	0.059	0.017			0.233		0.233	Mass-parts	Oxygen
Moisture	Mass-parts		0.089	0.089	0.089	0.089	0.089	0.089	0.089	0.089	0.089		0.000		0.078	0.089	0.094				0.5		Mass-parts	Moisture
Sulfur di oxide	Mass-parts		0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003		0.000		0.000	0.003	0.000						Mass-parts	Sulfur di oxide
Sulfur tri oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Sulfur trioxide
Nitrogen oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen oxide
Nitrogen di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen di oxide
Argon	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.011	0.000	0.000						Mass-parts	Argon
Ammonia	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Ammonia
Particulate	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Particulate
Urea	Mass-parts																				0.5		Mass-parts	Urea
Total	Mass-parts		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000		1.000	0.000	0.989	1.000	1.000	0.000		1.000	1.000	1.000	Mass-parts	Total
Density	kg/Nm^3		1.281	1.281	1.281	1.281	1.280	1.280	1.280	1.280	1.280													
Cp	kJ/kgK		1.104654151	1.1046542	1.1349059	1.142477377	1.14247738	1.142477377	1.142477377	1.11237214	1.11237214												kJ/kgK	Cp
Heat Content	MW		40.793	40.793	70.142	78.046	78.423	78.423	73.092	48.631	48.631	7.283							0.592				MW	Heat Content
	MMBTU/hr		139.227	139.227	239.394	266.372	267.659	267.659	249.463	165.977	165.977	24.858							2.022					
NO_2	lbs/hour		834.8018	834.8018	831.9623	840.1753	840.1753	122.3223	114.0148	126.4155	125.2203					9.0							lbs/hour	NO_2
NO_2	kg/h		379.0000	379.0000	377.7109	381.4396	381.4396	55.5343	51.7627	57.3926	56.8500					4.1							kg/h	NO_2
NO_2	Nm^3 / hour		184.6	184.6	184.0	185.8	185.8	27.1	25.2	28.0	27.7					2.0								
NO + NO_2 @ actual O_2	PPM		299.5	299.5	287.4	286.2	284.8	41.5	41.5	45.1	44.7					44.7								
NO + NO_2 @ 3 % O_2	PPM		343.4	343.4	329.5	327.0	326.3	47.5	47.5	51.8	51.3													
						NO2 Balance Check																		
Eta NOx		0.850	0.8500			kg/h	lbs/hr																	

MRY 1	Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21
	ESP Outlet	ESP Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air
Eta NOx reactor		0.8544			0.0	0															

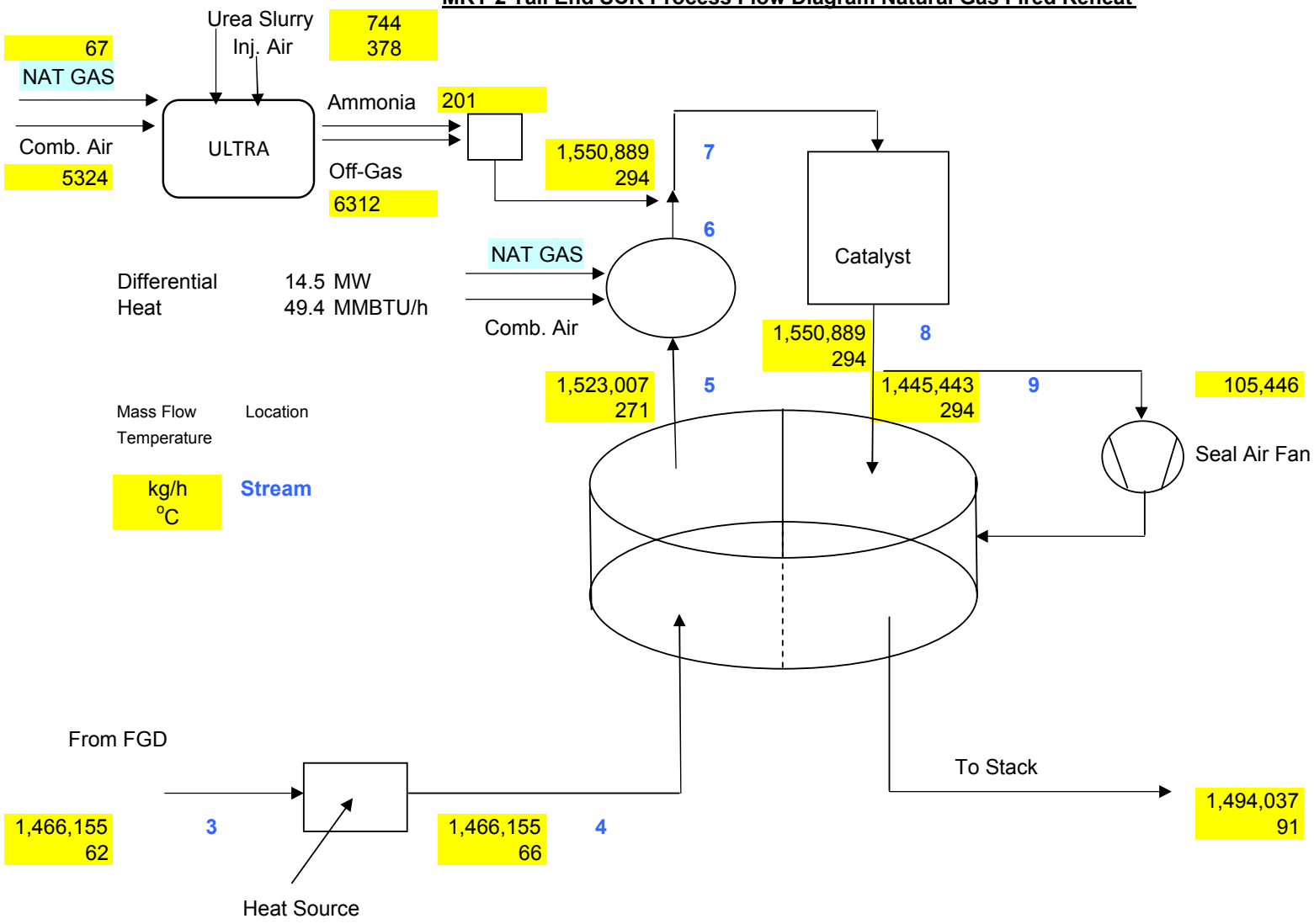
Burns & McDonnell

Client: **Confidential**

Subject: **Hypothetical SCR Reactor Arrangements**

	Unit 1	**Unit 1**	**Unit 2**	**Unit 2**
SCR	**Low Dust**	**Tail End**	**Low Dust**	**Tail End**
Flue Gas Flow (lb/hr)	1,815,800 Per reactor	1,993,400 Per reactor	3,159,000 Per reactor	3,369,300 Per reactor
Nm^3/hr	643,500	731,800	1,119,560	1,231,630
Flue Gas Temperature	630F	600F	630	600
# Reactors	2	2	2	2
Reactor				
# modules	45 (5 * 9)	45 (5 * 9)	84 (7 * 12)	77 (7 * 11)
Dimensions per reactor (approx)	10,085 mm * 9,210 mm	10,085 mm * 9,210 mm	14,025 mm * 12,200 mm	14,025 mm * 11,200 mm
	33’ * 30’	33’ * 30’	46’ * 40’	46’ * 37’
Module Layers	2 + 1	2 + 1	2 + 1	2 + 1
Initial Volume (m^3)	132	160	249	249

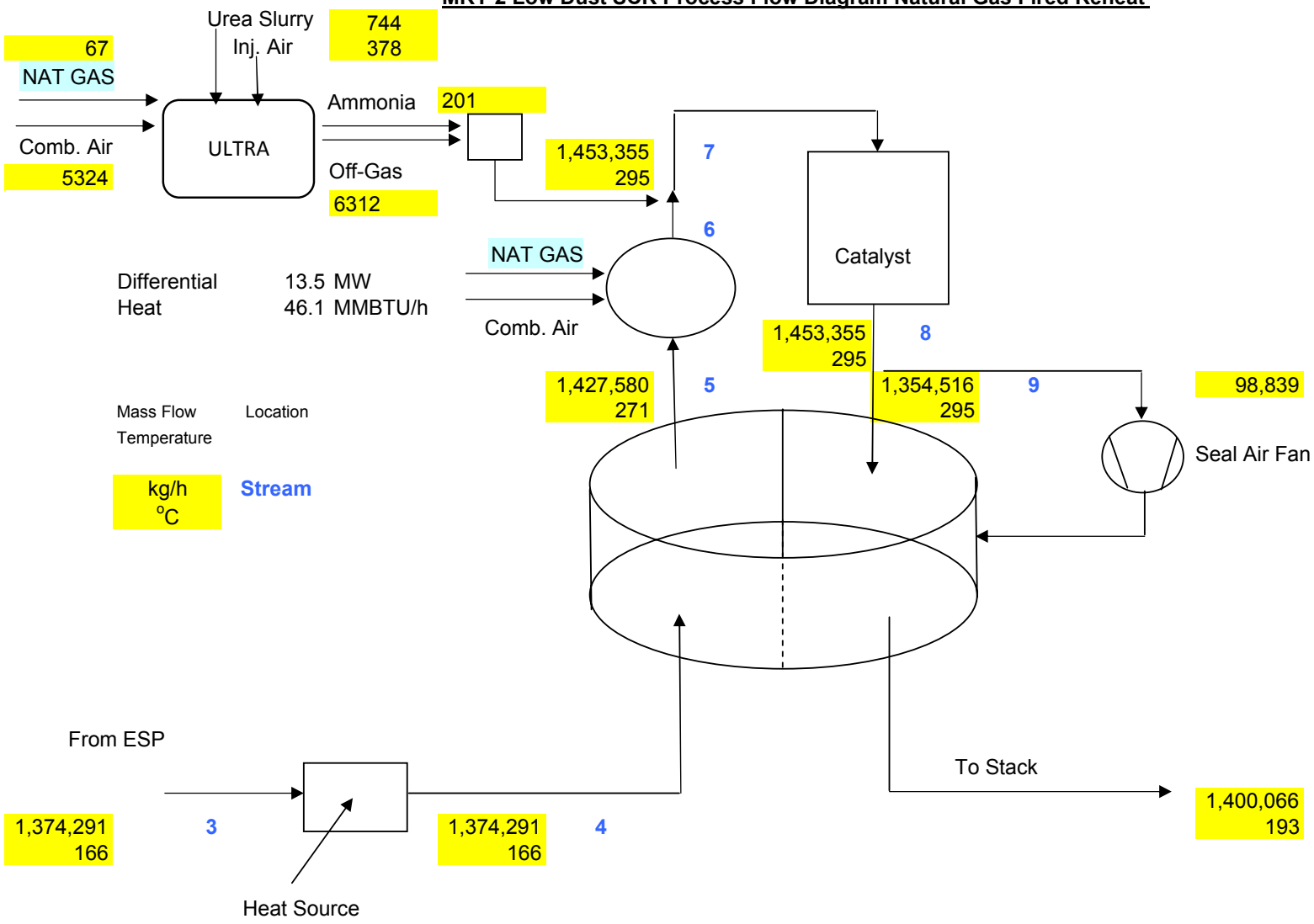
MRY 2 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



MRY 2		Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21		
		FGD Outlet	FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air		
Volumetric flow rate vol.	Nm^3/h		1,180,582	1,180,582	1,226,360	1,243,639	1,248,920	1,249,057	1,164,213	1,186,256	1,186,256	1,239	16,026	263	5,018	84,937	17,265		86	4,135		293	Nm^3/h	Volumetric flow rate vol.
Volumetric flow rate vol.	scfm		744,304	744,304	773,165	784,058	787,388	787,474	733,984	747,881	747,881	781	10,103	166	3,164	53,549	10,885		54	2,607		185	scfm	Volumetric flow rate vol.
Volumetric flow rate vol.	acfm		820,913	820,913	1,401,624	1,485,060	1,494,958	1,506,005	1,405,413	929,368	929,368												acfm	Volumetric flow rate vol.
Mass Flow	kg/h		1,466,155	1,466,155	1,523,007	1,544,376	1,550,889	1,550,889	1,445,443	1,494,037	1,494,037	966	20,404	201	6,312	105,446	21,370	201	67	5,324	744	378	kg/h	Mass Flow
Mass Flow	lb/hour		3,229,416	3,229,416	3,354,640	3,401,710	3,416,054	3,416,054	3,183,794	3,290,830	3,290,830	2,128	44,942	442	13,902	232,260	47,070	442	148	11,726	1,638	832	lb/hour	Mass Flow
Temperature	Degree F	143	143	150	520	562	562	562	562	196	196												Degree F	Temperature
Temperature	Degree C		62	66	271	294	294	294	294	91	91												Degree C	Temperature
Pressure	iwg		14.5	13.5	10	9	8	5	4.5	0	0													Pressure
Composition																								Composition
Nitrogen	Vol-parts		0.6346	0.6346	0.6346	0.6365	0.6365	0.6368	0.6368	0.6348	0.6348		0.7900		0.6790		0.7705	0.2999		0.7900		0.7900	Vol-parts	Nitrogen
Carbon di oxide	Vol-parts		0.1063	0.1063	0.1063	0.1058	0.1055	0.1055	0.1055	0.1060	0.1060				0.0467		0.0703						Vol-parts	Carbon di oxide
Oxygen	Vol-parts		0.0496	0.0496	0.0496	0.0492	0.0495	0.0494	0.0494	0.0498	0.0498		0.2100		0.1422		0.0147			0.2100		0.2100	Vol-parts	Oxygen
Moisture	Vol-parts		0.2091	0.2091	0.2091	0.2082	0.2078	0.2081	0.2081	0.2093	0.2093				0.1240		0.1445	0.7001					Vol-parts	Moisture
Sulfur di oxide	Vol-parts		0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001						0.0000						Vol-parts	Sulfur di oxide
Sulfur tri oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Sulfur trioxide
Nitrogen oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen oxide
Nitrogen di oxide	Vol-parts		0.0003	0.0003	0.0002	0.0002	0.0002	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen di oxide
Argon	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				0.0081		0.0000						Vol-parts	Argon
Ammonia	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Ammonia
Total			1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000		1.0000		1.0000		1.0000	1.0000		1.0000		1.0000	Vol-parts	Total
Volumetric Flow			0																					Volumetric Flow
Nitrogen	Nm^3/h		749,220	749,220	778,295	791,589	794,996	795,393	741,365	753,019	753,019		12,660		3,407	53,917	13,302	64		3,267		232	Nm^3/h	Nitrogen
Carbon di oxide	Nm^3/h		125,507	125,507	130,357	131,571	131,805	131,805	122,852	125,741	125,741				234	9,003	1,214						Nm^3/h	Carbon di oxide
Oxygen	Nm^3/h		58,606	58,606	60,888	61,142	61,855	61,723	57,530	59,058	59,058		3,365		714	4,229	254			868		62	Nm^3/h	Oxygen
Moisture	Nm^3/h		246,863	246,863	256,451	258,944	259,566	259,963	242,305	248,269	248,269				622	17,776	2,495	150					Nm^3/h	Moisture
Sulfur di oxide	Nm^3/h		79	79	82	82	82	81	75	78	78				0	6	0						Nm^3/h	Sulfur di oxide
Sulfur tri oxide	Nm^3/h		0	0	0	0	0	1	1	1	1				0	0	0						Nm3/h	Sulfur trioxide
Nitrogen oxide	Nm^3/h		0	0	0	0	0	0	0	0	0				0	0	0						Nm3/h	Nitrogen oxide
Nitrogen dioxide	Nm^3/h		307	307	306	310	310	45	42	47	46				0	3	0						Nm^3/h	Nitrogen di oxide
Argon	Nm^3/h		0	0	2	2	42	42	40	40	40				40	3	0						Nm3/h	Argon
Ammonia	Nm^3/h		0	0	0	0	263	3	3	3	3				0	0	0						Nm3/h	Ammonia
Total	Nm^3/h		1,180,582	1,180,582	1,226,381	1,243,639	1,248,920	1,249,057	1,164,213	1,186,256	1,186,256		16,026		5,018	84,937	17,265	214		4,135		293	Nm^3/h	Total
Mass Flow																								Mass Flow
Nitrogen	kg/h	1,873,285	936,643	936,643	972,990	989,610	993,870	994,366	926,822	941,391	941,391		15,827		4,259	67,405	16,620	80		4,084		290	kg/h	Nitrogen
Carbon di oxide	kg/h	492,954	246,477	246,477	256,003	258,386	258,847	258,847	241,264	246,937	246,937				460	17,681	2,383						kg/h	Carbon di oxide
Oxygen	kg/h	167,370	83,685	83,685	86,943	87,306	88,325	88,136	82,150	84,331	84,331		4,806		1,019	6,038	363			1,240		88	kg/h	Oxygen
Moisture	kg/h	396,920	198,460	198,460	206,168	208,172	208,672	208,991	194,795	199,590	199,590				500	14,291	2,004	120			372		kg/h	Moisture
Sulfur di oxide	kg/h	450	225	225	234	234	234	231	216	223	223				0	16							kg/h	Sulfur di oxide
Sulfur tri oxide	kg/h		0	0	0	0	0	3	3	3	3				0	0							kg/h	Sulfur trioxide
Nitrogen oxide	kg/h		0	0	0	0	0	0	0	0	0				0	0							kg/h	Nitrogen oxide
Nitrogen di oxide	kg/h	1,261	631	631	628	636	636	93	86	96	95				0	7	7						kg/h	Nitrogen di oxide
Argon	kg/h		0	0	4	4	76	76	71	72	72				72	5							kg/h	Argon
Ammonia	kg/h		0	0	0	0	201	2	2	2	2			201	0	0							kg/h	Ammonia
Particulate	kg/h	70	35	35	36	36	36	36	34	35	35				0	3							kg/h	Particulate
Urea	kg/h																				372		kg/h	Urea
Total	kg/h	2,932,310	1,466,155	1,466,155	1,523,007	1,544,383	1,550,896	1,550,781	1,445,443	1,472,681	1,472,680		20,633	201	6,312	105,446	21,377	201		5,324	744	378	kg/h	Total
Nitrogen	lb/h		2,063,089	2,063,089	2,143,151	2,179,758	2,189,140	2,190,232	2,041,459	2,073,549	2,073,549		34,862	0	9,382	148,469	36,607	177		8,995		638	lb/h	Nitrogen
Carbon di oxide	lb/h		542,901	542,901	563,883	569,133	570,147	570,147	531,419	543,915	543,915			0	1,014	38,945	5,249	0					lb/h	Carbon di oxide
Oxygen	lb/h		184,328	184,328	191,505	192,304	194,549	194,133	180,947	185,752	185,752		10,585	0	2,245	13,300	799	0		2,731		194	lb/h	Oxygen
Moisture	lb/h		437,137	437,137	454,114	458,528	459,630	460,333	429,064	439,625	439,625			0	1,102	31,478	4,414	265			819		lb/h	Moisture
Sulfur di oxide	lb/h		496	496	514	514	514	510	475	491	491			0	0	35		0					lb/h	Sulfur di oxide
Sulfur tri oxide	lb/h		0	0	0	0	0	6	6	6	6				0	0							lb/h	Sulfur trioxide
Nitrogen oxide	lb/h		0	0	0	0	0	0	0	0	0				0	0							lb/h	Nitrogen oxide
Nitrogen di oxide	lb/h		1,389	1,389	1,384	1,400	1,400	204	190	211	208			0	0	15	16	0					lb/h	Nitrogen di oxide
Argon	lb/h		0	0	8	8	167	167	156	159	159				159	11							lb/h	Argon
Ammonia	lb/h		0	0	0	0	442	5	5	5	5				0	0							lb/h	Ammonia
Particulate	lb/h		77	77	80	80	80	80		77	77				0	6							lb/h	Particulate
Urea	lb/h																				819		lb/h	Urea
Total	lb/h		3,229,416	3,229,416	3,354,640	3,401,726	3,416,070	3,415,817	3,183,720	3,243,791	3,243,788		45,446	0	13,902	232,260	47,086	442		11,726	1,638	832	lb/h	Total
Composition																								Composition
Nitrogen	Mass-parts		0.639	0.639	0.639	0.641	0.641	0.641	0.641	0.639	0.639		0.767		0.675	0.639	0.777			0.767		0.767	Mass-parts	Nitrogen
Carbon di oxide	Mass-parts		0.168	0.168	0.168	0.167	0.167	0.167	0.167	0.168	0.168		0.000		0.073	0.168	0.111						Mass-parts	Carbon di oxide
Oxygen	Mass-parts		0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057		0.233		0.161	0.057	0.017			0.233		0.233	Mass-parts	Oxygen
Moisture	Mass-parts		0.135	0.135	0.135	0.135	0.135	0.135	0.135	0.136	0.136		0.000		0.079	0.136	0.094				0.5		Mass-parts	Moisture
Sulfur di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Sulfur di oxide
Sulfur tri oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Sulfur trioxide
Nitrogen oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen oxide
Nitrogen di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen di oxide
Argon	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.011	0.000	0.000						Mass-parts	Argon
Ammonia	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Ammonia
Particulate	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Particulate
Urea	Mass-parts																				0.5		Mass-parts	Urea
Total	Mass-parts		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000		1.000	0.000	0.989	1.000	1.000	0.000		1.000	1.000	1.000	Mass-parts	Total
Density	kg/Nm^3		1.242	1.242	1.242	1.242	1.242	1.242	1.242	1.241	1.241													
Cp	kJ/kgK		1.118792829	1.1197279	1.1788636	1.186311705	1.18631171	1.186311705	1.186311705	1.126080331	1.126080331												kJ/kgK	Cp
Heat Content	MW		28.098	29.895	135.259	149.739	150.371	150.371	140.147	42.575	42.575	14.005							0.976				MW	Heat Content
	MMBTU/hr		95.899	102.032	461.638	511.060	513.215	513.215	478.321	145.309	145.309	47.799							3.331					
NO_2	lbs/hour		1388.7665	1388.7665	1384.0495	1399.8420	1399.8420	203.8050	189.9613	210.6144	208.3150					14.9							lbs/hour	NO_2
NO_2	kg/h		630.5000	630.5000	628.3585	635.5283	635.5283	92.5275	86.2425	95.6189	94.5750					6.8							kg/h	NO_2
NO_2	Nm^3 / hour		307.2	307.2	306.1	309.6	309.6	45.1	42.0	46.6	46.1					3.3								
NO + NO_2 @ actual O_2	PPM		260.2	260.2	249.6	249.0	247.9	36.1	36.1	39.3	38.8					38.8								
NO + NO_2 @ 3 % O_2	PPM		292.0	292.0	280.2	278.6	278.1	40.5	40.5	44.1	43.6													
						NO2 Balance Check																		
Eta NOx		0.850	0.8500			kg/h	lbs/hr																	

MRY 2	Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21
	FGD Outlet	FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air
Eta NOx reactor		0.8544			0.1	0															

MRY 2 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



Bowman, Chris

From: Bowman, Chris
Sent: Friday, March 20, 2009 2:55 PM
To: MGialanella@babcockpower.com
Cc: 'bbasile@babcockpower.com'
Subject: FW: Low Dust/Tail End SCR
Attachments: Lignite fuel analysis (1-09).pdf; MRY - Flue Gas Conditions.pdf

The listed SCR COD dates for each unit were incorrect. COD schedule of the low dust or tail end SCR at MRY would be negotiated with vendors to determine the soonest COD date possible.

Have a great weekend,

Christopher Bowman

Development Engineer
Burns & McDonnell Engineering
(816) 333-9400 x5693
cbowman@burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

From: Bowman, Chris
Sent: Thursday, March 19, 2009 9:06 AM
To: MGialanella@babcockpower.com
Cc: barry.basile@babcockpower.com
Subject: RFQ: Low Dust/Tail End SCR

Mario,

As discussed on the phone, Minnkota Power is looking to add an SCR to each existing unit at their Milton R. Young Power Station (MRY). Due to the high sodium content of the coal, we are requesting budgetary equipment quotes of a Low Dust and Tail End SCR arrangement for each unit at MRY. The Low Dust SCR will be located downstream of each units ESP and the Tail End SCR will be located downstream of each units WFGD. The estimated flue gas for each associated option and coal analysis is attached.

General Information:
Unit 1, 257 MWg, cyclone-fired, subcritical, SCR COD December 2010
Unit 2, 477 MWg, cyclone-fired, subcritical, SCR COD December 2011
Fuel: Each unit burns 100% North Dakota Lignite.
Ammonia Reagent: 50% Urea solution
Location: Center, North Dakota – Milton R. Young Station

Each system should be based upon the following components and specifications:

- SCR system w/ gas bypass for maintenance (approx. 12.5% of total gas volume)
- Reactor housing
- Catalyst
- Associated flues and internal flow distribution devices
- Ammonia injection grid
- Hoists and monorails for SCR internal maintenance
- Sonic horns
- Natural gas reheater
- Regenerative gas to gas heat exchanger

- Associated interconnecting piping
- Freight to Center, North Dakota

Provided by others:
- Ductwork to and from SCR
- Structural support steel
- Foundations
- Electrical equipment and controls
- Air compressors
- ID Fans and/or booster fans
- Urea to Ammonia supply system

Please base each systems design assuming guarantees to be provided for NOx reduction as follows:
SCR Inlet NOx: 0.50 lb/MMBtu
Stack Outlet NOx: 0.075 lb/MMBtu
Heat Input (Max / Min):
- Unit 1: 2,995 / 2,744 MMBtu/hr
- Unit 2: 5,158 / 4,885 MMBtu/hr

Information required as soon as possible (estimated):
- Equipment dimensions and layout requirements
- Heat exchanger weights
- Pressure loss for each piece of equipment
- Ammonia consumption, slip rates, and natural gas consumption

We are requesting budgetary pricing of each system by **June 1st** in present day dollars with breakout of the catalyst pricing. Please let us know if you will be able to meet this deadline.

Thank you for your continued assistance and please call if you have any questions.

Christopher Bowman

Development Engineer
Burns & McDonnell Engineering
(816) 333-9400 x5693
cbowman@burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

Please note this effort is currently confidential and should be treated accordingly. Additionally, we do not want any technical papers written and/or published until Burns & McDonnell and Minnkota give written permission.

PROXIMATE ANALYSIS (ASTM, as rec'd)		
Moisture - Enter below in Ultimate Analysis		
Volatile Matter	wt%	**26.07**
Fixed Carbon	wt%	**27.00**
Ash - Enter below in Ultimate Analysis		
		100.00
COAL ULTIMATE ANALYSIS (ASTM, as rec'd)		
Moisture	wt%	**37.75**
Carbon	wt%	**38.56**
Hydrogen	wt%	**2.69**
Nitrogen	wt%	**0.58**
Chlorine	wt%	**0.00**
Sulfur	wt%	**1.30**
Ash	wt%	**9.18**
Oxygen	wt%	**9.94**
TOTAL	wt%	100.00
Modified Mott Spooner HHV (Btu/lb) - ***calc***	Btu/lb	6,767
	lbs SO2/mmBtu	3.847
COAL ASH ANALYSIS (ASTM, as rec'd)		
SiO2	wt%	**27.89**
Al2O3	wt%	**9.78**
TiO2	wt%	**0.40**
Fe2O3	wt%	**9.61**
CaO	wt%	**16.48**
MgO	wt%	**4.70**
Na2O	wt%	**5.50**
K2O	wt%	**0.95**
P2O5	wt%	**0.19**
SO3	wt%	**22.25**
Other Unaccounted for	wt%	**2.25**
TOTAL	wt%	100.00
Hg concentration in Coal	ppm, dry	**0.11**
	lbs Hg/TBtu	10.119

modified U1 FGD design spec

Coal 7, Lignite: 6,767 Btu, 1.3% S, 9.18% ash

Flue Gas Condition		Low Dust SCR		Tail End SCR	
		Unit 1	Unit 2	Unit 1	Unit 2
Location		ESP Outlet	ESP Outlet	FGD Outlet	FGD Outlet
Volumetric flow rate vol.	scfm	388,639	676,283	433,924	744,304
Volumetric flow rate vol.	acfm	565,259	978,672	478,587	820,913
Mass Flow	lb/h	1,739,556	3,027,072	1,873,220	3,229,416
Temperature	Degree F	335	331	143	143
Mass Flow					
Nitrogen	lb/h	1,168,062	2,031,828	1,185,971	2,063,089
Carbon dioxide	lb/h	307,313	536,419	311,026	542,901
Oxygen	lb/h	102,775	177,258	106,826	184,328
Moisture	lb/h	154,846	270,167	268,242	437,137
Sulfur dioxide	lb/h	5,691	9,934	284	496
Sulfur trioxide	lb/h	0	0	0	0
Nitrogen oxide	lb/h	0	0	0	0
Nitrogen dioxide	lb/h	835	1,389	835	1,389
Argon	lb/h	0	0	0	0
Ammonia	lb/h	0	0	0	0
Particulate	lb/h	35	77	35	77
Urea	lb/h				
Total	lb/h	1,739,556	3,027,072	1,873,220	3,229,416

Bowman, Chris

From: Bowman, Chris
Sent: Monday, March 30, 2009 3:43 PM
To: 'MGialanella@babcockpower.com'
Cc: 'bbasile@babcockpower.com'; Blackwood, Dave
Subject: RE: Low Dust/Tail End SCR

Mario,

To clarify our conversation about gas to gas heat exchangers (GGH), it is our understanding that for the tail end SCR arrangements a GGH is needed to heat the WFGD outlet air above the saturation temp to avoid acid mist condensation in the SCR GGH.

Due to SO2 emission limits required, the GGH at the WFGD cannot exceed more than a 2% leakage. If this is cannot be achieved then we would require a “no-leak” type GGH at the FGD, possibly one using a heat transfer fluid in a closed-loop or a direct-fired NG burner. Based on your experience with these projects we will default to your assumption as to which type of GGH would be most economically prudent

The use of steam as a heating source, such as a steam coil, is not an option for this site. Thanks,

Christopher Bowman
Development Engineer
Burns & McDonnell
Direct: 816-333-9400 x5693
Main: 816-333-9400
Fax: 816-333-3690
www.burnsmcd.com
Proud to be one of FORTUNE’s 100 Best Companies To Work For

From: Bowman, Chris
Sent: Monday, March 30, 2009 9:40 AM
To: 'MGialanella@babcockpower.com'
Cc: 'bbasile@babcockpower.com'
Subject: RE: Low Dust/Tail End SCR

Mario,

As mentioned in the phone call today, if you could please provide the information in the following time frame it would be appreciated:

April 10th
Equipment dimensions and layout requirements
Heat exchanger weights

May 1st
Pressure loss for each piece of equipment
Ammonia consumption, slip rates, and natural gas consumption

Thanks,

Christopher Bowman
Development Engineer
cbowman@burnsmcd.com
Proud to be one of FORTUNE’s 100 Best Companies To Work For

From: Bowman, Chris
Sent: Friday, March 20, 2009 2:55 PM
To: MGialanella@babcockpower.com
Cc: 'bbasile@babcockpower.com'
Subject: FW: Low Dust/Tail End SCR

The listed SCR COD dates for each unit were incorrect. COD schedule of the low dust or tail end SCR at MRY would be negotiated with vendors to determine the soonest COD date possible.

Have a great weekend,

Christopher Bowman

Development Engineer
Burns & McDonnell Engineering
(816) 333-9400 x5693
cbowman@burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

From: Bowman, Chris
Sent: Thursday, March 19, 2009 9:06 AM
To: MGialanella@babcockpower.com
Cc: barry.basile@babcockpower.com
Subject: RFQ: Low Dust/Tail End SCR

Mario,

As discussed on the phone, Minnkota Power is looking to add an SCR to each existing unit at their Milton R. Young Power Station (MRY). Due to the high sodium content of the coal, we are requesting budgetary equipment quotes of a Low Dust and Tail End SCR arrangement for each unit at MRY. The Low Dust SCR will be located downstream of each units ESP and the Tail End SCR will be located downstream of each units WFGD. The estimated flue gas for each associated option and coal analysis is attached.

General Information:
Unit 1, 257 MWg, cyclone-fired, subcritical, SCR COD December 2010
Unit 2, 477 MWg, cyclone-fired, subcritical, SCR COD December 2011
Fuel: Each unit burns 100% North Dakota Lignite.
Ammonia Reagent: 50% Urea solution
Location: Center, North Dakota – Milton R. Young Station

Each system should be based upon the following components and specifications:

- SCR system w/ gas bypass for maintenance (approx. 12.5% of total gas volume)
- Reactor housing
- Catalyst
- Associated flues and internal flow distribution devices
- Ammonia injection grid
- Hoists and monorails for SCR internal maintenance
- Sonic horns
- Natural gas reheater
- Regenerative gas to gas heat exchanger
- Associated interconnecting piping
- Freight to Center, North Dakota

Provided by others:

- Ductwork to and from SCR
- Structural support steel
- Foundations
- Electrical equipment and controls
- Air compressors
- ID Fans and/or booster fans
- Urea to Ammonia supply system

Please base each systems design assuming guarantees to be provided for NOx reduction as follows:
SCR Inlet NOx: 0.50 lb/MMBtu
Stack Outlet NOx: 0.075 lb/MMBtu
Heat Input (Max / Min):

- Unit 1: 2,995 / 2,744 MMBtu/hr
- Unit 2: 5,158 / 4,885 MMBtu/hr

Information required as soon as possible (estimated):

- Equipment dimensions and layout requirements
- Heat exchanger weights
- Pressure loss for each piece of equipment
- Ammonia consumption, slip rates, and natural gas consumption

We are requesting budgetary pricing of each system by **June 1st** in present day dollars with breakout of the catalyst pricing. Please let us know if you will be able to meet this deadline.

Thank you for your continued assistance and please call if you have any questions.

Christopher Bowman

Development Engineer
Burns & McDonnell Engineering
(816) 333-9400 x5693
cbowman@burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

Please note this effort is currently confidential and should be treated accordingly. Additionally, we do not want any technical papers written and/or published until Burns & McDonnell and Minnkota give written permission.

Bowman, Chris

From: JWaller@babcockpower.com
Sent: Wednesday, April 01, 2009 2:26 PM
To: Bowman, Chris
Cc: MGialanella@babcockpower.com; mjasinski@babcockpower.com; cerickson@babcockpower.com
Subject: Fw: Low Dust/Tail End SCR

Chris,

We can meet the following dates for the information you requested:

April 17th
Equipment dimensions and layout requirements
Heat exchanger weights

May 1st
Pressure loss for each piece of equipment
Ammonia consumption, slip rates, and natural gas consumption

We will try to improve the April 17th date.

Regards,

Jack Waller
Babcock Power Environmental Inc.
(508) 854-3850

Jack:

Please review the requested dates and advise if we can meet them.

Thanks,

Mario

[IMAGE]

Mario Gialanella
Business Development Manager
Babcock Power Environmental Inc.
172 Highgrove Drive
Suwanee, GA 30024

T: 678 965 5805 F:
M: 678 761 4395

mgialanella@babcockpower.com
http://www.babcockpower.com

----- Forwarded by Mario Gialanella/babcockpower on 03/30/2009 11:21 AM -----

"Bowman, Chris" <cbowman@burnsmcd.com>

03/30/2009 10:40 AM

To <MGialanella@babcockpower.com>
cc <bbasile@babcockpower.com>
Subject RE: Low Dust/Tail End SCR

Mario,

As mentioned in the phone call today, if you could please provide the information in the following time frame it would be appreciated:

April 10th
Equipment dimensions and layout requirements
Heat exchanger weights

May 1st
Pressure loss for each piece of equipment
Ammonia consumption, slip rates, and natural gas consumption

Thanks,

Christopher Bowman
Development Engineer
cbowman@burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

From: Bowman, Chris
Sent: Friday, March 20, 2009 2:55 PM
To: MGialanella@babcockpower.com
Cc: 'bbasile@babcockpower.com'
Subject: FW: Low Dust/Tail End SCR

The listed SCR COD dates for each unit were incorrect. COD schedule of the low dust or tail end SCR at MRY would be negotiated with vendors to determine the soonest COD date possible.

Have a great weekend,

Christopher Bowman

Development Engineer
Burns & McDonnell Engineering
(816) 333-9400 x5693
cbowman@burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

From: Bowman, Chris
Sent: Thursday, March 19, 2009 9:06 AM
To: MGialanella@babcockpower.com
Cc: barry.basile@babcockpower.com
Subject: RFQ: Low Dust/Tail End SCR

Mario,

As discussed on the phone, Minnkota Power is looking to add an SCR to each existing unit at their Milton R. Young Power Station (MRY). Due to the high sodium content of the coal, we are requesting budgetary equipment quotes of a Low Dust and Tail End SCR arrangement for each unit at MRY. The Low Dust SCR will be located downstream of each units ESP and the Tail End SCR will be located downstream of each units WFGD. The estimated flue gas for each associated option and coal analysis is attached.

General Information:
Unit 1, 257 MWg, cyclone-fired, subcritical, SCR COD December 2010
Unit 2, 477 MWg, cyclone-fired, subcritical, SCR COD December 2011
Fuel: Each unit burns 100% North Dakota Lignite.
Ammonia Reagent: 50% Urea solution
Location: Center, North Dakota – Milton R. Young Station

Each system should be based upon the following components and specifications:

- SCR system w/ gas bypass for maintenance (approx. 12.5% of total gas volume)
- Reactor housing
- Catalyst
- Associated flues and internal flow distribution devices
- Ammonia injection grid
- Hoists and monorails for SCR internal maintenance
- Sonic horns
- Natural gas reheater
- Regenerative gas to gas heat exchanger
- Associated interconnecting piping
- Freight to Center, North Dakota

Provided by others:

- Ductwork to and from SCR

- Structural support steel
- Foundations
- Electrical equipment and controls
- Air compressors
- ID Fans and/or booster fans
- Urea to Ammonia supply system

Please base each systems design assuming guarantees to be provided for NOx reduction as follows:
SCR Inlet NOx: 0.50 lb/MMBtu
Stack Outlet NOx: 0.075 lb/MMBtu
Heat Input (Max / Min):

- Unit 1: 2,995 / 2,744 MMBtu/hr
- Unit 2: 5,158 / 4,885 MMBtu/hr

Information required as soon as possible (estimated):

- Equipment dimensions and layout requirements
- Heat exchanger weights
- Pressure loss for each piece of equipment
- Ammonia consumption, slip rates, and natural gas consumption

We are requesting budgetary pricing of each system by **June 1st** in present day dollars with breakout of the catalyst pricing. Please let us know if you will be able to meet this deadline.

Thank you for your continued assistance and please call if you have any questions.

Christopher Bowman

Development Engineer
Burns & McDonnell Engineering
(816) 333-9400 x5693
cbowman@burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

Please note this effort is currently confidential and should be treated accordingly. Additionally, we do not want any technical papers written and/or published until Burns & McDonnell and Minnkota give written permission.

This e-mail and any attachments are intended only for the named recipient(s) and may contain information that is legally privileged, confidential and/or exempt from disclosure under applicable law. If you have received this message in error and

are not the intended recipient(s), you may not retain, copy or use this e-mail or any attachment for any purpose or disclose all or any part of the contents to any other person or entity. Any such dissemination, distribution or copying of this e-mail or its attachments is strictly prohibited. If you are not the intended recipient(s), please immediately notify the sender and permanently delete this e-mail and any attachments from your computer.

[IMAGE] Think before you print.

http://www.babcockpower.com

BabcockPower
ENVIRONMENTAL

Bowman, Chris

From: JWaller@babcockpower.com
Sent: Thursday, April 02, 2009 11:15 AM
To: Bowman, Chris
Cc: cerickson@babcockpower.com; MGialanella@babcockpower.com; mjasinski@babcockpower.com
Subject: RE: Low Dust/Tail End SCR
Attachments: MRY - Flue Gas Conditions Comparison.pdf

Chris,

I've included a summary table below that compares the flue gas conditions we get form our combustion program vs. the table in the RFQ below giving the heat input for U2 and the coal HHV. As you can see they don't match up well, so we'll need some clarification.

Regards,

Jack Waller
Babcock Power Environmental Inc.
(508) 854-3850

"Bowman, Chris" <cbowman@burnsmcd.com>

04/01/2009 03:33 PM

To <JWaller@babcockpower.com>
cc <MGialanella@babcockpower.com>, <mjasinski@babcockpower.com>, <cerickson@babcockpower.com>
Subject RE: Low Dust/Tail End SCR

April 17th will be fine. Thank you for the update.

Christopher Bowman
Development Engineer
Burns & McDonnell
Direct: 816-333-9400 x5693
Main: 816-333-9400
Fax: 816-333-3690
www.burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

From: JWaller@babcockpower.com [mailto:JWaller@babcockpower.com]
Sent: Wednesday, April 01, 2009 2:26 PM
To: Bowman, Chris
Cc: MGialanella@babcockpower.com; mjasinski@babcockpower.com; cerickson@babcockpower.com
Subject: Fw: Low Dust/Tail End SCR

Chris,

We can meet the following dates for the information you requested:

April 17th
Equipment dimensions and layout requirements
Heat exchanger weights

May 1st
Pressure loss for each piece of equipment
Ammonia consumption, slip rates, and natural gas consumption

We will try to improve the April 17th date.

Regards,

Jack Waller
Babcock Power Environmental Inc.
(508) 854-3850

Jack:

Please review the requested dates and advise if we can meet them.

Thanks,

Mario

[IMAGE]

Mario Gialanella
Business Development Manager
Babcock Power Environmental Inc.
172 Highgrove Drive
Suwanee, GA 30024

T: 678 965 5805 F:
M: 678 761 4395

mgialanella@babcockpower.com
http://www.babcockpower.com

----- Forwarded by Mario Gialanella/babcockpower on 03/30/2009 11:21 AM -----

"Bowman, Chris" <cbowman@burnsmcd.com>

03/30/2009 10:40 AM

To <MGialanella@babcockpower.com>
cc <bbasile@babcockpower.com>
Subject RE: Low Dust/Tail End SCR

Mario,

As mentioned in the phone call today, if you could please provide the information in the following time frame it would be appreciated:

April 10th
Equipment dimensions and layout requirements
Heat exchanger weights

May 1st
Pressure loss for each piece of equipment
Ammonia consumption, slip rates, and natural gas consumption

Thanks,

Christopher Bowman
Development Engineer
cbowman@burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

From: Bowman, Chris
Sent: Friday, March 20, 2009 2:55 PM
To: MGialanella@babcockpower.com
Cc: 'bbasile@babcockpower.com'
Subject: FW: Low Dust/Tail End SCR

The listed SCR COD dates for each unit were incorrect. COD schedule of the low dust or tail end SCR at MRY would be negotiated with vendors to determine the soonest COD date possible.

Have a great weekend,

Christopher Bowman

Development Engineer
Burns & McDonnell Engineering
(816) 333-9400 x5693
cbowman@burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

From: Bowman, Chris
Sent: Thursday, March 19, 2009 9:06 AM
To: MGialanella@babcockpower.com
Cc: barry.basile@babcockpower.com
Subject: RFQ: Low Dust/Tail End SCR

Mario,

As discussed on the phone, Minnkota Power is looking to add an SCR to each existing unit at their Milton R. Young Power Station (MRY). Due to the high sodium content of the coal, we are requesting budgetary equipment quotes of a Low Dust and Tail End SCR arrangement for each unit at MRY. The Low Dust SCR will be located downstream of each units ESP and the Tail End SCR will be located downstream of each units WFGD. The estimated flue gas for each associated option and coal analysis is attached.

General Information:
Unit 1, 257 MWg, cyclone-fired, subcritical, SCR COD December 2010
Unit 2, 477 MWg, cyclone-fired, subcritical, SCR COD December 2011
Fuel: Each unit burns 100% North Dakota Lignite.
Ammonia Reagent: 50% Urea solution
Location: Center, North Dakota – Milton R. Young Station

Each system should be based upon the following components and specifications:

- SCR system w/ gas bypass for maintenance (approx. 12.5% of total gas volume)
- Reactor housing
- Catalyst
- Associated flues and internal flow distribution devices
- Ammonia injection grid
- Hoists and monorails for SCR internal maintenance
- Sonic horns
- Natural gas reheater
- Regenerative gas to gas heat exchanger
- Associated interconnecting piping
- Freight to Center, North Dakota

Provided by others:

- Ductwork to and from SCR
- Structural support steel
- Foundations
- Electrical equipment and controls
- Air compressors
- ID Fans and/or booster fans
- Urea to Ammonia supply system

Please base each systems design assuming guarantees to be provided for NOx reduction as follows:
SCR Inlet NOx: 0.50 lb/MMBtu
Stack Outlet NOx: 0.075 lb/MMBtu
Heat Input (Max / Min):

- Unit 1: 2,995 / 2,744 MMBtu/hr
- Unit 2: 5,158 / 4,885 MMBtu/hr

Information required as soon as possible (estimated):

- Equipment dimensions and layout requirements
- Heat exchanger weights
- Pressure loss for each piece of equipment
- Ammonia consumption, slip rates, and natural gas consumption

We are requesting budgetary pricing of each system by **June 1st** in present day dollars with breakout of the catalyst pricing. Please let us know if you will be able to meet this deadline.

Thank you for your continued assistance and please call if you have any questions.

Christopher Bowman

Development Engineer
Burns & McDonnell Engineering
(816) 333-9400 x5693
cbowman@burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

Please note this effort is currently confidential and should be treated accordingly. Additionally, we do not want any technical papers written and/or published until Burns & McDonnell and Minnkota give written permission.

This e-mail and any attachments are intended only for the named recipient(s) and may contain information that is legally privileged, confidential and/or exempt from disclosure under applicable law. If you have received this message in error and are not the intended recipient(s), you may not retain, copy or use this e-mail or any attachment for any purpose or disclose all or any part of the contents to any other person or entity. Any such dissemination, distribution or copying of this e-mail or its attachments is strictly prohibited. If you are not the intended recipient(s), please immediately notify the sender and permanently delete this e-mail and any attachments from your computer.

[IMAGE] Think before you print.

http://www.babcockpower.com

BabcockPower ENVIRONMENTAL

Minnkota Power MRY Station Unit 2

Flue gas provided vs calculated

Compound	Combustion	MRY	Percent
	lb/hr	lb/hr	Difference
N2	3345292.8	2031828	39.26307461
O2	126407.22	178724	41.38749807
CO2	1076954	536419	50.1910947
H2O	515478.52	270167	47.58908637
SO2	19466.024	9934	48.96749297
SO3	416.52491	0	100
TOTAL	5084015.1	3027072	-67.95157493

Bowman, Chris

From: Bowman, Chris
Sent: Tuesday, April 07, 2009 10:03 AM
To: 'JWaller@babcockpower.com'
Cc: cerickson@babcockpower.com; MGialanella@babcockpower.com; mjasinski@babcockpower.com; Blackwood, Dave
Subject: RE: Low Dust/Tail End SCR
Attachments: MRY - Flue Gas Conditions (r2).pdf

To clarify the discrepancy in the flue gas numbers, our numbers were based on the flow to each SCR reactor assuming 2 SCR reactors per unit. Therefore it showed half of the total estimated flow per unit. Attached is an updated flue gas analysis with the total numbers for each unit. Thank you for requesting clarification.

To further explain our numbers we assumed the following in calculations:

Heat Input (MMBtu/hr): Unit 1: 2,955, Unit 2: 5,158
Net Plant Heat Rate (Btu/kWhr): Unit 1: 11,498, Unit 2: 10,813
Percent Excess Air in Boiler: Unit 1: 119%, Unit 2: 128%
Air Heater Leakage: Unit 1: 16%, Unit 2: 8.5%

Please contact me with any questions.

Christopher Bowman
Development Engineer
cbowman@burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

From: JWaller@babcockpower.com [mailto:JWaller@babcockpower.com]
Sent: Thursday, April 02, 2009 11:15 AM
To: Bowman, Chris
Cc: cerickson@babcockpower.com; MGialanella@babcockpower.com; mjasinski@babcockpower.com
Subject: RE: Low Dust/Tail End SCR

Chris,

I've included a summary table below that compares the flue gas conditions we get form our combustion program vs. the table in the RFQ below giving the heat input for U2 and the coal HHV. As you can see they don't match up well, so we'll need some clarification.

Regards,

Jack Waller
Babcock Power Environmental Inc.
(508) 854-3850

"Bowman, Chris" <cbowman@burnsmcd.com>

To <JWaller@babcockpower.com>
cc <MGialanella@babcockpower.com>, <mjasinski@babcockpower.com>,

04/01/2009 03:33 PM <cerickson@babcockpower.com>
Subject RE: Low Dust/Tail End SCR

April 17th will be fine. Thank you for the update.

Christopher Bowman
Development Engineer
Burns & McDonnell
Direct: 816-333-9400 x5693
Main: 816-333-9400
Fax: 816-333-3690
www.burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

From: JWaller@babcockpower.com [mailto:JWaller@babcockpower.com]
Sent: Wednesday, April 01, 2009 2:26 PM
To: Bowman, Chris
Cc: MGialanella@babcockpower.com; mjasinski@babcockpower.com; cerickson@babcockpower.com
Subject: Fw: Low Dust/Tail End SCR

Chris,

We can meet the following dates for the information you requested:

April 17th
Equipment dimensions and layout requirements
Heat exchanger weights

May 1st
Pressure loss for each piece of equipment
Ammonia consumption, slip rates, and natural gas consumption

We will try to improve the April 17th date.

Regards,

Jack Waller
Babcock Power Environmental Inc.
(508) 854-3850

Jack:

Please review the requested dates and advise if we can meet them.

Thanks,

Mario

[IMAGE]

Mario Gialanella
Business Development Manager
Babcock Power Environmental Inc.
172 Highgrove Drive
Suwanee, GA 30024

T: 678 965 5805 F:
M: 678 761 4395

mgialanella@babcockpower.com
http://www.babcockpower.com

----- Forwarded by Mario Gialanella/babcockpower on 03/30/2009 11:21 AM -----

"Bowman, Chris" <cbowman@burnsmcd.com>

03/30/2009 10:40 AM

To <MGialanella@babcockpower.com>
cc <bbasile@babcockpower.com>
Subject RE: Low Dust/Tail End SCR

Mario,

As mentioned in the phone call today, if you could please provide the information in the following time frame it would be appreciated:

April 10th
Equipment dimensions and layout requirements
Heat exchanger weights

May 1st
Pressure loss for each piece of equipment

Ammonia consumption, slip rates, and natural gas consumption

Thanks,

Christopher Bowman
Development Engineer
cbowman@burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

From: Bowman, Chris
Sent: Friday, March 20, 2009 2:55 PM
To: MGialanella@babcockpower.com
Cc: 'bbasile@babcockpower.com'
Subject: FW: Low Dust/Tail End SCR

The listed SCR COD dates for each unit were incorrect. COD schedule of the low dust or tail end SCR at MRY would be negotiated with vendors to determine the soonest COD date possible.

Have a great weekend,

Christopher Bowman

Development Engineer
Burns & McDonnell Engineering
(816) 333-9400 x5693
cbowman@burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

From: Bowman, Chris
Sent: Thursday, March 19, 2009 9:06 AM
To: MGialanella@babcockpower.com
Cc: barry.basile@babcockpower.com
Subject: RFQ: Low Dust/Tail End SCR

Mario,

As discussed on the phone, Minnkota Power is looking to add an SCR to each existing unit at their Milton R. Young Power

Station (MRY). Due to the high sodium content of the coal, we are requesting budgetary equipment quotes of a Low Dust and Tail End SCR arrangement for each unit at MRY. The Low Dust SCR will be located downstream of each units ESP and the Tail End SCR will be located downstream of each units WFGD. The estimated flue gas for each associated option and coal analysis is attached.

General Information:
Unit 1, 257 MWg, cyclone-fired, subcritical, SCR COD December 2010
Unit 2, 477 MWg, cyclone-fired, subcritical, SCR COD December 2011
Fuel: Each unit burns 100% North Dakota Lignite.
Ammonia Reagent: 50% Urea solution
Location: Center, North Dakota – Milton R. Young Station

Each system should be based upon the following components and specifications:

- SCR system w/ gas bypass for maintenance (approx. 12.5% of total gas volume)
- Reactor housing
- Catalyst
- Associated flues and internal flow distribution devices
- Ammonia injection grid
- Hoists and monorails for SCR internal maintenance
- Sonic horns
- Natural gas reheater
- Regenerative gas to gas heat exchanger
- Associated interconnecting piping
- Freight to Center, North Dakota

Provided by others:

- Ductwork to and from SCR
- Structural support steel
- Foundations
- Electrical equipment and controls
- Air compressors
- ID Fans and/or booster fans
- Urea to Ammonia supply system

Please base each systems design assuming guarantees to be provided for NOx reduction as follows:
SCR Inlet NOx: 0.50 lb/MMBtu
Stack Outlet NOx: 0.075 lb/MMBtu
Heat Input (Max / Min):

- Unit 1: 2,995 / 2,744 MMBtu/hr
- Unit 2: 5,158 / 4,885 MMBtu/hr

<u>Information required as soon as possible (estimated):</u>

- Equipment dimensions and layout requirements
- Heat exchanger weights
- Pressure loss for each piece of equipment

- Ammonia consumption, slip rates, and natural gas consumption

We are requesting budgetary pricing of each system by **June 1st** in present day dollars with breakout of the catalyst pricing. Please let us know if you will be able to meet this deadline.

Thank you for your continued assistance and please call if you have any questions.

Christopher Bowman

Development Engineer
Burns & McDonnell Engineering
(816) 333-9400 x5693
cbowman@burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

Please note this effort is currently confidential and should be treated accordingly. Additionally, we do not want any technical papers written and/or published until Burns & McDonnell and Minnkota give written permission.

This e-mail and any attachments are intended only for the named recipient(s) and may contain information that is legally privileged, confidential and/or exempt from disclosure under applicable law. If you have received this message in error and are not the intended recipient(s), you may not retain, copy or use this e-mail or any attachment for any purpose or disclose all or any part of the contents to any other person or entity. Any such dissemination, distribution or copying of this e-mail or its attachments is strictly prohibited. If you are not the intended recipient(s), please immediately notify the sender and permanently delete this e-mail and any attachments from your computer.

[IMAGE] Think before you print.

http://www.babcockpower.com

BabcockPower ENVIRONMENTAL

Estimated Total Gas Flow Per Unit

Flue Gas Condition		Low Dust SCR		Tail End SCR	
		Unit 1	Unit 2	Unit 1	Unit 2
Location		ESP Outlet	ESP Outlet	FGD Outlet	FGD Outlet
Volumetric flow rate vol.	scfm	777,278	1,352,566	867,848	1,488,608
Volumetric flow rate vol.	acfm	1,130,518	1,957,344	957,174	1,641,826
Mass Flow	lb/h	3,479,114	6,054,144	3,746,438	6,458,834
Temperature	Degree F	335	331	143	143
Mass Flow					
Nitrogen	lb/h	2,336,124	4,063,656	2,371,942	4,126,178
Carbon dioxide	lb/h	614,626	1,072,838	622,052	1,085,802
Oxygen	lb/h	205,550	354,516	213,652	368,656
Moisture	lb/h	309,692	540,334	536,484	874,274
Sulfur dioxide	lb/h	11,382	19,868	568	992
Sulfur trioxide	lb/h	0	0	0	0
Nitrogen oxide	lb/h	0	0	0	0
Nitrogen dioxide	lb/h	1,670	2,778	1,670	2,778
Argon	lb/h	0	0	0	0
Ammonia	lb/h	0	0	0	0
Particulate	lb/h	70	154	70	154
Urea	lb/h				
Total	lb/h	3,479,114	6,054,144	3,746,438	6,458,834

Bowman, Chris

From: JWaller@babcockpower.com
Sent: Thursday, April 09, 2009 12:23 PM
To: Bowman, Chris
Cc: cerickson@babcockpower.com; Blackwood, Dave; MGialanella@babcockpower.com; mjasinski@babcockpower.com
Subject: RE: Low Dust/Tail End SCR
Attachments: MRY - Flue Gas Conditions (r2).pdf

Chris,

RE: Tail-end SCR

How much leakage can the unit(s) accept across the FGD heat recovery GGH? This would ultimately affect the SO2 removal efficiency of the absorber(s). The leakage specification greatly affects the overall cost.

Jack Waller
Babcock Power Environmental Inc.
(508) 854-3850

"Bowman, Chris" <cbowman@burnsmcd.com>

04/07/2009 11:03 AM

To <JWaller@babcockpower.com>
cc <cerickson@babcockpower.com>, <MGialanella@babcockpower.com>, <mjasinski@babcockpower.com>, "Blackwood, Dave" <dblackwood@burnsmcd.com>
Subject RE: Low Dust/Tail End SCR

To clarify the discrepancy in the flue gas numbers, our numbers were based on the flow to each SCR reactor assuming 2 SCR reactors per unit. Therefore it showed half of the total estimated flow per unit. Attached is an updated flue gas analysis with the total numbers for each unit. Thank you for requesting clarification.

To further explain our numbers we assumed the following in calculations:

Heat Input (MMBtu/hr): Unit 1: 2,955, Unit 2: 5,158
Net Plant Heat Rate (Btu/kWhr): Unit 1: 11,498, Unit 2: 10,813
Percent Excess Air in Boiler: Unit 1: 119%, Unit 2: 128%
Air Heater Leakage: Unit 1: 16%, Unit 2: 8.5%

Please contact me with any questions.

Christopher Bowman
Development Engineer

cbowman@burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

From: JWaller@babcockpower.com [mailto:JWaller@babcockpower.com]
Sent: Thursday, April 02, 2009 11:15 AM
To: Bowman, Chris
Cc: cerickson@babcockpower.com; MGialanella@babcockpower.com; mjasinski@babcockpower.com
Subject: RE: Low Dust/Tail End SCR

Chris,

I've included a summary table below that compares the flue gas conditions we get form our combustion program vs. the table in the RFQ below giving the heat input for U2 and the coal HHV. As you can see they don't match up well, so we'll need some clarification.

Regards,

Jack Waller
Babcock Power Environmental Inc.
(508) 854-3850

"Bowman, Chris"
<cbowman@burnsmcd.com>

04/01/2009 03:33 PM

To <JWaller@babcockpower.com>
cc <MGialanella@babcockpower.com>, <mjasinski@babcockpower.com>, <cerickson@babcockpower.com>
Subject RE: Low Dust/Tail End SCR

April 17th will be fine. Thank you for the update.

Christopher Bowman
Development Engineer
Burns & McDonnell
Direct: 816-333-9400 x5693
Main: 816-333-9400
Fax: 816-333-3690
www.burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

From: JWaller@babcockpower.com [mailto:JWaller@babcockpower.com]
Sent: Wednesday, April 01, 2009 2:26 PM
To: Bowman, Chris
Cc: MGialanella@babcockpower.com; mjasinski@babcockpower.com; cerickson@babcockpower.com
Subject: Fw: Low Dust/Tail End SCR

Chris,

We can meet the following dates for the information you requested:

April 17th
Equipment dimensions and layout requirements
Heat exchanger weights

May 1st
Pressure loss for each piece of equipment
Ammonia consumption, slip rates, and natural gas consumption

We will try to improve the April 17th date.

Regards,

Jack Waller
Babcock Power Environmental Inc.
(508) 854-3850

Jack:

Please review the requested dates and advise if we can meet them.

Thanks,

Mario

[IMAGE]

Mario Gialanella
Business Development Manager
Babcock Power Environmental Inc.
172 Highgrove Drive
Suwanee, GA 30024

T: 678 965 5805 F:
M: 678 761 4395

mgialanella@babcockpower.com
http://www.babcockpower.com

----- Forwarded by Mario Gialanella/babcockpower on 03/30/2009 11:21 AM -----

"Bowman, Chris" <cbowman@burnsmcd.com>

03/30/2009 10:40 AM

To <MGialanella@babcockpower.com>
cc <bbasile@babcockpower.com>
Subject RE: Low Dust/Tail End SCR

Mario,

As mentioned in the phone call today, if you could please provide the information in the following time frame it would be appreciated:

April 10th
Equipment dimensions and layout requirements
Heat exchanger weights

May 1st
Pressure loss for each piece of equipment
Ammonia consumption, slip rates, and natural gas consumption

Thanks,

Christopher Bowman
Development Engineer
cbowman@burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

From: Bowman, Chris
Sent: Friday, March 20, 2009 2:55 PM
To: MGialanella@babcockpower.com
Cc: 'bbasile@babcockpower.com'
Subject: FW: Low Dust/Tail End SCR

The listed SCR COD dates for each unit were incorrect. COD schedule of the low dust or tail end SCR at MRY would be negotiated with vendors to determine the soonest COD date possible.

Have a great weekend,

Christopher Bowman

Development Engineer
Burns & McDonnell Engineering
(816) 333-9400 x5693
cbowman@burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

From: Bowman, Chris
Sent: Thursday, March 19, 2009 9:06 AM
To: MGialanella@babcockpower.com
Cc: barry.basile@babcockpower.com
Subject: RFQ: Low Dust/Tail End SCR

Mario,

As discussed on the phone, Minnkota Power is looking to add an SCR to each existing unit at their Milton R. Young Power Station (MRY). Due to the high sodium content of the coal, we are requesting budgetary equipment quotes of a Low Dust and Tail End SCR arrangement for each unit at MRY. The Low Dust SCR will be located downstream of each units ESP and the Tail End SCR will be located downstream of each units WFGD. The estimated flue gas for each associated option and coal analysis is attached.

General Information:
Unit 1, 257 MWg, cyclone-fired, subcritical, SCR COD December 2010
Unit 2, 477 MWg, cyclone-fired, subcritical, SCR COD December 2011
Fuel: Each unit burns 100% North Dakota Lignite.
Ammonia Reagent: 50% Urea solution
Location: Center, North Dakota – Milton R. Young Station

Each system should be based upon the following components and specifications:

- SCR system w/ gas bypass for maintenance (approx. 12.5% of total gas volume)
- Reactor housing
- Catalyst
- Associated flues and internal flow distribution devices
- Ammonia injection grid
- Hoists and monorails for SCR internal maintenance
- Sonic horns
- Natural gas reheater
- Regenerative gas to gas heat exchanger
- Associated interconnecting piping
- Freight to Center, North Dakota

Provided by others:

- Ductwork to and from SCR
- Structural support steel
- Foundations
- Electrical equipment and controls
- Air compressors
- ID Fans and/or booster fans
- Urea to Ammonia supply system

Please base each systems design assuming guarantees to be provided for NOx reduction as follows:
SCR Inlet NOx: 0.50 lb/MMBtu
Stack Outlet NOx: 0.075 lb/MMBtu
Heat Input (Max / Min):

- Unit 1: 2,995 / 2,744 MMBtu/hr
- Unit 2: 5,158 / 4,885 MMBtu/hr

<u>Information required as soon as possible (estimated):</u>

- Equipment dimensions and layout requirements
- Heat exchanger weights
- Pressure loss for each piece of equipment
- Ammonia consumption, slip rates, and natural gas consumption

We are requesting budgetary pricing of each system by **June 1st** in present day dollars with breakout of the catalyst pricing. Please let us know if you will be able to meet this deadline.

Thank you for your continued assistance and please call if you have any questions.

Christopher Bowman

Development Engineer
Burns & McDonnell Engineering
(816) 333-9400 x5693
cbowman@burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

Please note this effort is currently confidential and should be treated accordingly. Additionally, we do not want any technical papers written and/or published until Burns & McDonnell and Minnkota give written permission.

This e-mail and any attachments are intended only for the named recipient(s) and may contain information that is legally privileged, confidential and/or exempt from disclosure under applicable law. If you have received this message in error and are not the intended recipient(s), you may not retain, copy or use this e-mail or any attachment for any purpose or disclose all or any part of the contents to any other person or entity. Any such dissemination, distribution or copying of this e-mail or its attachments is strictly prohibited. If you are not the intended recipient(s), please immediately notify the sender and permanently delete this e-mail and any attachments from your computer.

[IMAGE] Think before you print.

http://www.babcockpower.com

BabcockPower ENVIRONMENTAL

Estimated Total Gas Flow Per Unit

Flue Gas Condition		Low Dust SCR		Tail End SCR	
		Unit 1	Unit 2	Unit 1	Unit 2
Location		ESP Outlet	ESP Outlet	FGD Outlet	FGD Outlet
Volumetric flow rate vol.	scfm	777,278	1,352,566	867,848	1,488,608
Volumetric flow rate vol.	acfm	1,130,518	1,957,344	957,174	1,641,826
Mass Flow	lb/h	3,479,114	6,054,144	3,746,438	6,458,834
Temperature	Degree F	335	331	143	143
Mass Flow					
Nitrogen	lb/h	2,336,124	4,063,656	2,371,942	4,126,178
Carbon dioxide	lb/h	614,626	1,072,838	622,052	1,085,802
Oxygen	lb/h	205,550	354,516	213,652	368,656
Moisture	lb/h	309,692	540,334	536,484	874,274
Sulfur dioxide	lb/h	11,382	19,868	568	992
Sulfur trioxide	lb/h	0	0	0	0
Nitrogen oxide	lb/h	0	0	0	0
Nitrogen dioxide	lb/h	1,670	2,778	1,670	2,778
Argon	lb/h	0	0	0	0
Ammonia	lb/h	0	0	0	0
Particulate	lb/h	70	154	70	154
Urea	lb/h				
Total	lb/h	3,479,114	6,054,144	3,746,438	6,458,834

Bowman, Chris

From: Bowman, Chris
Sent: Thursday, April 09, 2009 1:15 PM
To: 'JWaller@babcockpower.com'; cerickson@babcockpower.com; MGialanella@babcockpower.com; mjasinski@babcockpower.com
Cc: Blackwood, Dave
Subject: FW: Low Dust/Tail End SCR

In regards to FGD GGH leakage, see below:

From: Bowman, Chris
Sent: Monday, March 30, 2009 3:43 PM
To: 'MGialanella@babcockpower.com'
Cc: 'bbasile@babcockpower.com'; Blackwood, Dave
Subject: RE: Low Dust/Tail End SCR

Mario,

To clarify our conversation about gas to gas heat exchangers (GGH), it is our understanding that for the tail end SCR arrangements a GGH is needed to heat the WFGD outlet air above the saturation temp to avoid acid mist condensation in the SCR GGH.

Due to SO2 emission limits required, the GGH at the WFGD cannot exceed more than a 2% leakage. If this is cannot be achieved then we would require a “no-leak” type GGH at the FGD, possibly one using a heat transfer fluid in a closed-loop or a direct-fired NG burner. Based on your experience with these projects we will default to your assumption as to which type of GGH would be most economically prudent

The use of steam as a heating source, such as a steam coil, is not an option for this site. Thanks,

Christopher Bowman
Development Engineer
Burns & McDonnell
Direct: 816-333-9400 x5693
Main: 816-333-9400
Fax: 816-333-3690
www.burnsmcd.com
Proud to be one of FORTUNE’s 100 Best Companies To Work For

From: Bowman, Chris
Sent: Monday, March 30, 2009 9:40 AM
To: 'MGialanella@babcockpower.com'
Cc: 'bbasile@babcockpower.com'
Subject: RE: Low Dust/Tail End SCR

Mario,

As mentioned in the phone call today, if you could please provide the information in the following time frame it would be appreciated:

April 10th
Equipment dimensions and layout requirements
Heat exchanger weights

May 1st
Pressure loss for each piece of equipment
Ammonia consumption, slip rates, and natural gas consumption

Thanks,

Christopher Bowman
Development Engineer
cbowman@burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

From: Bowman, Chris
Sent: Friday, March 20, 2009 2:55 PM
To: MGialanella@babcockpower.com
Cc: 'bbasile@babcockpower.com'
Subject: FW: Low Dust/Tail End SCR

The listed SCR COD dates for each unit were incorrect. COD schedule of the low dust or tail end SCR at MRY would be negotiated with vendors to determine the soonest COD date possible.

Have a great weekend,

Christopher Bowman

Development Engineer
Burns & McDonnell Engineering
(816) 333-9400 x5693
cbowman@burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

From: Bowman, Chris
Sent: Thursday, March 19, 2009 9:06 AM
To: MGialanella@babcockpower.com
Cc: barry.basile@babcockpower.com
Subject: RFQ: Low Dust/Tail End SCR

Mario,

As discussed on the phone, Minnkota Power is looking to add an SCR to each existing unit at their Milton R. Young Power Station (MRY). Due to the high sodium content of the coal, we are requesting budgetary equipment quotes of a Low Dust and Tail End SCR arrangement for each unit at MRY. The Low Dust SCR will be located downstream of each units ESP and the Tail End SCR will be located downstream of each units WFGD. The estimated flue gas for each associated option and coal analysis is attached.

General Information:
Unit 1, 257 MWg, cyclone-fired, subcritical, SCR COD December 2010
Unit 2, 477 MWg, cyclone-fired, subcritical, SCR COD December 2011
Fuel: Each unit burns 100% North Dakota Lignite.
Ammonia Reagent: 50% Urea solution
Location: Center, North Dakota – Milton R. Young Station

Each system should be based upon the following components and specifications:

- SCR system w/ gas bypass for maintenance (approx. 12.5% of total gas volume)
- Reactor housing
- Catalyst
- Associated flues and internal flow distribution devices

- Ammonia injection grid
- Hoists and monorails for SCR internal maintenance
- Sonic horns
- Natural gas reheater
- Regenerative gas to gas heat exchanger
- Associated interconnecting piping
- Freight to Center, North Dakota

Provided by others:

- Ductwork to and from SCR
- Structural support steel
- Foundations
- Electrical equipment and controls
- Air compressors
- ID Fans and/or booster fans
- Urea to Ammonia supply system

Please base each systems design assuming guarantees to be provided for NOx reduction as follows:
SCR Inlet NOx: 0.50 lb/MMBtu
Stack Outlet NOx: 0.075 lb/MMBtu
Heat Input (Max / Min):

- Unit 1: 2,995 / 2,744 MMBtu/hr
- Unit 2: 5,158 / 4,885 MMBtu/hr

Information required as soon as possible (estimated):

- Equipment dimensions and layout requirements
- Heat exchanger weights
- Pressure loss for each piece of equipment
- Ammonia consumption, slip rates, and natural gas consumption

We are requesting budgetary pricing of each system by **June 1st** in present day dollars with breakout of the catalyst pricing. Please let us know if you will be able to meet this deadline.

Thank you for your continued assistance and please call if you have any questions.

Christopher Bowman

Development Engineer
Burns & McDonnell Engineering
(816) 333-9400 x5693
cbowman@burnsmcd.com
Proud to be one of FORTUNE's 100 Best Companies To Work For

Please note this effort is currently confidential and should be treated accordingly. Additionally, we do not want any technical papers written and/or published until Burns & McDonnell and Minnkota give written permission.

Bowman, Chris

From: JWaller@babcockpower.com
Sent: Tuesday, April 28, 2009 3:36 PM
To: Bowman, Chris
Cc: Blackwood, Dave; MGialanella@babcockpower.com; mjasinski@babcockpower.com
Subject: RE: Low Dust/Tail End SCR
Attachments: Design Info 4-28-09.xls

Chris,

Attached is the additional information you requested.

Regards,

Jack Waller
Babcock Power Environmental Inc.
(508) 854-3850

RILEYPower
A Babcock Power Inc. Company

Minnkota Power - Milton R. Young Power Station

	Differential Pressure (iwc)	Ammonia (lbs/hr)	Slip (ppm)	Natural Gas (lbs/hr)
Unit 1 Low Dust				
SCR	2.0	500	2.0	1050
GGH (Untreated Gas)	2.3			
GGH (Treated Gas)	2.3			
Unit 2 Low Dust				
SCR	2.0	860	2.0	1780
GGH (Untreated Gas)	1.74			
GGH (Treated Gas)	1.74			
Unit 1 Tail End				
FGD - GGH (Untreated Gas)	2.7			
FGD - GGH (Treated Gas)	2.7			
SCR	2.0	500	2.0	1150
SCR - GGH (Untreated Gas)	2.67			
SCR - GGH (Treated Gas)	2.67			
Unit 2 Tail End				
FGD - GGH (Untreated Gas)	1.87			
FGD - GGH (Treated Gas)	1.87			
SCR	2.0	860	2.0	2120
SCR - GGH (Untreated Gas)	1.98			
SCR - GGH (Treated Gas)	1.98			

From: Wayne Jones [mailto:WSJ@topsoe.com]
Sent: Monday, August 03, 2009 8:24 AM
To: Blakley, Robert
Cc: TNW@topsoe.com
Subject: RE: FW: Comments to SCR Technology at MRYS Units 1&2

Bob,

It was nice talking with you this morning. We will plan on meeting with you and the folks from Minnkota and the University of North Dakota on Monday afternoon August 10th in our office's in Houston, Texas. Our address is: 17629 El Camino Real, Houston, TX 77058, Suite 300. Please let me know what time we should expect you as you are able to firm thing up.

Regards,
Wayne

Wayne S. Jones
Sales Manager, Power Generation
Haldor Topsoe, Inc.
281-228-5136 (office)
281-228-5129 (fax)
281-684-8811 (cell)
wsj@topsoe.com
www.HaldorTopsoe.com

From: Blakley, Robert
Sent: Monday, August 03, 2009 5:18 PM
To: Wayne Jones
Cc: TNW@topsoe.com; Bryant, Ronald; 51684
Subject: RE: FW: Comments to SCR Technology at MRYS Units 1&2

Wayne -

Thank you for your willingness to meet with Minnkota, Burns & McDonnell, and University of North Dakota on Monday afternoon, August 10th.

The purpose of this visit is to introduce the members of the project team, and to discuss Haldor Topsoe's experience with SCR catalyst and how it may relate to this application. One of our objectives for this project is to establish expected catalyst volumes and deactivation rates for exposure to flue gases produced by cyclone boilers firing North Dakota lignite at Milton R. Young Station as part of a cost study for low dust and tail end SCR technologies.

The current plans for the trip and visit are as follows:

We will fly on Minnkota's turboprop aircraft departing from near Kansas City, Missouri in the morning, arriving around noon at the Hobby airport (alternate: Ellington field, which is closer to HT's office).

We expect to arrive at Haldor Topsoe's office shortly after 1 pm, allowing for travel from the airport and a quick lunch on the way. We will confirm the estimated arrival time prior to departure.

The meeting is anticipated to take approximately 2 hours, so we expect to depart between 3:00 and 3:30 pm to return to the airport. We will fly back to Kansas City late Monday afternoon.

We currently expect 7 people to visit and participate in this discussion:
> Ron Bryant, Burns & McDonnell project manager for Minnkota air pollution control projects
> Carl Weilert, Burns & McDonnell principal engineer for powerplant air pollution control projects
> Robert Blakley, Burns & McDonnell project engineer for Minnkota's NOx reduction program
> Luther Kvernen, Minnkota Vice President of Generation, Grand Forks, North Dakota headquarters
> John Graves, Minnkota Environmental Manager, Grand Forks, North Dakota headquarters
> Andy Freidt, Minnkota Permit and Compliance Engineer, Milton R. Young Station, Center, North Dakota
> Steven Benson, PhD, Professor, Department of Chemical Engineering at University of North Dakota, Grand Forks, ND, and President, Microbeam Technologies, Inc.

You advised this morning (Monday, 8/3) that you will be out of the office until mid-day Thursday, 8/6. We will confirm any updates in schedules and arrangements Thursday afternoon or Friday morning.

If you have any questions, please advise.

Thanks,

Bob Blakley

From: Wayne Jones [mailto:WSJ@topsoe.com]
Sent: Monday, August 03, 2009 8:24 AM
To: Blakley, Robert
Cc: TNW@topsoe.com
Subject: RE: FW: Comments to SCR Technology at MRYS Units 1&2

Bob,

It was nice talking with you this morning. We will plan on meeting with you and the folks from Minnkota and the University of North Dakota on Monday afternoon August 10th in our office's in Houston, Texas. Our address is: 17629 El Camino Real, Houston, TX 77058, Suite 300. Please let me know what time we should expect you as you are able to firm thing up.

Regards,
Wayne

Wayne S. Jones
Sales Manager, Power Generation
Haldor Topsoe, Inc.
281-228-5136 (office)
281-228-5129 (fax)
281-684-8811 (cell)
wsj@topsoe.com
www.HaldorTopsoe.com

From: Bryant, Ronald
Sent: Wednesday, August 05, 2009 1:11 PM
To: 'Wayne Jones'
Cc: 51684; 'TNW@topsoe.com'; Blakley, Robert
Subject: Agenda

Wayne

Attached is a draft agenda from Minnkota Power for our meeting next Monday. Let us know if you have any comments.

Thanks
Ron Bryant

From: Blakley, Robert
Sent: Wednesday, August 05, 2009 1:05 PM
To: Wayne Jones
Cc: 51684; Bryant, Ronald; TNW@topsoe.com
Subject: RE: FW: Comments to SCR Technology at MRYS Units 1&2

Wayne -

Does Haldor Topsoe have a digital projector that Minnkota can hook up to a laptop PC to use during the discussion?

If not, we can bring one.

Bob Blakley

From: Blakley, Robert
Sent: Wednesday, August 05, 2009 6:53 AM
To: 'Wayne Jones'
Cc: 51684; Bryant, Ronald; TNW@topsoe.com
Subject: RE: FW: Comments to SCR Technology at MRYS Units 1&2

Thanks, Wayne. We'll check on the rental car availability. Minnkota's pilot is pretty good at finding out those details.

Bob Blakley

From: Wayne Jones [mailto:WSJ@topsoe.com]
Sent: Tuesday, August 04, 2009 6:18 PM
To: Blakley, Robert
Cc: 51684; Bryant, Ronald; TNW@topsoe.com
Subject: RE: FW: Comments to SCR Technology at MRYS Units 1&2

Bob,

Sounds good. Please confirm that rental cars are easily available at Ellington (Southwest Svs.). I will let you know in a day or two on a restaurant where we can meet. Several good locations are within 10 minutes of Ellington Field.

Thanks,
Wayne

Wayne S. Jones
Sales Manager, Power Generation
Haldor Topsoe, Inc.
281-228-5136 (office)
281-228-5129 (fax)
281-684-8811 (cell)
wsj@topsoe.com
www.HaldorTopsoe.com

"Blakley, Robert"
<rblakley@burnsmcd.com>

08/04/2009 04:40 PM

To "Wayne Jones" <WSJ@topsoe.com>

cc <TNW@topsoe.com>, "51684" <51684@burnsmcd.com>, "Bryant, Ronald" <rbryant@burnsmcd.com>

Subject RE: FW: Comments to SCR Technology at MRYS Units 1&2

Wayne -

Minnkota, BMcD, and UND accept your lunch invitation and suggestion for the local airport.

Minnkota's pilot will plan on flying and landing at Ellington field, Southwest Airport Services. Minnkota will arrange for local transportation at Ellington field.

Just let me know where you'll be meeting us for lunch, and we will plan on arriving there shortly after noon on Monday, August 10th.

We will advise on the agenda in the next day or two.

Bob Blakley

From: Wayne Jones [mailto:WSJ@topsoe.com]
Sent: Monday, August 03, 2009 10:12 PM
To: Blakley, Robert
Cc: TNW@topsoe.com
Subject: RE: FW: Comments to SCR Technology at MRYS Units 1&2

Bob,

Ellington Field is closer, about 10-15 minutes away. Since you are flying a private plane you can probably use Southwest

Services who is the main flying service at Ellington.

Also Nate and I would like to take y'all to lunch if possible. We can talk later in the week and work out the details.

Thanks,
Wayne

Wayne S. Jones
Sales Manager, Power Generation
Haldor Topsoe, Inc.
281-228-5136 (office)
281-228-5129 (fax)
281-684-8811 (cell)
wsj@topsoe.com
www.HaldorTopsoe.com

"Blakley, Robert" <rblakley@burnsmcd.com>

08/03/2009 05:18 PM

To "Wayne Jones" <WSJ@topsoe.com>
cc <TNW@topsoe.com>, "Bryant, Ronald" <rbryant@burnsmcd.com>, "51684" <51684@burnsmcd.com>

Subject RE: FW: Comments to SCR Technology at MRYS Units 1&2

Wayne -

Thank you for your willingness to meet with Minnkota, Burns & McDonnell, and University of North Dakota on Monday afternoon, August 10th.

The purpose of this visit is to introduce the members of the project team, and to discuss Haldor Topsoe's experience with SCR catalyst and how it may relate to this application. One of our objectives for this project is to establish expected catalyst volumes and deactivation rates for exposure to flue gases produced by cyclone boilers firing North Dakota lignite at Milton R. Young Station as part of a cost study for low dust and tail end SCR technologies.

The current plans for the trip and visit are as follows:

We will fly on Minnkota's turboprop aircraft departing from near Kansas City, Missouri in the morning, arriving around noon at the Hobby airport (alternate: Ellington field, which is closer to HT's office).

We expect to arrive at Haldor Topsoe's office shortly after 1 pm, allowing for travel from the airport and a quick lunch on the way. We will confirm the estimated arrival time prior to departure.

The meeting is anticipated to take approximately 2 hours, so we expect to depart between 3:00 and 3:30 pm to return to the airport. We will fly back to Kansas City late Monday afternoon.

We currently expect 7 people to visit and participate in this discussion:

> Ron Bryant, Burns & McDonnell project manager for Minnkota air pollution control projects
> Carl Weilert, Burns & McDonnell principal engineer for powerplant air pollution control projects
> Robert Blakley, Burns & McDonnell project engineer for Minnkota's NOx reduction program
> Luther Kvernen, Minnkota Vice President of Generation, Grand Forks, North Dakota headquarters
> John Graves, Minnkota Environmental Manager, Grand Forks, North Dakota headquarters
> Andy Freidt, Minnkota Permit and Compliance Engineer, Milton R. Young Station, Center, North Dakota
> Steven Benson, PhD, Professor, Department of Chemical Engineering at University of North Dakota, Grand Forks, ND, and President, Microbeam Technologies, Inc.

You advised this morning (Monday, 8/3) that you will be out of the office until mid-day Thursday, 8/6. We will confirm any updates in schedules and arrangements Thursday afternoon or Friday morning.

If you have any questions, please advise.

Thanks,

Bob Blakley

From: Wayne Jones [mailto:WSJ@topsoe.com]
Sent: Monday, August 03, 2009 8:24 AM
To: Blakley, Robert
Cc: TNW@topsoe.com
Subject: RE: FW: Comments to SCR Technology at MRYS Units 1&2

Bob,

It was nice talking with you this morning. We will plan on meeting with you and the folks from Minnkota and the University of North Dakota on Monday afternoon August 10th in our office's in Houston, Texas. Our address is: 17629 El Camino Real, Houston, TX 77058, Suite 300. Please let me know what time we should expect you as you are able to firm thing up.

Regards,
Wayne

Wayne S. Jones
Sales Manager, Power Generation
Haldor Topsoe, Inc.
281-228-5136 (office)
281-228-5129 (fax)
281-684-8811 (cell)
wsj@topsoe.com
www.HaldorTopsoe.com

DRAFT #2 – HALDOR TOPSOE
MINNKOTA – MRY STATION SCR COST STUDY MEETING

Monday, August 10, 2009
1:00 PM
Meeting Location: Haldor Topsoe, Inc., Houston, Texas

Meeting Participants:

Haldor Topsoe, Inc.

- Wayne Jones, Sales Manager, Power Generation (Houston)
- Nathan White, Senior Account Executive (Houston)
-

Minnkota Power Cooperative, Inc.

- Luther Kvernen, Vice President - Generation (Grand Forks Headquarters)
- John Graves, Environmental Manager (Grand Forks Headquarters)
- Andy Freidt, Permit and Compliance Engineer (MRY Station)

University of North Dakota and Microbeam Technologies

- Steven Benson, PhD, Professor, Department of Chemical Engineering at University of North Dakota and President, Microbeam Technologies, Inc

Burns & McDonnell

- Ron Bryant, Burns & McDonnell project manager for Minnkota air pollution control projects
- Carl Weilert, Burns & McDonnell principal engineer for powerplant air pollution control projects
- Robert Blakley, Burns & McDonnell project engineer for Minnkota's NOx reduction program

Meeting Purpose:

1. To develop a common understanding of the purpose, unique challenges and status of Minnkota's cost study for low dust and tail end SCR technologies.
2. Discuss Haldor Topsoe's experience with SCR catalyst and how it may relate to the application of high sodium and potassium aerosols associated with the combustion of ND lignite in cyclone fired boilers.

AGENDA

1. Introductions

2. Review Meeting Purpose and Agenda

3. Minnkota/MRY Station Background – Luther Kvernen (10 minutes)

- Organization
- SCR cost study

4. ND Lignite (Center Mine) Characteristics – Steve Benson (10 minutes)

5. SCR cost study – Burns & McDonnell (designate) (10 minutes)

- Impact of catalyst volumes and deactivation rates
    - Input requirements to provide reasonable cost estimates

6. Haldor Topsoe Background – _____ (10 minutes)

- Organization
- Experience with SCR catalyst for this type of application

7. Identify specific questions/concerns -- All

8. Exploration of opportunities – All

9. Action items

10. Other

From: Nate White [mailto:TNW@topsoe.com]
Sent: Wednesday, August 05, 2009 8:38 PM
To: Bryant, Ronald
Cc: 51684; Blakley, Robert; Wayne Jones
Subject: Re: Agenda

Hello Ron,

One change to your agenda. I am no longer a Senior Account Executive. I am Director, Business Development. We re-organized the SCR/DeNOx Catalyst & Technology side of HTI back in February, 2009. We will explain our new organization and responsibilities to you when we see you Monday.

Best regards,
Nathan White
Director, Business Development
SCR/DeNOx Catalyst & Technology
Fort Mill, SC Office - (803) 835-0571
Houston, TX Office - (281) 228-5127
Cell - (281) 684-8809
tnw@topsoe.com

"Bryant, Ronald" <rbryant@burnsmcd.com>

08/05/2009 01:11 PM

To "Wayne Jones" <WSJ@topsoe.com>

cc "51684" <51684@burnsmcd.com>, <TNW@topsoe.com>, "Blakley, Robert" <rblakley@burnsmcd.com>

Subject Agenda

Wayne

Attached is a draft agenda from Minnkota Power for our meeting next Monday. Let us know if you have any comments.

Thanks
Ron Bryant

DRAFT #2 – HALDOR TOPSOE
MINNKOTA – MRY STATION SCR COST STUDY MEETING

Monday, August 10, 2009
1:00 PM
Meeting Location: Haldor Topsoe, Inc., Houston, Texas

Meeting Participants:

Haldor Topsoe, Inc.

- Wayne Jones, Sales Manager, Power Generation (Houston)
- Nathan White, Senior Account Executive (Houston)
-

Minnkota Power Cooperative, Inc.

- Luther Kvernen, Vice President - Generation (Grand Forks Headquarters)
- John Graves, Environmental Manager (Grand Forks Headquarters)
- Andy Freidt, Permit and Compliance Engineer (MRY Station)

University of North Dakota and Microbeam Technologies

- Steven Benson, PhD, Professor, Department of Chemical Engineering at University of North Dakota and President, Microbeam Technologies, Inc

Burns & McDonnell

- Ron Bryant, Burns & McDonnell project manager for Minnkota air pollution control projects
- Carl Weilert, Burns & McDonnell principal engineer for powerplant air pollution control projects
- Robert Blakley, Burns & McDonnell project engineer for Minnkota's NOx reduction program

Meeting Purpose:

1. To develop a common understanding of the purpose, unique challenges and status of Minnkota's cost study for low dust and tail end SCR technologies.
2. Discuss Haldor Topsoe's experience with SCR catalyst and how it may relate to the application of high sodium and potassium aerosols associated with the combustion of ND lignite in cyclone fired boilers.

AGENDA

1. Introductions

2. Review Meeting Purpose and Agenda

3. Minnkota/MRY Station Background – Luther Kvernen (10 minutes)

- Organization
- SCR cost study

4. ND Lignite (Center Mine) Characteristics – Steve Benson (10 minutes)

5. SCR cost study – Burns & McDonnell (designate) (10 minutes)

- Impact of catalyst volumes and deactivation rates
    - Input requirements to provide reasonable cost estimates

6. Haldor Topsoe Background – _____ (10 minutes)

- Organization
- Experience with SCR catalyst for this type of application

7. Identify specific questions/concerns -- All

8. Exploration of opportunities – All

9. Action items

10. Other

Bryant, Ronald

From: Bryant, Ronald
Sent: Friday, August 07, 2009 2:56 PM
To: 'Noel Rosha'
Cc: 'James Ferrigan'; Blakley, Robert; 'Greg Holscher'; 51684
Subject: Minnkota PFDs and Mass Balances
Attachments: 10Mar09_MRY2LowDust_PFD_Rev0_natgas.pdf; 9Mar09_MRY2TailEnd_Mass Balance_Rev0_natgas.pdf; 9Mar09_MRY2TailEnd_PFD_Rev0_natgas.pdf; 10Mar09_Hypothetical SCR_Reactor Arrangement_Summary.pdf; 10Mar09_MRY1LowDust_MassBalance_Rev0_natgas.pdf; 10Mar09_MRY1LowDust_PFD_Rev0_natgas.pdf; 10Mar09_MRY1TailEnd_MassBalance_Rev0_natgas.pdf; 10Mar09_MRY1TailEnd_PFD_Rev0_natgas.pdf; 10Mar09_MRY2LowDust_Mass BalanceRev0_natgas.pdf

Attachments this time.

From: Bryant, Ronald
Sent: Friday, August 07, 2009 2:55 PM
To: Noel Rosha
Cc: James Ferrigan; Blakley, Robert; Greg Holscher; 51684
Subject:

Noel

Attached are preliminary PFDs and mass balances requested for the low dust and tail end SCRs at the Milton R Young Station.

Ron

Burns & McDonnell

Client: **Confidential**

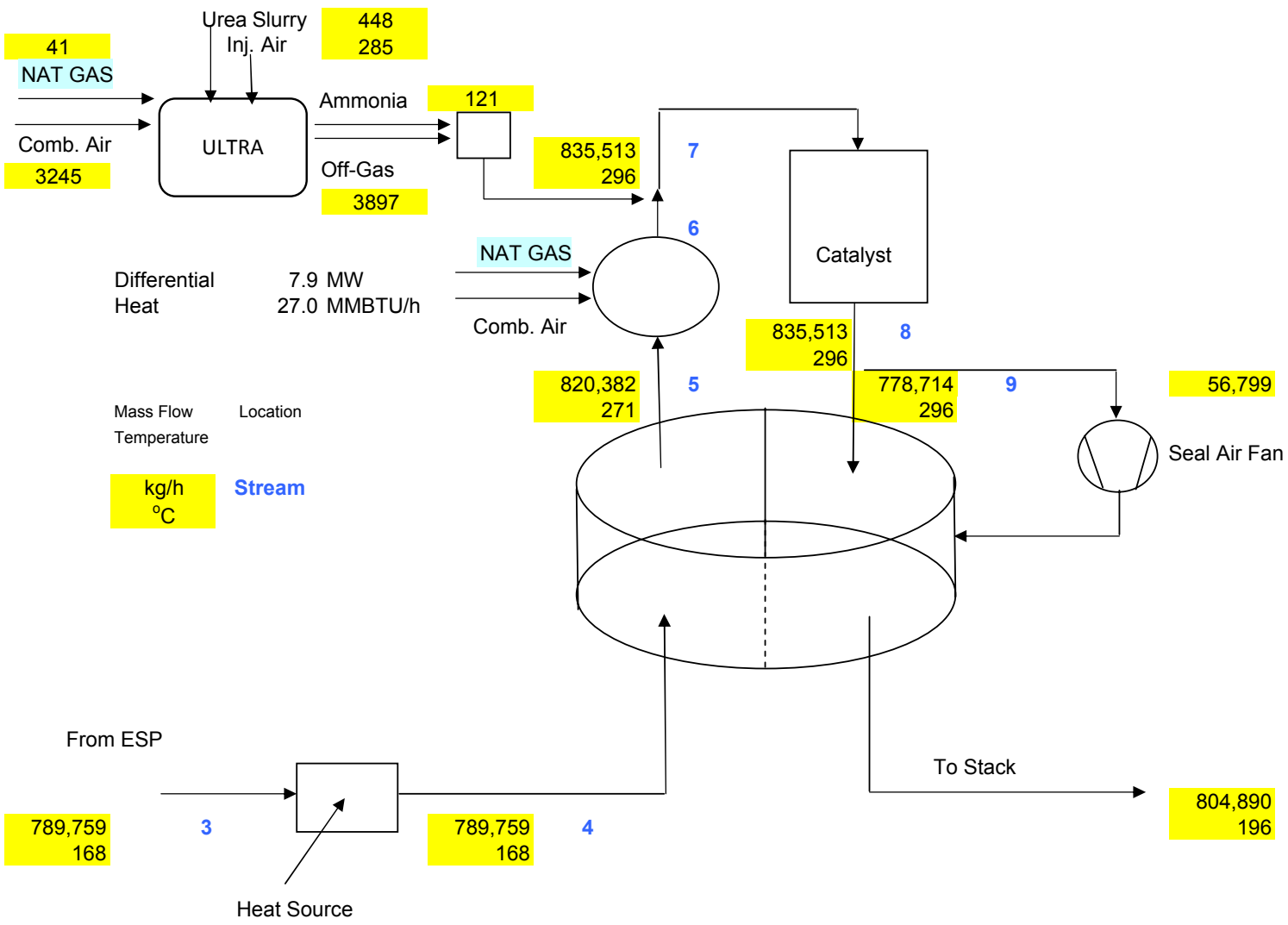
Subject: **Hypothetical SCR Reactor Arrangements**

	Unit 1	**Unit 1**	**Unit 2**	**Unit 2**
SCR	**Low Dust**	**Tail End**	**Low Dust**	**Tail End**
Flue Gas Flow (lb/hr)	1,815,800 Per reactor	1,993,400 Per reactor	3,159,000 Per reactor	3,369,300 Per reactor
Nm^3/hr	643,500	731,800	1,119,560	1,231,630
Flue Gas Temperature	630F	600F	630	600
# Reactors	2	2	2	2
Reactor				
# modules	45 (5 * 9)	45 (5 * 9)	84 (7 * 12)	77 (7 * 11)
Dimensions per reactor (approx)	10,085 mm * 9,210 mm	10,085 mm * 9,210 mm	14,025 mm * 12,200 mm	14,025 mm * 11,200 mm
	33’ * 30’	33’ * 30’	46’ * 40’	46’ * 37’
Module Layers	2 + 1	2 + 1	2 + 1	2 + 1
Initial Volume (m^3)	132	160	249	249

MRY 1		Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21		
		ESP Outlet	ESP Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air		
Volumetric flow rate vol.	Nm^3/h		616,442	616,442	640,345	649,337	652,592	652,674	608,347	619,933	619,933	644	8,334	158	3,097	44,359	8,979		52	2,521		221	Nm^3/h	Volumetric flow rate vol.
Volumetric flow rate vol.	scfm		388,639	388,639	403,709	409,378	411,430	411,482	383,536	390,840	390,840	406	5,254	100	1,953	27,966	5,661		33	1,589		140	scfm	Volumetric flow rate vol.
Volumetric flow rate vol.	acfm		565,259	565,259	731,859	777,489	783,269	789,069	736,373	624,992	624,992												acfm	Volumetric flow rate vol.
Mass Flow	kg/h		789,759	789,759	820,382	831,496	835,513	835,513	778,714	804,890	804,890	502	10,611	121	3,897	56,799	11,114	121	41	3,245	448	285	kg/h	Mass Flow
Mass Flow	lb/hour		1,739,556	1,739,556	1,807,009	1,831,488	1,840,338	1,840,338	1,715,229	1,772,885	1,772,885	1,107	23,373	265	8,584	125,109	24,479	265	90	7,148	986	628	lb/hour	Mass Flow
Temperature	Degree F	335	335	335	520	564	564	564	564	384	384												Degree F	Temperature
Temperature	Degree C		168	168	271	296	296	296	296	196	196												Degree C	Temperature
Pressure	iwg		14.5	13.5	10	9	8	5	4.5	0	0													Pressure
Composition																								Composition
Nitrogen	Vol-parts		0.6881	0.6881	0.6881	0.6893	0.6890	0.6893	0.6893	0.6880	0.6880		0.7900		0.6810		0.7705	0.2999		0.7900		0.7900	Vol-parts	Nitrogen
Carbon di oxide	Vol-parts		0.1152	0.1152	0.1152	0.1146	0.1143	0.1142	0.1142	0.1148	0.1148				0.0458		0.0703						Vol-parts	Carbon di oxide
Oxygen	Vol-parts		0.0530	0.0530	0.0530	0.0525	0.0529	0.0528	0.0528	0.0532	0.0532		0.2100		0.1432		0.0147			0.2100		0.2100	Vol-parts	Oxygen
Moisture	Vol-parts		0.1419	0.1419	0.1419	0.1419	0.1418	0.1421	0.1421	0.1424	0.1424				0.1220		0.1445	0.7001					Vol-parts	Moisture
Sulfur di oxide	Vol-parts		0.0015	0.0015	0.0015	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014						0.0000						Vol-parts	Sulfur di oxide
Sulfur tri oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Sulfur trioxide
Nitrogen oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen oxide
Nitrogen di oxide	Vol-parts		0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen di oxide
Argon	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				0.0081		0.0000						Vol-parts	Argon
Ammonia	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Ammonia
Total			1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000		1.0000		1.0000		1.0000	1.0000		1.0000		1.0000	Vol-parts	Total
Volumetric Flow			0																					Volumetric Flow
Nitrogen	Nm^3/h		424,187	424,187	440,644	447,558	449,667	449,905	419,350	426,532	426,532		6,584		2,109	30,520	6,918	39		1,991		175	Nm^3/h	Nitrogen
Carbon di oxide	Nm^3/h		71,044	71,044	73,788	74,419	74,561	74,561	69,497	71,186	71,186				142	5,094	631						Nm^3/h	Carbon di oxide
Oxygen	Nm^3/h		32,677	32,677	33,950	34,082	34,525	34,446	32,106	32,963	32,963		1,750		444	2,359	132			529		47	Nm^3/h	Oxygen
Moisture	Nm^3/h		87,446	87,446	90,856	92,153	92,531	92,769	86,468	88,294	88,294				378	6,318	1,298	90					Nm^3/h	Moisture
Sulfur di oxide	Nm^3/h		904	904	938	938	938	929	866	895	895				0	64	0						Nm^3/h	Sulfur di oxide
Sulfur tri oxide	Nm^3/h		0	0	0	0	0	9	9	9	9				0	1	0						Nm3/h	Sulfur trioxide
Nitrogen oxide	Nm^3/h		0	0	0	0	0	0	0	0	0				0	0	0						Nm3/h	Nitrogen oxide
Nitrogen dioxide	Nm^3/h		185	185	184	186	186	27	25	28	28				0	2	0						Nm^3/h	Nitrogen di oxide
Argon	Nm^3/h		0	0	1	1	26	26	24	25	25				25	2	0						Nm3/h	Argon
Ammonia	Nm^3/h		0	0	0	0	158	2	2	2	2				0	0	0						Nm3/h	Ammonia
Total	Nm^3/h		616,442	616,442	640,362	649,337	652,592	652,674	608,347	619,933	619,933		8,334		3,097	44,359	8,979	129		2,521		221	Nm^3/h	Total
Mass Flow																								Mass Flow
Nitrogen	kg/h	1,060,600	530,300	530,300	550,874	559,517	562,154	562,452	524,253	533,231	533,231		8,231		2,637	38,155	8,643	48		2,489		219	kg/h	Nitrogen
Carbon di oxide	kg/h	279,040	139,520	139,520	144,909	146,148	146,427	146,427	136,482	139,799	139,799				279	10,003	1,239						kg/h	Carbon di oxide
Oxygen	kg/h	93,320	46,660	46,660	48,478	48,666	49,300	49,186	45,846	47,069	47,069		2,499		633	3,368	189			756		66	kg/h	Oxygen
Moisture	kg/h	140,600	70,300	70,300	73,042	74,084	74,388	74,579	69,514	70,982	70,982				304	5,079	1,042	72			224		kg/h	Moisture
Sulfur di oxide	kg/h	5,167	2,584	2,584	2,682	2,682	2,682	2,656	2,476	2,558	2,558				0	183							kg/h	Sulfur di oxide
Sulfur tri oxide	kg/h		0	0	2	2	2	34	32	32	32				0	2							kg/h	Sulfur trioxide
Nitrogen oxide	kg/h		0	0	0	0	0	0	0	0	0				0	0							kg/h	Nitrogen oxide
Nitrogen di oxide	kg/h	758	379	379	378	381	381	56	52	57	57				0	4	4						kg/h	Nitrogen di oxide
Argon	kg/h		0	0	2	2	47	47	44	44	44				44	3							kg/h	Argon
Ammonia	kg/h		0	0	0	0	121	1	1	1	1			121	0	0							kg/h	Ammonia
Particulate	kg/h	32	16	16	17	17	17	17	15	16	16				0	1							kg/h	Particulate
Urea	kg/h																				224		kg/h	Urea
Total	kg/h	1,579,517	789,759	789,759	820,382	831,499	835,517	835,454	778,714	793,790	793,790		10,730	121	3,897	56,799	11,117	121		3,245	448	285	kg/h	Total
Nitrogen	lb/h		1,168,062	1,168,062	1,213,379	1,232,417	1,238,225	1,238,880	1,154,742	1,174,518	1,174,518		18,130	0	5,808	84,042	19,038	106		5,483		482	lb/h	Nitrogen
Carbon di oxide	lb/h		307,313	307,313	319,182	321,912	322,526	322,526	300,622	307,927	307,927			0	614	22,034	2,730	0					lb/h	Carbon di oxide
Oxygen	lb/h		102,775	102,775	106,779	107,195	108,590	108,340	100,982	103,677	103,677		5,505	0	1,395	7,419	415	0		1,665		146	lb/h	Oxygen
Moisture	lb/h		154,846	154,846	160,885	163,181	163,850	164,272	153,115	156,348	156,348			0	669	11,187	2,296	159			493		lb/h	Moisture
Sulfur di oxide	lb/h		5,691	5,691	5,907	5,907	5,907	5,850	5,453	5,634	5,634			0	0	403		0					lb/h	Sulfur di oxide
Sulfur tri oxide	lb/h		0	0	4	4	4	75	70	71	71				0	5							lb/h	Sulfur trioxide
Nitrogen oxide	lb/h		0	0	0	0	0	0	0	0	0				0	0							lb/h	Nitrogen oxide
Nitrogen di oxide	lb/h		835	835	832	840	840	122	114	126	125			0	0	9	8	0					lb/h	Nitrogen di oxide
Argon	lb/h		0	0	5	5	103	103	96	98	98				98	7							lb/h	Argon
Ammonia	lb/h		0	0	0	0	266	3	3	3	3				0	0							lb/h	Ammonia
Particulate	lb/h		35	35	37	37	37	37		35	35				0	3							lb/h	Particulate
Urea	lb/h																				493		lb/h	Urea
Total	lb/h		1,739,556	1,739,556	1,807,009	1,831,497	1,840,346	1,840,207	1,715,195	1,748,437	1,748,436		23,635	0	8,584	125,109	24,487	265		7,148	986	628	lb/h	Total
Composition																								Composition
Nitrogen	Mass-parts		0.671	0.671	0.671	0.673	0.673	0.673	0.673	0.672	0.672		0.767		0.677	0.672	0.777			0.767		0.767	Mass-parts	Nitrogen
Carbon di oxide	Mass-parts		0.177	0.177	0.177	0.176	0.175	0.175	0.175	0.176	0.176		0.000		0.072	0.176	0.111						Mass-parts	Carbon di oxide
Oxygen	Mass-parts		0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059		0.233		0.163	0.059	0.017			0.233		0.233	Mass-parts	Oxygen
Moisture	Mass-parts		0.089	0.089	0.089	0.089	0.089	0.089	0.089	0.089	0.089		0.000		0.078	0.089	0.094				0.5		Mass-parts	Moisture
Sulfur di oxide	Mass-parts		0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003		0.000		0.000	0.003	0.000						Mass-parts	Sulfur di oxide
Sulfur tri oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Sulfur trioxide
Nitrogen oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen oxide
Nitrogen di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen di oxide
Argon	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.011	0.000	0.000						Mass-parts	Argon
Ammonia	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Ammonia
Particulate	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Particulate
Urea	Mass-parts																				0.5		Mass-parts	Urea
Total	Mass-parts		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000		1.000	0.000	0.989	1.000	1.000	0.000		1.000	1.000	1.000	Mass-parts	Total
Density	kg/Nm^3		1.281	1.281	1.281	1.281	1.280	1.280	1.280	1.280	1.280													
Cp	kJ/kgK		1.104654151	1.1046542	1.1349059	1.142477377	1.14247738	1.142477377	1.142477377	1.11237214	1.11237214												kJ/kgK	Cp
Heat Content	MW		40.793	40.793	70.142	78.046	78.423	78.423	73.092	48.631	48.631	7.283							0.592				MW	Heat Content
	MMBTU/hr		139.227	139.227	239.394	266.372	267.659	267.659	249.463	165.977	165.977	24.858							2.022					
NO_2	lbs/hour		834.8018	834.8018	831.9623	840.1753	840.1753	122.3223	114.0148	126.4155	125.2203					9.0							lbs/hour	NO_2
NO_2	kg/h		379.0000	379.0000	377.7109	381.4396	381.4396	55.5343	51.7627	57.3926	56.8500					4.1							kg/h	NO_2
NO_2	Nm^3 / hour		184.6	184.6	184.0	185.8	185.8	27.1	25.2	28.0	27.7					2.0								
NO + NO_2 @ actual O_2	PPM		299.5	299.5	287.4	286.2	284.8	41.5	41.5	45.1	44.7					44.7								
NO + NO_2 @ 3 % O_2	PPM		343.4	343.4	329.5	327.0	326.3	47.5	47.5	51.8	51.3													
						NO2 Balance Check																		
Eta NOx		0.850	0.8500			kg/h	lbs/hr																	

MRY 1	Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21
	ESP Outlet	ESP Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air
Eta NOx reactor		0.8544			0.0	0															

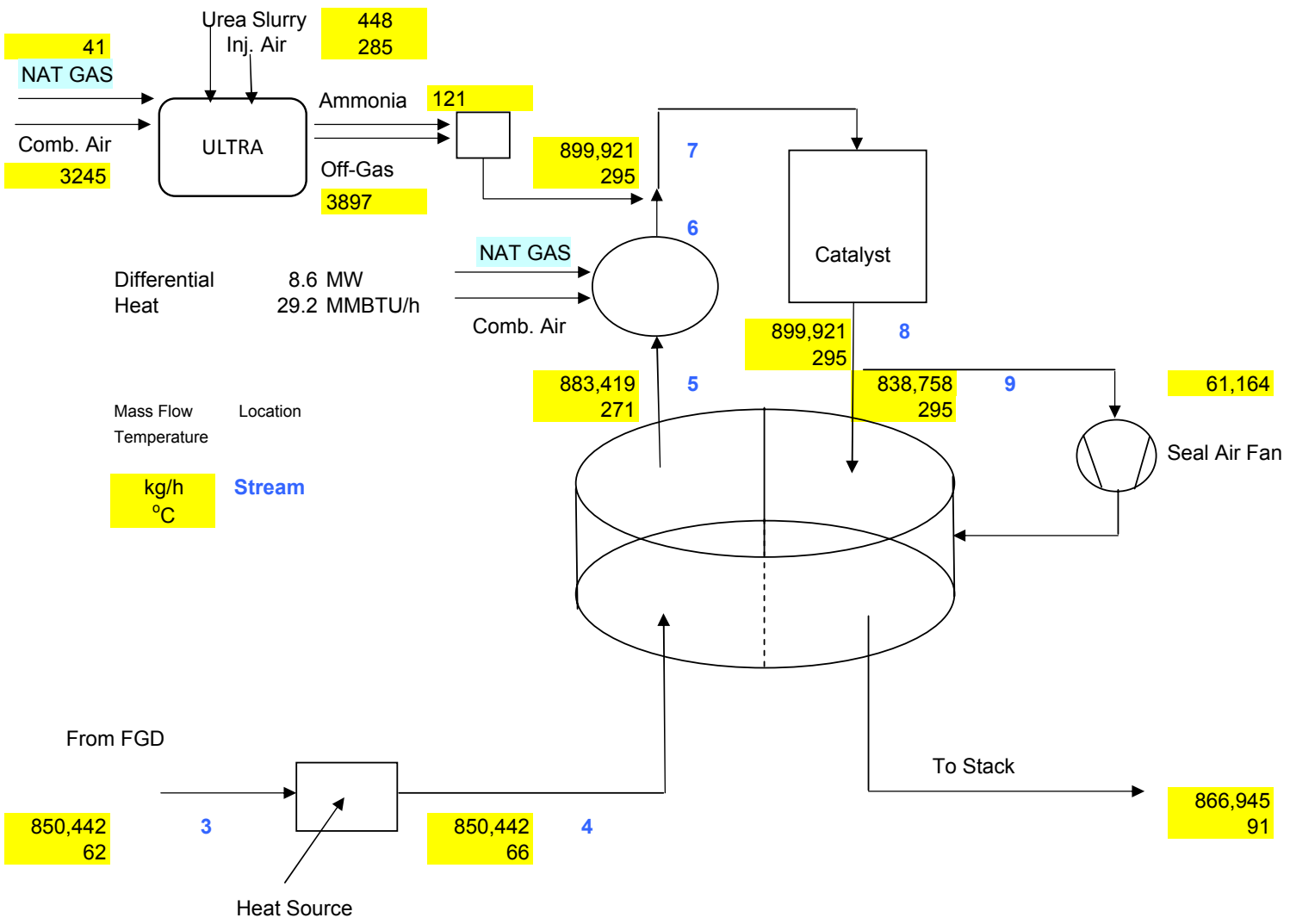
MRY 1 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



MRY 1		Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21		
		FGD Outlet	FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air		
Volumetric flow rate vol.	Nm^3/h		688,272	688,272	714,960	725,054	728,310	728,392	678,935	691,763	691,763	724	9,363	158	3,097	49,517	10,087		52	2,521		221	Nm^3/h	Volumetric flow rate vol.
Volumetric flow rate vol.	scfm		433,924	433,924	450,750	457,114	459,167	459,218	428,038	436,126	436,126	456	5,903	100	1,953	31,218	6,359		33	1,589		140	scfm	Volumetric flow rate vol.
Volumetric flow rate vol.	acfm		478,587	478,587	817,138	866,311	872,297	878,746	820,075	541,960	541,960												acfm	Volumetric flow rate vol.
Mass Flow	kg/h		850,442	850,442	883,419	895,904	899,921	899,921	838,758	866,945	866,945	564	11,921	121	3,897	61,164	12,485	121	41	3,245	448	285	kg/h	Mass Flow
Mass Flow	lb/hour		1,873,220	1,873,220	1,945,856	1,973,356	1,982,206	1,982,206	1,847,484	1,909,570	1,909,570	1,243	26,257	266	8,584	134,722	27,500	266	90	7,148	986	628	lb/hour	Mass Flow
Temperature	Degree F	143	143	150	520	562	562	562	562	196	196												Degree F	Temperature
Temperature	Degree C		62	66	271	295	295	295	295	91	91												Degree C	Temperature
Pressure	iwg		14.5	13.5	10	9	8	5	4.5	0	0													Pressure
Composition																								Composition
Nitrogen	Vol-parts		0.6258	0.6258	0.6258	0.6278	0.6279	0.6281	0.6281	0.6260	0.6260		0.7900		0.6810		0.7705	0.2999		0.7900		0.7900	Vol-parts	Nitrogen
Carbon di oxide	Vol-parts		0.1045	0.1045	0.1045	0.1040	0.1037	0.1037	0.1037	0.1041	0.1041				0.0458		0.0703						Vol-parts	Carbon di oxide
Oxygen	Vol-parts		0.0493	0.0493	0.0494	0.0489	0.0493	0.0491	0.0491	0.0495	0.0495		0.2100		0.1432		0.0147			0.2100		0.2100	Vol-parts	Oxygen
Moisture	Vol-parts		0.2201	0.2201	0.2201	0.2190	0.2186	0.2189	0.2189	0.2202	0.2202				0.1220		0.1445	0.7001					Vol-parts	Moisture
Sulfur di oxide	Vol-parts		0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001						0.0000						Vol-parts	Sulfur di oxide
Sulfur tri oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Sulfur trioxide
Nitrogen oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen oxide
Nitrogen di oxide	Vol-parts		0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen di oxide
Argon	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				0.0081		0.0000						Vol-parts	Argon
Ammonia	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Ammonia
Total			1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000		1.0000		1.0000		1.0000	1.0000		1.0000		1.0000	Vol-parts	Total
Volumetric Flow			0																					Volumetric Flow
Nitrogen	Nm^3/h		430,691	430,691	447,407	455,173	457,283	457,521	426,456	433,036	433,036		7,397		2,109	30,997	7,771	39		1,991		175	Nm^3/h	Nitrogen
Carbon di oxide	Nm^3/h		71,902	71,902	74,681	75,390	75,532	75,532	70,403	72,044	72,044				142	5,157	709						Nm^3/h	Carbon di oxide
Oxygen	Nm^3/h		33,964	33,964	35,288	35,436	35,880	35,800	33,369	34,251	34,251		1,966		444	2,452	148			529		47	Nm^3/h	Oxygen
Moisture	Nm^3/h		151,484	151,484	157,364	158,821	159,199	159,437	148,612	152,332	152,332				378	10,904	1,458	90					Nm^3/h	Moisture
Sulfur di oxide	Nm^3/h		45	45	47	47	47	46	43	45	45				0	3	0						Nm^3/h	Sulfur di oxide
Sulfur tri oxide	Nm^3/h		0	0	0	0	0	0	0	0	0				0	0	0						Nm3/h	Sulfur trioxide
Nitrogen oxide	Nm^3/h		0	0	0	0	0	0	0	0	0				0	0	0						Nm3/h	Nitrogen oxide
Nitrogen dioxide	Nm^3/h		185	185	184	186	186	27	25	28	28				0	2	0						Nm^3/h	Nitrogen di oxide
Argon	Nm^3/h		0	0	1	1	26	26	24	25	25				25	2	0						Nm3/h	Argon
Ammonia	Nm^3/h		0	0	0	0	158	2	2	2	2				0	0	0						Nm3/h	Ammonia
Total	Nm^3/h		688,272	688,272	714,971	725,054	728,310	728,392	678,935	691,763	691,763		9,363		3,097	49,517	10,087	129		2,521		221	Nm^3/h	Total
Mass Flow																								Mass Flow
Nitrogen	kg/h	1,076,862	538,431	538,431	559,328	569,038	571,675	571,973	533,137	541,362	541,362		9,247		2,637	38,751	9,710	48		2,489		219	kg/h	Nitrogen
Carbon di oxide	kg/h	282,412	141,206	141,206	146,662	148,055	148,333	148,333	138,262	141,485	141,485				279	10,128	1,392						kg/h	Carbon di oxide
Oxygen	kg/h	96,998	48,499	48,499	50,388	50,600	51,234	51,120	47,649	48,908	48,908		2,808		633	3,501	212			756		66	kg/h	Oxygen
Moisture	kg/h	243,564	121,782	121,782	126,509	127,680	127,984	128,176	119,473	122,464	122,464				304	8,766	1,171	72			224		kg/h	Moisture
Sulfur di oxide	kg/h	258	129	129	134	134	134	133	124	128	128				0	9							kg/h	Sulfur di oxide
Sulfur tri oxide	kg/h		0	0	0	0	0	2	2	2	2				0	0							kg/h	Sulfur trioxide
Nitrogen oxide	kg/h		0	0	0	0	0	0	0	0	0				0	0							kg/h	Nitrogen oxide
Nitrogen di oxide	kg/h	758	379	379	378	382	382	56	52	57	57				0	4	4						kg/h	Nitrogen di oxide
Argon	kg/h		0	0	2	2	47	47	44	44	44				44	3							kg/h	Argon
Ammonia	kg/h		0	0	0	0	121	1	1	1	1			121	0	0							kg/h	Ammonia
Particulate	kg/h	32	16	16	17	17	17	17	15	16	16				0	1							kg/h	Particulate
Urea	kg/h																				224		kg/h	Urea
Total	kg/h	1,700,884	850,442	850,442	883,419	895,908	899,926	899,857	838,758	854,468	854,467		12,054	121	3,897	61,164	12,489	121		3,245	448	285	kg/h	Total
Nitrogen	lb/h		1,185,971	1,185,971	1,232,000	1,253,388	1,259,196	1,259,852	1,174,310	1,192,428	1,192,428		20,367	0	5,808	85,355	21,387	106		5,483		482	lb/h	Nitrogen
Carbon di oxide	lb/h		311,026	311,026	323,044	326,111	326,725	326,725	304,541	311,640	311,640			0	614	22,308	3,067	0					lb/h	Carbon di oxide
Oxygen	lb/h		106,826	106,826	110,988	111,454	112,849	112,599	104,954	107,727	107,727		6,184	0	1,395	7,711	467	0		1,665		146	lb/h	Oxygen
Moisture	lb/h		268,242	268,242	278,655	281,234	281,903	282,325	263,156	269,745	269,745			0	669	19,309	2,579	159			493		lb/h	Moisture
Sulfur di oxide	lb/h		284	284	295	295	295	292	272	281	281			0	0	20		0					lb/h	Sulfur di oxide
Sulfur tri oxide	lb/h		0	0	0	0	0	4	3	4	4				0	0							lb/h	Sulfur trioxide
Nitrogen oxide	lb/h		0	0	0	0	0	0	0	0	0				0	0							lb/h	Nitrogen oxide
Nitrogen di oxide	lb/h		835	835	832	841	841	122	114	127	125			0	0	9	9	0					lb/h	Nitrogen di oxide
Argon	lb/h		0	0	5	5	103	103	96	98	98				98	7							lb/h	Argon
Ammonia	lb/h		0	0	0	0	266	3	3	3	3				0	0							lb/h	Ammonia
Particulate	lb/h		35	35	37	37	37	37		35	35				0	3							lb/h	Particulate
Urea	lb/h																				493		lb/h	Urea
Total	lb/h		1,873,220	1,873,220	1,945,856	1,973,365	1,982,215	1,982,063	1,847,450	1,882,088	1,882,087		26,552	0	8,584	134,722	27,509	266		7,148	986	628	lb/h	Total
Composition																								Composition
Nitrogen	Mass-parts		0.633	0.633	0.633	0.635	0.635	0.636	0.636	0.634	0.634		0.767		0.677	0.634	0.777			0.767		0.767	Mass-parts	Nitrogen
Carbon di oxide	Mass-parts		0.166	0.166	0.166	0.165	0.165	0.165	0.165	0.166	0.166		0.000		0.072	0.166	0.111						Mass-parts	Carbon di oxide
Oxygen	Mass-parts		0.057	0.057	0.057	0.056	0.057	0.057	0.057	0.057	0.057		0.233		0.163	0.057	0.017			0.233		0.233	Mass-parts	Oxygen
Moisture	Mass-parts		0.143	0.143	0.143	0.143	0.142	0.142	0.142	0.143	0.143		0.000		0.078	0.143	0.094				0.5		Mass-parts	Moisture
Sulfur di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Sulfur di oxide
Sulfur tri oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Sulfur trioxide
Nitrogen oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen oxide
Nitrogen di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen di oxide
Argon	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.011	0.000	0.000						Mass-parts	Argon
Ammonia	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Ammonia
Particulate	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Particulate
Urea	Mass-parts																				0.5		Mass-parts	Urea
Total	Mass-parts		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000		1.000	0.000	0.989	1.000	1.000	0.000		1.000	1.000	1.000	Mass-parts	Total
Density	kg/Nm^3		1.236	1.236	1.236	1.236	1.236	1.235	1.235	1.235	1.235													
Cp	kJ/kgK		1.125693116	1.1266306	1.1861124	1.193726213	1.19372621	1.193726213	1.193726213	1.133004044	1.133004044												kJ/kgK	Cp
Heat Content	MW		16.399	17.448	78.939	87.506	87.899	87.899	81.925	24.857	24.857	8.182							0.592				MW	Heat Content
	MMBTU/hr		55.969	59.548	269.419	298.659	299.998	299.998	279.608	84.837	84.837	27.926							2.022					
NO_2	lbs/hour		834.8018	834.8018	831.9646	841.1912	841.1912	122.4702	114.1547	126.5634	125.2203					9.0							lbs/hour	NO_2
NO_2	kg/h		379.0000	379.0000	377.7119	381.9008	381.9008	55.6015	51.8262	57.4598	56.8500					4.1							kg/h	NO_2
NO_2	Nm^3 / hour		184.6	184.6	184.0	186.1	186.1	27.1	25.2	28.0	27.7					2.0								
NO + NO_2 @ actual O_2	PPM		268.3	268.3	257.4	256.6	255.5	37.2	37.2	40.5	40.0					40.0								
NO + NO_2 @ 3 % O_2	PPM		300.6	300.6	288.4	286.7	286.1	41.6	41.6	45.4	44.9													
						NO2 Balance Check																		
Eta NOx		0.850	0.8500			kg/h	lbs/hr																	

MRY 1	Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21
	FGD Outlet	FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air
Eta NOx reactor		0.8544			0.0	0															

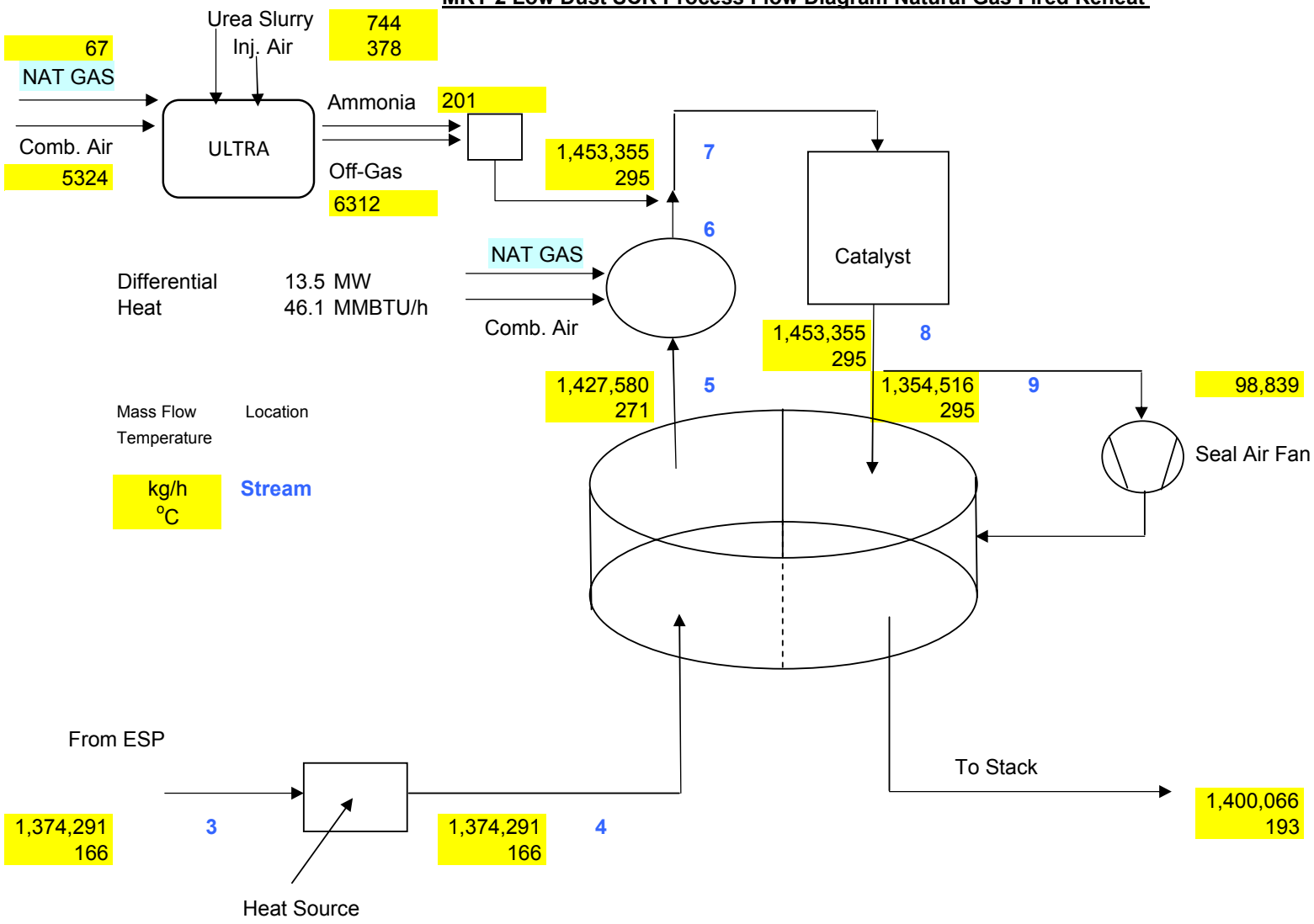
MRY 1 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



MRY 2		Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21		
		ESP Outlet	ESP Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air		
Volumetric flow rate vol.	Nm^3/h		1,072,689	1,072,689	1,114,284	1,129,869	1,135,150	1,135,286	1,058,149	1,078,363	1,078,363	1,117	14,446	263	5,018	77,189	15,563		86	4,135		293	Nm^3/h	Volumetric flow rate vol.
Volumetric flow rate vol.	scfm		676,283	676,283	702,506	712,332	715,661	715,747	667,116	679,859	679,859	704	9,107	166	3,164	48,664	9,812		54	2,607		185	scfm	Volumetric flow rate vol.
Volumetric flow rate vol.	acfm		978,672	978,672	1,273,531	1,351,693	1,361,282	1,371,355	1,279,731	1,082,007	1,082,007												acfm	Volumetric flow rate vol.
Mass Flow	kg/h		1,374,291	1,374,291	1,427,580	1,446,843	1,453,355	1,453,355	1,354,516	1,400,066	1,400,066	871	18,392	201	6,312	98,839	19,263	201	67	5,324	744	378	kg/h	Mass Flow
Mass Flow	lb/hour		3,027,072	3,027,072	3,144,449	3,186,879	3,201,223	3,201,223	2,983,516	3,083,845	3,083,845	1,918	40,512	442	13,902	217,707	42,430	442	148	11,726	1,638	832	lb/hour	Mass Flow
Temperature	Degree F	331	331	331	520	564	564	564	564	380	380												Degree F	Temperature
Temperature	Degree C		166	166	271	295	295	295	295	193	193												Degree C	Temperature
Pressure	iwg		14.5	13.5	10	9	8	5	4.5	0	0													Pressure
Composition																								Composition
Nitrogen	Vol-parts		0.6879	0.6879	0.6879	0.6890	0.6888	0.6891	0.6891	0.6878	0.6878		0.7900		0.6790		0.7705	0.2999		0.7900		0.7900	Vol-parts	Nitrogen
Carbon di oxide	Vol-parts		0.1156	0.1156	0.1156	0.1150	0.1146	0.1146	0.1146	0.1152	0.1152				0.0467		0.0703						Vol-parts	Carbon di oxide
Oxygen	Vol-parts		0.0525	0.0525	0.0525	0.0520	0.0524	0.0523	0.0523	0.0527	0.0527		0.2100		0.1422		0.0147			0.2100		0.2100	Vol-parts	Oxygen
Moisture	Vol-parts		0.1422	0.1422	0.1423	0.1423	0.1422	0.1425	0.1425	0.1428	0.1428				0.1240		0.1445	0.7001					Vol-parts	Moisture
Sulfur di oxide	Vol-parts		0.0015	0.0015	0.0015	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014						0.0000						Vol-parts	Sulfur di oxide
Sulfur tri oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Sulfur trioxide
Nitrogen oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen oxide
Nitrogen di oxide	Vol-parts		0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen di oxide
Argon	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				0.0081		0.0000						Vol-parts	Argon
Ammonia	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Ammonia
Total			1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000		1.0000		1.0000		1.0000	1.0000		1.0000		1.0000	Vol-parts	Total
Volumetric Flow			0																					Volumetric Flow
Nitrogen	Nm^3/h		737,868	737,868	766,494	778,477	781,884	782,281	729,129	741,666	741,666		11,412		3,407	53,088	11,991	64		3,267		232	Nm^3/h	Nitrogen
Carbon di oxide	Nm^3/h		124,008	124,008	128,799	129,893	130,127	130,127	121,286	124,243	124,243				234	8,893	1,094						Nm^3/h	Carbon di oxide
Oxygen	Nm^3/h		56,358	56,358	58,552	58,781	59,495	59,363	55,329	56,810	56,810		3,034		714	4,066	229			868		62	Nm^3/h	Oxygen
Moisture	Nm^3/h		152,571	152,571	158,521	160,768	161,390	161,787	150,794	153,977	153,977				622	11,022	2,249	150					Nm^3/h	Moisture
Sulfur di oxide	Nm^3/h		1,578	1,578	1,638	1,638	1,638	1,622	1,512	1,562	1,562				0	112	0						Nm^3/h	Sulfur di oxide
Sulfur tri oxide	Nm^3/h		0	0	1	1	1	17	15	16	16				0	1	0						Nm3/h	Sulfur trioxide
Nitrogen oxide	Nm^3/h		0	0	0	0	0	0	0	0	0				0	0	0						Nm3/h	Nitrogen oxide
Nitrogen dioxide	Nm^3/h		307	307	306	309	309	45	42	47	46				0	3	0						Nm^3/h	Nitrogen di oxide
Argon	Nm^3/h		0	0	2	2	42	42	40	40	40				40	3	0						Nm3/h	Argon
Ammonia	Nm^3/h		0	0	0	0	263	3	3	3	3				0	0	0						Nm3/h	Ammonia
Total	Nm^3/h		1,072,689	1,072,689	1,114,312	1,129,869	1,135,150	1,135,286	1,058,149	1,078,363	1,078,363		14,446		5,018	77,189	15,563	214		4,135		293	Nm^3/h	Total
Mass Flow																								Mass Flow
Nitrogen	kg/h	1,844,900	922,450	922,450	958,237	973,218	977,478	977,973	911,525	927,199	927,199		14,267		4,259	66,369	14,982	80		4,084		290	kg/h	Nitrogen
Carbon di oxide	kg/h	487,068	243,534	243,534	252,943	255,091	255,551	255,551	238,188	243,994	243,994				460	17,465	2,148						kg/h	Carbon di oxide
Oxygen	kg/h	160,950	80,475	80,475	83,609	83,935	84,955	84,766	79,007	81,121	81,121		4,332		1,019	5,807	327			1,240		88	kg/h	Oxygen
Moisture	kg/h	245,312	122,656	122,656	127,439	129,246	129,746	130,065	121,227	123,786	123,786				500	8,861	1,807	120			372		kg/h	Moisture
Sulfur di oxide	kg/h	9,020	4,510	4,510	4,682	4,682	4,682	4,636	4,321	4,465	4,465				0	320							kg/h	Sulfur di oxide
Sulfur tri oxide	kg/h		0	0	3	3	3	59	55	56	56				0	4							kg/h	Sulfur trioxide
Nitrogen oxide	kg/h		0	0	0	0	0	0	0	0	0				0	0							kg/h	Nitrogen oxide
Nitrogen di oxide	kg/h	1,261	631	631	628	635	635	92	86	96	95				0	7	6						kg/h	Nitrogen di oxide
Argon	kg/h		0	0	4	4	76	76	71	72	72				72	5							kg/h	Argon
Ammonia	kg/h		0	0	0	0	201	2	2	2	2			201	0	0							kg/h	Ammonia
Particulate	kg/h	70	35	35	36	36	36	36	34	35	35				0	3							kg/h	Particulate
Urea	kg/h																				372		kg/h	Urea
Total	kg/h	2,748,581	1,374,291	1,374,291	1,427,580	1,446,850	1,453,362	1,453,257	1,354,516	1,380,827	1,380,826		18,599	201	6,312	98,839	19,270	201		5,324	744	378	kg/h	Total
Nitrogen	lb/h		2,031,828	2,031,828	2,110,654	2,143,653	2,153,035	2,154,126	2,007,764	2,042,288	2,042,288		31,425	0	9,382	146,186	32,999	177		8,995		638	lb/h	Nitrogen
Carbon di oxide	lb/h		536,419	536,419	557,143	561,875	562,889	562,889	524,643	537,433	537,433			0	1,014	38,469	4,732	0					lb/h	Carbon di oxide
Oxygen	lb/h		177,258	177,258	184,160	184,880	187,125	186,709	174,023	178,682	178,682		9,541	0	2,245	12,790	720	0		2,731		194	lb/h	Oxygen
Moisture	lb/h		270,167	270,167	280,703	284,682	285,784	286,486	267,021	272,656	272,656			0	1,102	19,517	3,979	265			819		lb/h	Moisture
Sulfur di oxide	lb/h		9,934	9,934	10,312	10,312	10,312	10,213	9,519	9,835	9,835			0	0	704		0					lb/h	Sulfur di oxide
Sulfur tri oxide	lb/h		0	0	6	6	6	130	121	124	124				0	9							lb/h	Sulfur trioxide
Nitrogen oxide	lb/h		0	0	0	0	0	0	0	0	0				0	0							lb/h	Nitrogen oxide
Nitrogen di oxide	lb/h		1,389	1,389	1,384	1,398	1,398	204	190	210	208			0	0	15	14	0					lb/h	Nitrogen di oxide
Argon	lb/h		0	0	8	8	167	167	156	159	159				159	11							lb/h	Argon
Ammonia	lb/h		0	0	0	0	442	5	4	5	5				0	0							lb/h	Ammonia
Particulate	lb/h		77	77	80	80	80	80		77	77				0	6							lb/h	Particulate
Urea	lb/h																				819		lb/h	Urea
Total	lb/h		3,027,072	3,027,072	3,144,449	3,186,893	3,201,237	3,201,008	2,983,441	3,041,469	3,041,467		40,967	0	13,902	217,707	42,444	442		11,726	1,638	832	lb/h	Total
Composition																								Composition
Nitrogen	Mass-parts		0.671	0.671	0.671	0.673	0.673	0.673	0.673	0.671	0.671		0.767		0.675	0.671	0.777			0.767		0.767	Mass-parts	Nitrogen
Carbon di oxide	Mass-parts		0.177	0.177	0.177	0.176	0.176	0.176	0.176	0.177	0.177		0.000		0.073	0.177	0.111						Mass-parts	Carbon di oxide
Oxygen	Mass-parts		0.059	0.059	0.059	0.058	0.058	0.058	0.058	0.059	0.059		0.233		0.161	0.059	0.017			0.233		0.233	Mass-parts	Oxygen
Moisture	Mass-parts		0.089	0.089	0.089	0.089	0.089	0.089	0.089	0.090	0.090		0.000		0.079	0.090	0.094				0.5		Mass-parts	Moisture
Sulfur di oxide	Mass-parts		0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003		0.000		0.000	0.003	0.000						Mass-parts	Sulfur di oxide
Sulfur tri oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Sulfur trioxide
Nitrogen oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen oxide
Nitrogen di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen di oxide
Argon	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.011	0.000	0.000						Mass-parts	Argon
Ammonia	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Ammonia
Particulate	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Particulate
Urea	Mass-parts																				0.5		Mass-parts	Urea
Total	Mass-parts		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000		1.000	0.000	0.989	1.000	1.000	0.000		1.000	1.000	1.000	Mass-parts	Total
Density	kg/Nm^3		1.281	1.281	1.281	1.281	1.280	1.280	1.280	1.280	1.280													
Cp	kJ/kgK		1.104243094	1.1042431	1.1351465	1.142572233	1.14257223	1.142572233	1.142572233	1.111950928	1.111950928												kJ/kgK	Cp
Heat Content	MW		70.023	70.023	122.082	135.591	136.201	136.201	126.938	83.598	83.598	12.624							0.976				MW	Heat Content
	MMBTU/hr		238.988	238.988	416.667	462.771	464.854	464.854	433.241	285.319	285.319	43.087							3.331					
NO_2	lbs/hour		1388.7665	1388.7665	1384.0464	1398.2822	1398.2822	203.5779	189.7458	210.3873	208.3150					14.9							lbs/hour	NO_2
NO_2	kg/h		630.5000	630.5000	628.3571	634.8201	634.8201	92.4244	86.1446	95.5158	94.5750					6.8							kg/h	NO_2
NO_2	Nm^3 / hour		307.2	307.2	306.1	309.3	309.3	45.0	42.0	46.5	46.1					3.3								
NO + NO_2 @ actual O_2	PPM		286.3	286.3	274.7	273.7	272.4	39.7	39.7	43.2	42.7					42.7								
NO + NO_2 @ 3 % O_2	PPM		327.3	327.3	314.1	311.9	311.2	45.3	45.3	49.4	48.9													
						NO2 Balance Check																		
Eta NOx		0.850	0.8500			kg/h	lbs/hr																	

MRY 2	Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21
	ESP Outlet	ESP Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air
Eta NOx reactor		0.8544			0.0	0															

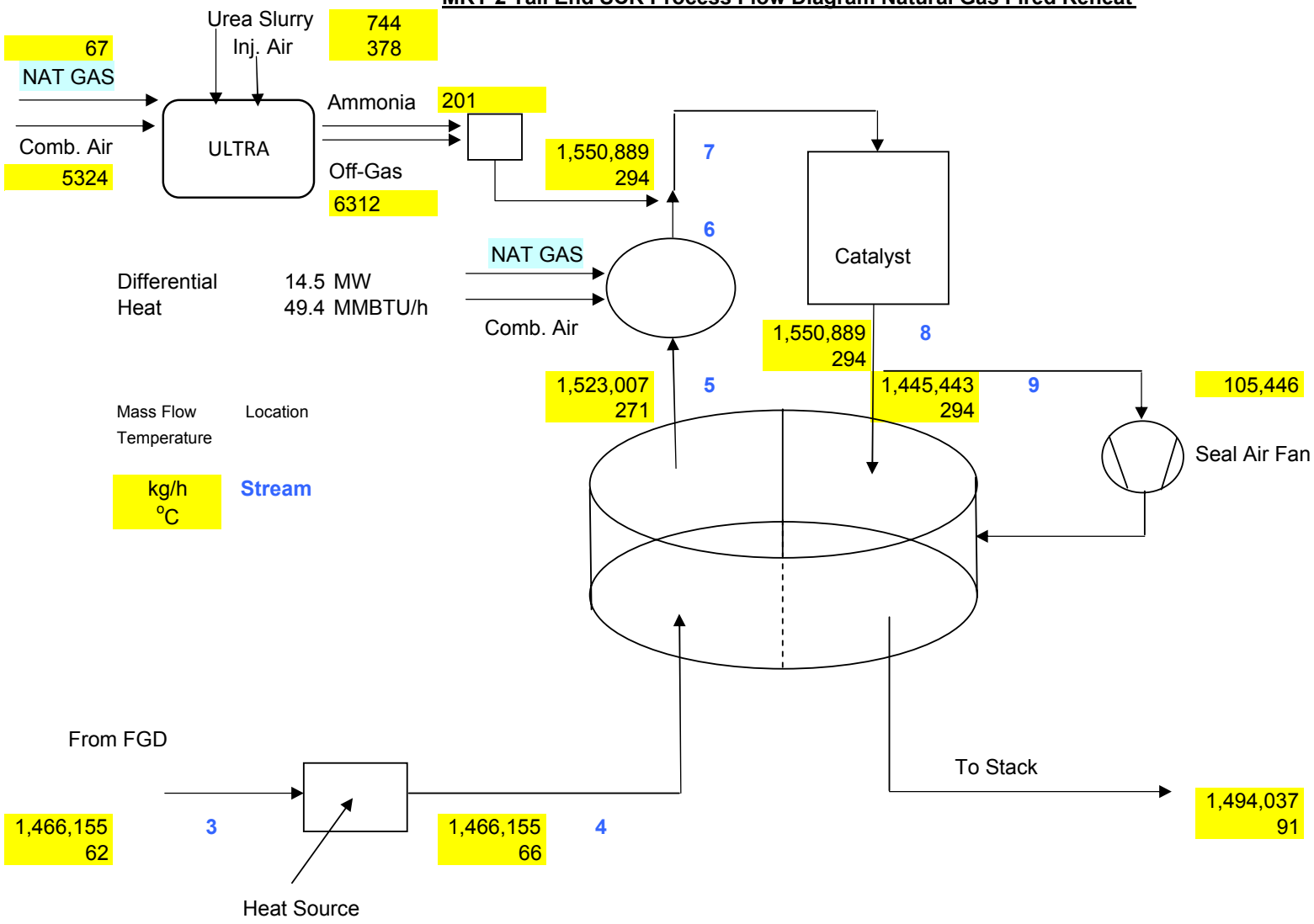
MRY 2 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



MRY 2		Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21		
		FGD Outlet	FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air		
Volumetric flow rate vol.	Nm^3/h		1,180,582	1,180,582	1,226,360	1,243,639	1,248,920	1,249,057	1,164,213	1,186,256	1,186,256	1,239	16,026	263	5,018	84,937	17,265		86	4,135		293	Nm^3/h	Volumetric flow rate vol.
Volumetric flow rate vol.	scfm		744,304	744,304	773,165	784,058	787,388	787,474	733,984	747,881	747,881	781	10,103	166	3,164	53,549	10,885		54	2,607		185	scfm	Volumetric flow rate vol.
Volumetric flow rate vol.	acfm		820,913	820,913	1,401,624	1,485,060	1,494,958	1,506,005	1,405,413	929,368	929,368												acfm	Volumetric flow rate vol.
Mass Flow	kg/h		1,466,155	1,466,155	1,523,007	1,544,376	1,550,889	1,550,889	1,445,443	1,494,037	1,494,037	966	20,404	201	6,312	105,446	21,370	201	67	5,324	744	378	kg/h	Mass Flow
Mass Flow	lb/hour		3,229,416	3,229,416	3,354,640	3,401,710	3,416,054	3,416,054	3,183,794	3,290,830	3,290,830	2,128	44,942	442	13,902	232,260	47,070	442	148	11,726	1,638	832	lb/hour	Mass Flow
Temperature	Degree F	143	143	150	520	562	562	562	562	196	196												Degree F	Temperature
Temperature	Degree C		62	66	271	294	294	294	294	91	91												Degree C	Temperature
Pressure	iwg		14.5	13.5	10	9	8	5	4.5	0	0													Pressure
Composition																								Composition
Nitrogen	Vol-parts		0.6346	0.6346	0.6346	0.6365	0.6365	0.6368	0.6368	0.6348	0.6348		0.7900		0.6790		0.7705	0.2999		0.7900		0.7900	Vol-parts	Nitrogen
Carbon di oxide	Vol-parts		0.1063	0.1063	0.1063	0.1058	0.1055	0.1055	0.1055	0.1060	0.1060				0.0467		0.0703						Vol-parts	Carbon di oxide
Oxygen	Vol-parts		0.0496	0.0496	0.0496	0.0492	0.0495	0.0494	0.0494	0.0498	0.0498		0.2100		0.1422		0.0147			0.2100		0.2100	Vol-parts	Oxygen
Moisture	Vol-parts		0.2091	0.2091	0.2091	0.2082	0.2078	0.2081	0.2081	0.2093	0.2093				0.1240		0.1445	0.7001					Vol-parts	Moisture
Sulfur di oxide	Vol-parts		0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001						0.0000						Vol-parts	Sulfur di oxide
Sulfur tri oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Sulfur trioxide
Nitrogen oxide	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen oxide
Nitrogen di oxide	Vol-parts		0.0003	0.0003	0.0002	0.0002	0.0002	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Nitrogen di oxide
Argon	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000				0.0081		0.0000						Vol-parts	Argon
Ammonia	Vol-parts		0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000						0.0000						Vol-parts	Ammonia
Total			1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000		1.0000		1.0000		1.0000	1.0000		1.0000		1.0000	Vol-parts	Total
Volumetric Flow			0																					Volumetric Flow
Nitrogen	Nm^3/h		749,220	749,220	778,295	791,589	794,996	795,393	741,365	753,019	753,019		12,660		3,407	53,917	13,302	64		3,267		232	Nm^3/h	Nitrogen
Carbon di oxide	Nm^3/h		125,507	125,507	130,357	131,571	131,805	131,805	122,852	125,741	125,741				234	9,003	1,214						Nm^3/h	Carbon di oxide
Oxygen	Nm^3/h		58,606	58,606	60,888	61,142	61,855	61,723	57,530	59,058	59,058		3,365		714	4,229	254			868		62	Nm^3/h	Oxygen
Moisture	Nm^3/h		246,863	246,863	256,451	258,944	259,566	259,963	242,305	248,269	248,269				622	17,776	2,495	150					Nm^3/h	Moisture
Sulfur di oxide	Nm^3/h		79	79	82	82	82	81	75	78	78				0	6	0						Nm^3/h	Sulfur di oxide
Sulfur tri oxide	Nm^3/h		0	0	0	0	0	1	1	1	1				0	0	0						Nm3/h	Sulfur trioxide
Nitrogen oxide	Nm^3/h		0	0	0	0	0	0	0	0	0				0	0	0						Nm3/h	Nitrogen oxide
Nitrogen dioxide	Nm^3/h		307	307	306	310	310	45	42	47	46				0	3	0						Nm^3/h	Nitrogen di oxide
Argon	Nm^3/h		0	0	2	2	42	42	40	40	40				40	3	0						Nm3/h	Argon
Ammonia	Nm^3/h		0	0	0	0	263	3	3	3	3				0	0	0						Nm3/h	Ammonia
Total	Nm^3/h		1,180,582	1,180,582	1,226,381	1,243,639	1,248,920	1,249,057	1,164,213	1,186,256	1,186,256		16,026		5,018	84,937	17,265	214		4,135		293	Nm^3/h	Total
Mass Flow																								Mass Flow
Nitrogen	kg/h	1,873,285	936,643	936,643	972,990	989,610	993,870	994,366	926,822	941,391	941,391		15,827		4,259	67,405	16,620	80		4,084		290	kg/h	Nitrogen
Carbon di oxide	kg/h	492,954	246,477	246,477	256,003	258,386	258,847	258,847	241,264	246,937	246,937				460	17,681	2,383						kg/h	Carbon di oxide
Oxygen	kg/h	167,370	83,685	83,685	86,943	87,306	88,325	88,136	82,150	84,331	84,331		4,806		1,019	6,038	363			1,240		88	kg/h	Oxygen
Moisture	kg/h	396,920	198,460	198,460	206,168	208,172	208,672	208,991	194,795	199,590	199,590				500	14,291	2,004	120			372		kg/h	Moisture
Sulfur di oxide	kg/h	450	225	225	234	234	234	231	216	223	223				0	16							kg/h	Sulfur di oxide
Sulfur tri oxide	kg/h		0	0	0	0	0	3	3	3	3				0	0							kg/h	Sulfur trioxide
Nitrogen oxide	kg/h		0	0	0	0	0	0	0	0	0				0	0							kg/h	Nitrogen oxide
Nitrogen di oxide	kg/h	1,261	631	631	628	636	636	93	86	96	95				0	7	7						kg/h	Nitrogen di oxide
Argon	kg/h		0	0	4	4	76	76	71	72	72				72	5							kg/h	Argon
Ammonia	kg/h		0	0	0	0	201	2	2	2	2			201	0	0							kg/h	Ammonia
Particulate	kg/h	70	35	35	36	36	36	36	34	35	35				0	3							kg/h	Particulate
Urea	kg/h																				372		kg/h	Urea
Total	kg/h	2,932,310	1,466,155	1,466,155	1,523,007	1,544,383	1,550,896	1,550,781	1,445,443	1,472,681	1,472,680		20,633	201	6,312	105,446	21,377	201		5,324	744	378	kg/h	Total
Nitrogen	lb/h		2,063,089	2,063,089	2,143,151	2,179,758	2,189,140	2,190,232	2,041,459	2,073,549	2,073,549		34,862	0	9,382	148,469	36,607	177		8,995		638	lb/h	Nitrogen
Carbon di oxide	lb/h		542,901	542,901	563,883	569,133	570,147	570,147	531,419	543,915	543,915			0	1,014	38,945	5,249	0					lb/h	Carbon di oxide
Oxygen	lb/h		184,328	184,328	191,505	192,304	194,549	194,133	180,947	185,752	185,752		10,585	0	2,245	13,300	799	0		2,731		194	lb/h	Oxygen
Moisture	lb/h		437,137	437,137	454,114	458,528	459,630	460,333	429,064	439,625	439,625			0	1,102	31,478	4,414	265			819		lb/h	Moisture
Sulfur di oxide	lb/h		496	496	514	514	514	510	475	491	491			0	0	35		0					lb/h	Sulfur di oxide
Sulfur tri oxide	lb/h		0	0	0	0	0	6	6	6	6				0	0							lb/h	Sulfur trioxide
Nitrogen oxide	lb/h		0	0	0	0	0	0	0	0	0				0	0							lb/h	Nitrogen oxide
Nitrogen di oxide	lb/h		1,389	1,389	1,384	1,400	1,400	204	190	211	208			0	0	15	16	0					lb/h	Nitrogen di oxide
Argon	lb/h		0	0	8	8	167	167	156	159	159				159	11							lb/h	Argon
Ammonia	lb/h		0	0	0	0	442	5	5	5	5				0	0							lb/h	Ammonia
Particulate	lb/h		77	77	80	80	80	80		77	77				0	6							lb/h	Particulate
Urea	lb/h																				819		lb/h	Urea
Total	lb/h		3,229,416	3,229,416	3,354,640	3,401,726	3,416,070	3,415,817	3,183,720	3,243,791	3,243,788		45,446	0	13,902	232,260	47,086	442		11,726	1,638	832	lb/h	Total
Composition																								Composition
Nitrogen	Mass-parts		0.639	0.639	0.639	0.641	0.641	0.641	0.641	0.639	0.639		0.767		0.675	0.639	0.777			0.767		0.767	Mass-parts	Nitrogen
Carbon di oxide	Mass-parts		0.168	0.168	0.168	0.167	0.167	0.167	0.167	0.168	0.168		0.000		0.073	0.168	0.111						Mass-parts	Carbon di oxide
Oxygen	Mass-parts		0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057		0.233		0.161	0.057	0.017			0.233		0.233	Mass-parts	Oxygen
Moisture	Mass-parts		0.135	0.135	0.135	0.135	0.135	0.135	0.135	0.136	0.136		0.000		0.079	0.136	0.094				0.5		Mass-parts	Moisture
Sulfur di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Sulfur di oxide
Sulfur tri oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Sulfur trioxide
Nitrogen oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen oxide
Nitrogen di oxide	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Nitrogen di oxide
Argon	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.011	0.000	0.000						Mass-parts	Argon
Ammonia	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Ammonia
Particulate	Mass-parts		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000		0.000	0.000	0.000						Mass-parts	Particulate
Urea	Mass-parts																				0.5		Mass-parts	Urea
Total	Mass-parts		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000		1.000	0.000	0.989	1.000	1.000	0.000		1.000	1.000	1.000	Mass-parts	Total
Density	kg/Nm^3		1.242	1.242	1.242	1.242	1.242	1.242	1.242	1.241	1.241													
Cp	kJ/kgK		1.118792829	1.1197279	1.1788636	1.186311705	1.18631171	1.186311705	1.186311705	1.126080331	1.126080331												kJ/kgK	Cp
Heat Content	MW		28.098	29.895	135.259	149.739	150.371	150.371	140.147	42.575	42.575	14.005							0.976				MW	Heat Content
	MMBTU/hr		95.899	102.032	461.638	511.060	513.215	513.215	478.321	145.309	145.309	47.799							3.331					
NO_2	lbs/hour		1388.7665	1388.7665	1384.0495	1399.8420	1399.8420	203.8050	189.9613	210.6144	208.3150					14.9							lbs/hour	NO_2
NO_2	kg/h		630.5000	630.5000	628.3585	635.5283	635.5283	92.5275	86.2425	95.6189	94.5750					6.8							kg/h	NO_2
NO_2	Nm^3 / hour		307.2	307.2	306.1	309.6	309.6	45.1	42.0	46.6	46.1					3.3								
NO + NO_2 @ actual O_2	PPM		260.2	260.2	249.6	249.0	247.9	36.1	36.1	39.3	38.8					38.8								
NO + NO_2 @ 3 % O_2	PPM		292.0	292.0	280.2	278.6	278.1	40.5	40.5	44.1	43.6													
						NO2 Balance Check																		
Eta NOx		0.850	0.8500			kg/h	lbs/hr																	

MRY 2	Input Data	3	4	5	6	7	8	9	10	11	12	13	14	15	17	12+13	14 Reacted	18	19	20	21
	FGD Outlet	FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Booster fan in	Booster fan out	Natural Gas	Combustion Air	Ammonia	ULTRA Off-Gas	Purge+Scavange	Burner Flue Gas		ULTRA Natural Gas	ULTRA Combustion Air	ULTRA Urea Slurry	ULTRA Injection Air
Eta NOx reactor		0.8544			0.1	0															

MRY 2 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



Blakley, Robert

From: Bryant, Ronald

Sent: Friday, August 07, 2009 3:05 PM

To: 'Wayne Jones'; Nate White; Luther Kvernen (lkvernen@minnkota.com); John Graves; Andy Freidt; sbenson@undeerc.org; Weilert, Carl; Blakley, Robert

Cc: 51684

Subject: Revised Agenda for Monday Meeting

Attachments: SCR Economic Study Catalyst Meeting Agenda August 10 2009 Rev3.docx

Attached is the revised agenda for our meeting Monday afternoon.

Ron

MINNKOTA – MRY STATION SCR COST STUDY MEETING

Monday, August 10, 2009
1:00 PM
Meeting Location: Haldor Topsoe, Inc., Houston, Texas

Meeting Participants:

Haldor Topsoe, Inc.
- Wayne Jones, Sales Manager, Power Generation (Houston)
- Nathan White, Director, Business Development (Houston)

Minnkota Power Cooperative, Inc.
- Luther Kvernen, Vice President - Generation (Grand Forks Headquarters)
- John Graves, Environmental Manager (Grand Forks Headquarters)
- Andy Freidt, Permit and Compliance Engineer (MRY Station)

University of North Dakota and Microbeam Technologies
- Steven Benson, PhD, Professor, Department of Chemical Engineering at University of North Dakota and President, Microbeam Technologies, Inc

Burns & McDonnell
- Ron Bryant, Burns & McDonnell project manager for Minnkota air pollution control projects
- Carl Weilert, Burns & McDonnell principal engineer for powerplant air pollution control projects
- Robert Blakley, Burns & McDonnell project engineer for Minnkota's NOx reduction program

Meeting Purpose:

1. To develop a common understanding of the purpose, unique challenges and status of Minnkota's cost study for low dust and tail end SCR technologies.
2. Discuss Haldor Topsoe's experience with SCR catalyst and how it may relate to the application of high sodium and potassium aerosols associated with the combustion of ND lignite in cyclone fired boilers.

AGENDA

1. Introductions

2. Review Meeting Purpose and Agenda

3. Minnkota/MRY Station Background – Luther Kvernen (10 minutes)
- Organization
- SCR cost study

4. ND Lignite (Center Mine) Characteristics – Steve Benson (10 minutes)

5. SCR cost study – Burns & McDonnell (10 minutes)

- Impact of catalyst volumes and deactivation rates
    - Input requirements to provide reasonable cost estimates

6. Haldor Topsoe Background – (10 minutes)

- Organization
- Experience with SCR catalyst for this type of application

7. Identify specific questions/concerns – All

8. Exploration of opportunities – All

9. Action items

10. Other

Bryant, Ronald

From: Bryant, Ronald

Sent: Friday, August 07, 2009 3:13 PM

To: 'Noel Rosha'; Greg Holscher; James Ferrigan; Luther Kvernen (lkvernen@minnkota.com); John Graves; Andy Freidt; sbenson@undeerc.org; Weilert, Carl; Blakley, Robert

Cc: 51684

Subject: Revised Agenda for Tuesday Meeting

Attachments: SCR Economic Study Catalyst Meeting Agenda August 11 2009 Rev3.docx

Attached is the revised agenda for our 9:00 AM meeting Tuesday morning at Burns & McDonnell offices.

Ron

MINNKOTA – MRY STATION SCR COST STUDY MEETING

Tuesday, August 11, 2009
9:00 AM
Meeting Location: Burns & McDonnell with CERAM Environmental, Inc.

Meeting Participants:

CERAM Environmental, Inc.

- Noel Rosha, Senior Applications Engineer (Kansas City)
- Dr. Greg Holscher, Senior Applications Engineer (Kansas City)
- Jim Ferrigan, CRF Environmental, Inc. Sales Representative (Kansas City)

Minnkota Power Cooperative, Inc.

- Luther Kvernen, Vice President - Generation (Grand Forks Headquarters)
- John Graves, Environmental Manager (Grand Forks Headquarters)
- Andy Freidt, Permit and Compliance Engineer (MRY Station)

University of North Dakota and Microbeam Technologies

- Steven Benson, PhD, Professor, Department of Chemical Engineering at University of North Dakota and President, Microbeam Technologies, Inc

Burns & McDonnell

- Ron Bryant, Burns & McDonnell project manager for Minnkota air pollution control projects
- Carl Weilert, Burns & McDonnell principal engineer for powerplant air pollution control projects
- Robert Blakley, Burns & McDonnell project engineer for Minnkota's NOx reduction program

Meeting Purpose:

1. To develop a common understanding of the purpose, unique challenges and status of Minnkota's cost study for low dust and tail end SCR technologies.
2. Discuss CERAM Environmental, Inc. experience with SCR catalyst and how it may relate to the application of high sodium and potassium aerosols associated with the combustion of ND lignite in cyclone fired boilers.

AGENDA

1. Introductions

2. Review Meeting Purpose and Agenda

3. Minnkota/MRY Station Background – Luther Kvernen (10 minutes)

- Organization
- SCR cost study

4. ND Lignite (Center Mine) Characteristics – Steve Benson (10 minutes)

5. SCR cost study – Burns & McDonnell (10 minutes)

- Impact of catalyst volumes and deactivation rates
    - Input requirements to provide reasonable cost estimates

6. CERAM Environmental Inc. – (10 minutes)

- Organization
- Experience with SCR catalyst for this type of application

7. Identify specific questions/concerns – All

8. Exploration of opportunities – All

9. Action items

10. Other

Bryant, Ronald

From: Noel Rosha [Noel.Rosha@ceram-usa.com]
Sent: Thursday, August 13, 2009 11:18 AM
To: Bryant, Ronald
Cc: James Ferrigan; Greg Holscher; John Cochran
Subject: Minnkota MR Young Presentation
Attachments: Low Dust & Tail End 2009 Reference List.pdf; Minnkota MR Young Presentation at B&McD 090811.pdf

Ron,

Attached, please find a copy of our presentation from the meeting with Minnkota this week. I have also included our low dust/tail end experience list. Thanks again for the opportunity to meet with everyone to discuss this unique project.

Best regards

Noel Rosha, P.E.
Applications Engineer

CERAM Environmental, Inc.
Phone: 913-239-9896
Mobile: 913-638-9672

Low Dust Tail End Reference List as of April 2009

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
1	**SMVA Munster**	AEE	Wehreswissensch. Institut	DEU	chem. weapon, cumbustion, Tail end	4 m³	1997
2	**BMC Moerdijk**	AEE	BMC Moerdijk BV	NLD	Chicken litter, Tail end	20 m³	2007
3	**Sulcis 3**	ENEL	ENEL	ITA	Coal / Oil, Tail end	127 m³	1999
4	**Killen**	Black & Veatch	Dayton Power & Light	USA	Coal, Low dust	326 m³	2002
5	**Killen Unit 2**	Dayton Power & Light	Dayton Power & Light	USA	Coal, Low Dust, Additional delivery	164 m³	2008
6	**Karlsruhe**	DBA	EnBW	DEU	Coal, Tail end	60 m³	1988
7	**Herne 1, 2, 3**	KWH	STEAG	DEU	Coal, Tail end	501 m³	1989
8	**Voerde West I/II**	KWH	STEAG	DEU	Coal, Tail end	535 m³	1989
9	**Lünen 11**	KWH	STEAG	DEU	Coal, Tail end	243 m³	1989
10	**Lünen 10**	KWH	STEAG	DEU	Coal, Tail end	94 m³	1989
11	**STEAG Repl., 1 layer**	STEAG	STEAG	DEU	Coal, Tail End	46 m³	1991
12	**Lünen 11**	BASF	STEAG	DEU	Coal, Tail end	80 m³	1994
13	**Ibbenbüren**	BASF	Preussag / RWE	DEU	Coal, Tail end	143 m³	1994
14	**Elenac - Werk Wesseling Unit 20-24**	BASF	Elenac GmbH	DEU	Ethylencracker, Tail end	51 m³	2001
15	**Elenac - Werk Wesseling**	BASF	Elenac GmbH	DEU	Ethylencracker, Tail end, Additional delivery	8 m³	2001
16	**UMEA Biomasse**	ELEX	Umea Energi AB	SWE	Fresh wood, Peat, Low dust	89 m³	2008
17	**BASF Residue Incin. N800**	BASF	BASF	DEU	Hazardous waste, Low dust	233 m³	1995
18	**BASF N806**	BASF	BASF	DEU	Hazardous waste, Low dust	24 m³	1997
19	**MVA Constanti**	BASF	AE-Energietechnik	ESP	Hazardous waste, Low dust	29 m³	1998
20	**BASF N806**	BASF	BASF	DEU	Hazardous waste, Low dust	8 m³	1999
21	**BASF N810**	BASF	BASF	DEU	Hazardous waste, Low dust, Additional delivery	29 m³	2001

Low Dust Tail End Reference List as of April 2009

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
22	**MVA Constanti**	BASF		ESP	Hazardous waste, Low dust, Additional delivery	10 m³	2003
23	**Bayer Dormagen**	BASF	Lentjes	DEU	Hazardous waste, Tail end	32 m³	1994
24	**Schwarzheide**	BASF	Integral	DEU	Hazardous waste, Tail end	29 m³	1995
25	**SMVA Ostrava**	AE-Energietechnik		CZE	Hazardous waste, Tail end	9 m³	1999
26	**Ostrava**	SPOVO	SPOVO	CZE	Hazardous waste, Tail end, Low temp. Additional delivery	3 m³	2005
27	**Bayer Antwerpen**	BASF	Bayer AG	BEL	Industrial waste, Tail end	13 m³	2002
28	**Deparia**	Deparia Engineering S.r.l.		ITA	Low Sulfur Oil, Diesel engine	7 m³	2001
29	**KVA Thurgau**	AEE	Verband KVA Thurgau	CHE	Municipal and industrial waste, Tail end	33 m³	1996
30	**MVA Zistersdorf**	BASF	Von Roll	AUT	Municipal Waste Tail end	41 m³	2008
31	**KVA Basel**	BASF		CHE	Municipal waste, Low dust	58 m³	1998
32	**Genf Linie 5, 6, 3**	BASF	SIG / AE-Energietechnik	CHE	Municipal waste, Low dust	139 m³	2000/01
33	**ICDI Charleroi**	HRC		BEL	Municipal waste, Low dust	7 m³	2004
34	**KVA Basel**	BASF		CHE	Municipal waste, Low dust	29 m³	2004
35	**MVA Prag Linie 1-4 Prague-Malešice**	BASF	Pražske služby	CZE	Municipal Waste, Low Dust	236 m³	2007
36	**Kuri MSWI**	SPECO	SPECO	KOR	Municipal Waste, Low Dust	18 m³	2009
37	**Genf Linie 5**	BASF	CTU	CHE	Municipal waste, Low dust, Additional delivery	55 m³	2002
38	**Genf Linie 5**	BASF	SIG	CHE	Municipal waste, Low dust, Additional delivery	72 m³	2006
39	**Genf Linie 6**	BASF	SIG / CTU	CHE	Municipal waste, Low dust, Additional delivery	72 m³	2004
40	**Genf**	BASF	Usine de Cheneviers	CHE	Municipal Waste, Low Dust, Additional delivery	72 m³	2008
41	**MVA Spittelau**	SGP	Heizbetriebe Wien	AUT	Municipal waste, Tail end	39 m³	1989
42	**MVA Spittelau Dioxin**	SGP	Heizbetriebe Wien	AUT	Municipal waste, Tail end	22 m³	1991

Low Dust Tail End Reference List as of April 2009

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
43	**MVA Flötzersteig**	AEE	Heizbetriebe Wien	AUT	Municipal waste, Tail end	52 m³	1992
44	**Nijmegen**	BASF	KRC	NLD	Municipal waste, Tail end	35 m³	1994
45	**MVA Mannheim K1-3**	BASF	EVT	DEU	Municipal waste, Tail end	86 m³	1994
46	**MVA Essen Karnap**	BASF	EVT	DEU	Municipal waste, Tail end	140 m³	1994
47	**MVA Wels**	AEE	WAV	AUT	Municipal waste, Tail end	20 m³	1995
48	**MVA Leudelingen**	BASF		LUX	Municipal waste, Tail end	16 m³	1995
49	**KVA St. Gallen**	BASF	AEE	CHE	Municipal waste, Tail end	11 m³	1996
50	**MVA Flingern**	BASF		DEU	Municipal waste, Tail end	106 m³	1996
51	**MVA Mannheim IV**	BASF		DEU	Municipal waste, Tail end	46 m³	1997
52	**MVA Buchs**	BASF	AE	CHE	Municipal waste, Tail end	54 m³	1998
53	**Creteil**	BASF	ELEX	FRA	Municipal waste, Tail end	48 m³	2001
54	**HIMTEC**	BASF		ITA	Municipal waste, Tail end	5 m³	2001
55	**MVA Bamberg**	BASF		DEU	Municipal waste, Tail end	7 m³	2001
56	**Halmstads Renhallnings AB**	BASF	BBP Environment	SWE	Municipal waste, Tail end	19 m³	2002
57	**KVA Turgi**	BASF	GV Region Baden-Brugg	CHE	Municipal waste, Tail end	11 m³	2002
58	**GMVA Oberhausen**	BASF		DEU	Municipal waste, Tail end	19 m³	2002
59	**MVA Malmö**	BASF	LAB	SWE	Municipal waste, Tail end	30 m³	2002
60	**Colleferro Unit 1 & 2**	Mosca Servizi Amb.	Termokimik	ITA	Municipal waste, Tail end	36 m³	2004
61	**WAV II Wels**	LAB GmbH	Energie AG Oberösterreich	AUT	Municipal waste, Tail end	41 m³	2005
62	**Saint Ouen Unit 1-3**	BASF	LAB / SYCTOM	FRA	Municipal waste, Tail end	219 m³	2005
63	**Brest**	Mosca Servizi Amb.	Termokimik	FRA	Municipal waste, Tail end	14 m³	2005

Low Dust Tail End Reference List as of April 2009

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
64	**MSWI Bordeaux**	BASF	ASTRIA / HRC	FRA	Municipal waste, Tail end	85 m³	2005
65	**CVDU Nice**	BASF	LAB	FRA	Municipal waste, Tail end	157 m³	2005
66	**Rennes**	BASF	Von Roll	FRA	Municipal waste, Tail end	23 m³	2005
67	**Nantes**	BASF	Von Roll	FRA	Municipal waste, Tail end	34 m³	2005
68	**Coueron / Nantes**	BASF	LAB	FRA	Municipal waste, Tail end	12 m³	2005
69	**Chaumont**	HRC	SHMVD Chaumont	FRA	Municipal waste, Tail end	13 m³	2005
70	**CENON**	Hamon	UIOM de Cenon	FRA	Municipal waste, Tail end	20 m³	2006
71	**Dunkerque**	BASF	Dunkerque Grand Littoral / Von Roll	FRA	Municipal waste, Tail end	9 m³	2007
72	**MVA Twence**	BASF	LAB	NLD	Municipal Waste, Tail end	50 m³	2007
73	**MVA Marseille**	BASF	LAB	FRA	Municipal Waste, Tail end	29 m³	2007
74	**Borsodchem NYRT**	BASF		HUN	Municipal Waste, Tail end	15 m³	2008
75	**Bazenheid**	ELEX	Bazenheid	CHE	Municipal Waste, Tail end	51 m³	2008
76	**Mida Crotone**	Hafner	Mida S.r.l.	ITA	Municipal Waste, Tail end	7 m³	2008
77	**MVA Dürnrohr Linie 3**	Envirgy	AVN	AUT	Municipal Waste, Tail end	35 m³	2009
78	**Mallorca P 3095**	BASF	TIRME SA	ESP	Municipal Waste, Tail end	45 m³	2009
79	**MSW Giubiasco**	BASF	Von Roll	DEU	Municipal Waste, Tail end	30 m³	2009
80	**KVA Thurgau**	BASF	CTU	CHE	Municipal waste, Tail end, Additional delivery	8 m³	2002
81	**Nijmegen**	BASF		NLD	Municipal waste, Tail end, Additional delivery	6 m³	2002
82	**Nijmegen Line 2**	BASF		NLD	Municipal waste, Tail end, Additional delivery	11 m³	2003
83	**KVA St. Gallen**	BASF		CHE	Municipal waste, Tail end, Additional delivery	9 m³	2003
84	**MVA Malmö**	BASF	LAB	SWE	Municipal waste, Tail end, Additional delivery	22 m³	2005

Low Dust Tail End Reference List as of April 2009

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
85	**Kimhae**	BASF	SPECO	KOR	Municipal waste, Tail end, Additional delivery	5 m³	2005
86	**Kimhae**	BASF	SPECO	KOR	Municipal waste, Tail end, Additional delivery	5 m³	2006
87	**CO-Catalyst Rotterdam**	AE-Energietechnik	AVR	NLD	Municipal waste, Tail end, CO Oxidation	6 m³	2001
88	**T.A. Lauta**	AE	STEAG	DEU	Municipal waste, Tail end, Low temp.	47 m³	2003
89	**Tirmadrid**	Integral		ESP	Municipal waste, Tail end, Low temp.	133 m³	2005
90	**Ferrara**	Alstom	Hera	ITA	Municipal waste, Tail end, Low temp.	54 m³	2006
91	**MVA Pfaffenau**	Integral	WKU / Envirgy	AUT	Municipal waste, Tail end, Low temp.	68 m³	2007
92	**Issy-les-Moulineaux**	BASF	SYCTOM / Von Roll	FRA	Municipal waste, Tail end, Low temp.	163 m³	2007
93	**Forli**	Alstom	Hera	ITA	Municipal waste, Tail end, Low temp.	44 m³	2007
94	**Ferrara**	Alstom	HERA	ITA	Municipal waste, Tail end, Low temp. Additional Delivery	44 m³	2008
95	**MVA Flötzersteig**	Integral	Fernwärme Wien	AUT	Municipal waste, Tail end, Low temperature	71 m³	2006
96	**AMSA Silla 2**	Termokimik	AMSA	ITA	Municipal Waste, Tail end, Low temperature	171 m³	2007
97	**Rimini**	Alstom	HERA	ITA	Municipal Waste, Tail end, Low temperature	44 m³	2008
98	**TBA Arnoldstein**	AEE	KRV	AUT	Municipal waste, Tail end, Low temp.	14 m³	2003
99	**MSW Reims**	Hamon	Hamon	FRA	Municipal waste, Tail end, Low temp.	31 m³	2009
100	**MSW Antibes**	Hamon	Veolia	FRA	Municipal Waste, Tail end	37 m³	2007
101	**Techwin**	BASF		KOR	Plywood plant, Tail end	7 m³	2005
102	**Constanti**	BASF		ESP	Residue, Low dust, Additional delivery	20 m³	2005
103	**Constanti**	BASF		ESP	Residue, Low dust, Additional delivery	10 m³	2007
104	**Constanti**	BASF	Gestio De Residus Especials De Catalunya, S.A.	ESP	Residue, Low dust, Additional delivery	10 m³	2007
105	**Constanti**	BASF		ESP	Residue, Low dust, Additional delivery	3 m³	2009

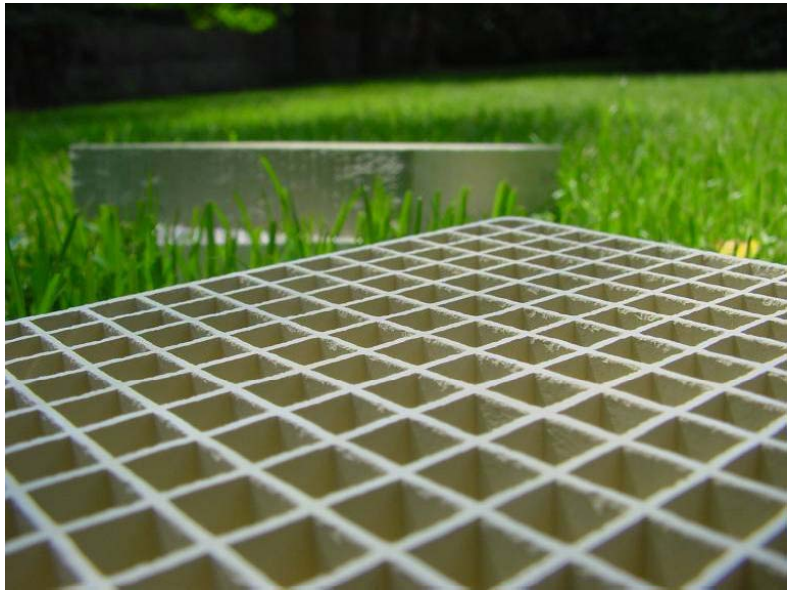
Low Dust Tail End Reference List as of April 2009

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
106	**SMVA Lonza**	AEE	Lonza AG	CHE	Residue, Tail end	25 m³	1995
107	**CZ Süd**	BASF	BASF	DEU	Residue, Tail end	3 m³	1996
108	**DOMO Caproleuna**	BASF		DEU	Residue, Tail end	3 m³	2003
109	**Recycling Komb. Rotterdam**	BASF	Steuler	NLD	Residue, Tail end	13 m³	2005
110	**BASF CZ Süd**	BASF	BASF	DEU	Residue, Tail end, Additional delivery	3 m³	2005
111	**Sammel SCR Simmering**	Envirgy	Fernwärme Wien	AUT	Sludge, Hazardous Waste, Tail end, Low temp.	125 m³	2005
112	**Hot Strip Mill - Oven 23**	Seiler	Corus Strip Products	NLD	Steel production, Low dust, Additional delivery	12 m³	2003
113	**Hot Strip Mill - Oven 24**	Seiler	Corus Strip Products	NLD	Steel production, Low dust, Additional delivery	12 m³	2003
114	**Hot Strip Mill - Oven 23**	Seiler	Corus Strip Products	NLD	Steel production, Low dust, Additional delivery	12 m³	2006
115	**Hot Strip Mill Oven 22**	Seiler	Hoogovens Staal BV	NLD	Steel production, Low dust, High temp.	37 m³	2000
116	**Hot Strip Mill Oven 21**	Seiler	Hoogovens Staal BV	NLD	Steel production, Low dust, High temp.	37 m³	2002
117	**Hot Strip Mill Oven 22**	Seiler	Hoogovens Staal BV	NLD	Steel production, Low dust, High temp., Additional del.	39 m³	2002
118	**Charlottenburg**	Steinmüller	BEW	DEU	Tail end	198 m³	1989
119	**MVA Burgkirchen**	SHL	ZAS	DEU	Waste, Tail end	24 m³	1993
120	**München Nord**	BASF	Stadtwerke München	DEU	Waste, Tail end	49 m³	1993
121	**Colombes**	Integral		FRA	Waste, Tail end	20 m³	1996
122	**MVA Lenzing**	Integral		AUT	Waste, Tail end	29 m³	1997
123	**Dalmine**	Integral		ITA	Waste, Tail end	13 m³	2000
124	**MVA Fribourg**	BASF		CHE	Waste, Tail end	33 m³	2001
125	**Nimes**	Integral		FRA	Waste, Tail end	9 m³	2003
126	**Le Havre**	Integral		FRA	Waste, Tail end	13 m³	2003

Low Dust Tail End Reference List as of April 2009

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
127	**TRV Niklasdorf**	AEE		AUT	Waste, Tail end	12 m³	2003
128	**Steuler**	BASF	Steuler	DEU	Waste, Tail end	6 m³	2005
129	**Sangju**	BASF	David Chemical	KOR	Waste, Tail end, Additional delivery	3 m³	2005
130	**MSW Ludres**	Hamon	Nancy Energie	FRA	Waste, Tail end, Low temperature	40 m³	2006
	TOTAL AMOUNT					**6946 m³**	

Presentation to
Minnkota / Burns & McDonnell
August 11, 2009



CERAM
CATALYSTS + HONEYCOMBS

CERAM Environmental, Inc.

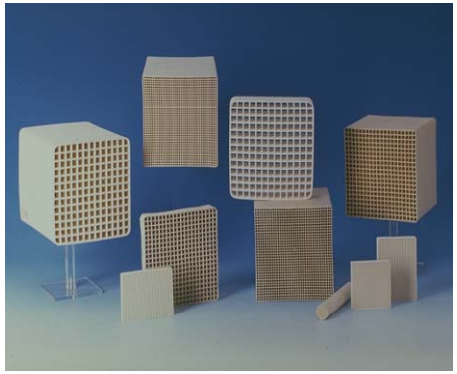
Presentation Topics

- Corporate Overview and Organization
- North Dakota Lignite Coal Analysis
- Low Dust & Tail End Catalyst Designs

CERAM ENVIRONMENTAL, INC.

CERAM Products

- DeNOx Catalyst
- Oxidation Catalyst
- Diesel Truck DeNOx Catalyst
- Heat Storage Media (RTOs)
- Casting Filters
- Specialized Porcelain and Ceramic Products



All CERAM Catalyst is Made in Our Frauental, Austria Plant (Porzellanfabrik Frauenthal, GmbH) Founded in 1921

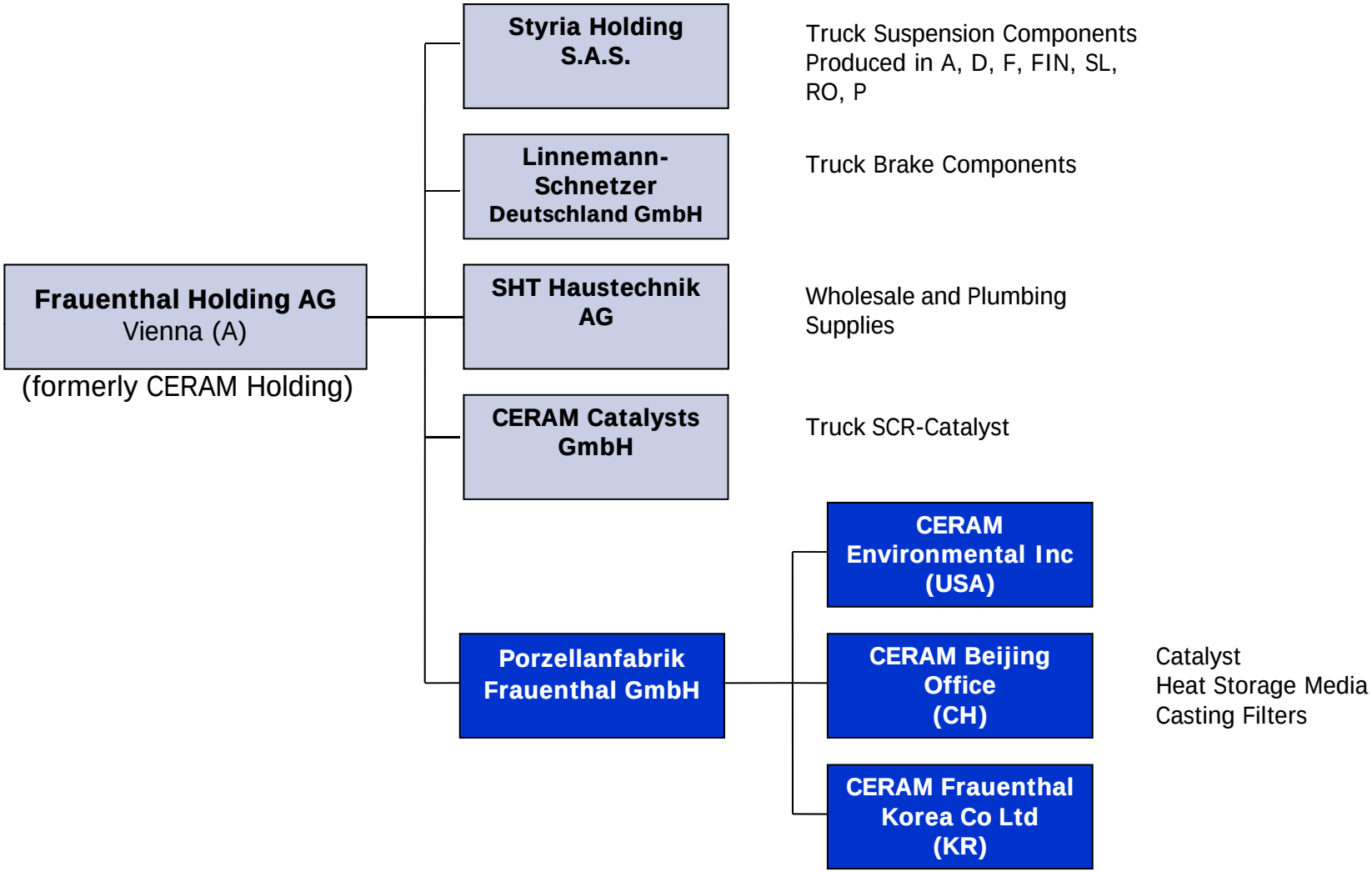
CERAM ENVIRONMENTAL, INC.

CERAM Environmental Inc.

- U.S. Based Subsidiary Founded by John Cochran in 2000
- 100% Owned by Porzellanfabrik Frauenthal
- Single Point Project Coordination
  - Flow Modeling, Delivery, Training, Startup, Guarantee Administration
- Comprehensive Direct Services
  - Flow Modeling Administration
  - AIG Tuning
  - Reactor Inspections
  - Catalyst Testing
  - SCR Operations Assessments and Troubleshooting
  - Catalyst Management and SCR Operations Planning

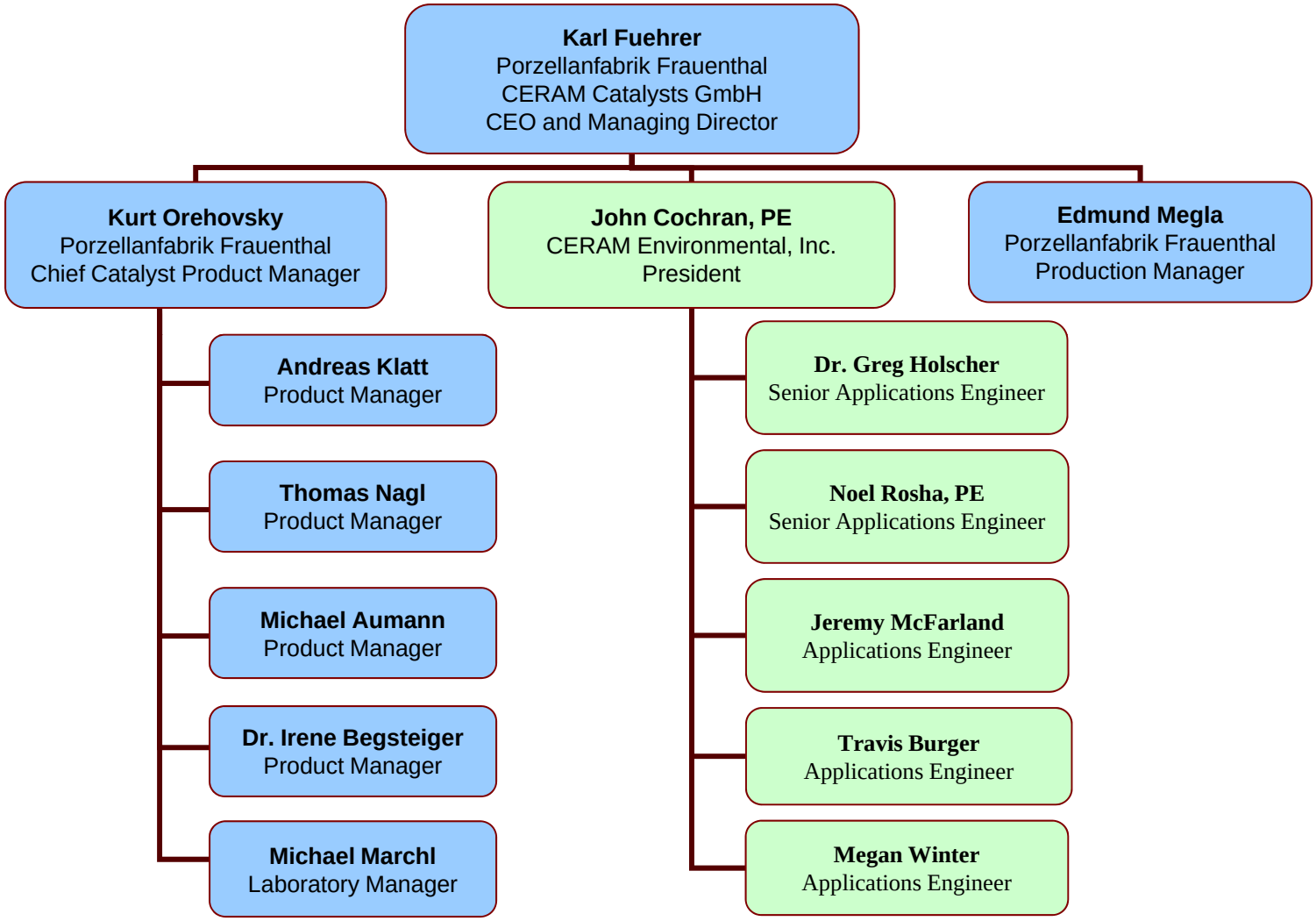
CERAM ENVIRONMENTAL, INC.

Structure of the Frauenthal Group



CERAM ENVIRONMENTAL, INC.

CERAM Organization



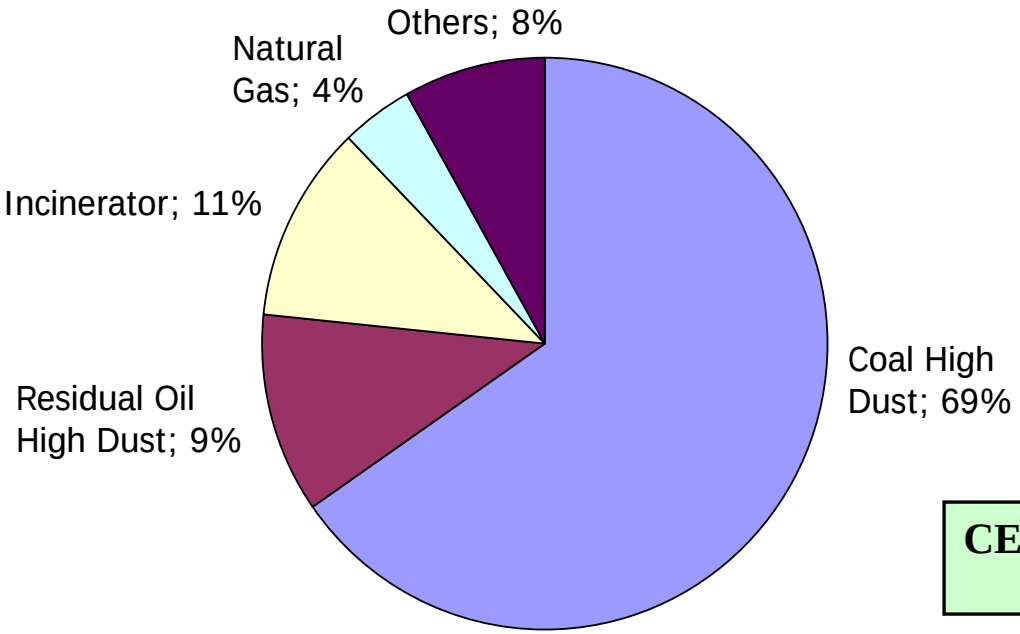
CERAM
ENVIRONMENTAL, INC.

CERAM Has Completed More Than 400 Dirty Fuel Based SCR Catalyst Supply Projects

- Bituminous Coal
- Sub-Bituminous Coal
- Brown (Lignite) Coal
- Distillate Fuel Oil
- Residual Fuel Oil

- Biomass
- Petroleum Coke
- Orimulsion
- Synthesis Gas
- Chemical Weapons

- Wood, Wood Waste and Peat
- Municipal Solid Waste
- Refuse Derived Fuel
- Industrial, Hospital, and Hazardous Waste Incinerators
- Ethylene Crackers, HNO3, and FCC Units
- Blast Furnace and Coke Oven Gas
- Steel Production and Pickling
- Glass Production Plants
- Natural Gas



CERAM's Experience Portfolio Focus' on Dirty Gas Applications

CERAM ENVIRONMENTAL, INC.

CERAM SCR/Catalyst/AQC Experience
"Boiler to Stack" Perspective

Name/Affiliation	Catalyst Applications	SCR System Design	SCR System Startups	Other Experience	Previous Affiliations
John Cochran CERAM Environmental	8 Years	7 Years 11 Units	2 Units	19 Years (FGD/ESP/CEM)	Black & Veatch
Dr. Greg Holscher CERAM Environmental	7 Years (+PhD re catalyst)		6 Units	3 Years (ESP/Baghouse/CEM)	Black & Veatch
Noel Rosha CERAM Environmental	5 Years		1 Unit	4 Years (Boilers, Draft Systems, Utility Engineer)	Black & Veatch
Jeremy McFarland CERAM Environmental	4 Years			3 Years (Field Services)	Black & Veatch
Kurt Orehovsky CERAM-Frauenthal	17 Years	7 Years 12 Units	10 Units		Uhde
Thomas Nagl CERAM-Frauenthal	9 Years	13 Years 10 Units	15 Units		Austrian Energy (Babcock Borsig)
Michael Aumann CERAM-Frauenthal	8 Years	15 Years 20 Units		10 Years (FGD/ESP)	Austrian Energy (Babcock Borsig)
Andreas Klatt CERAM-Frauenthal	17 Years				Siemens/Argillon
Total	**73 Years**	**42 Years** **53 Units**	**34 Units**		

Mitsubishi Catalyst License

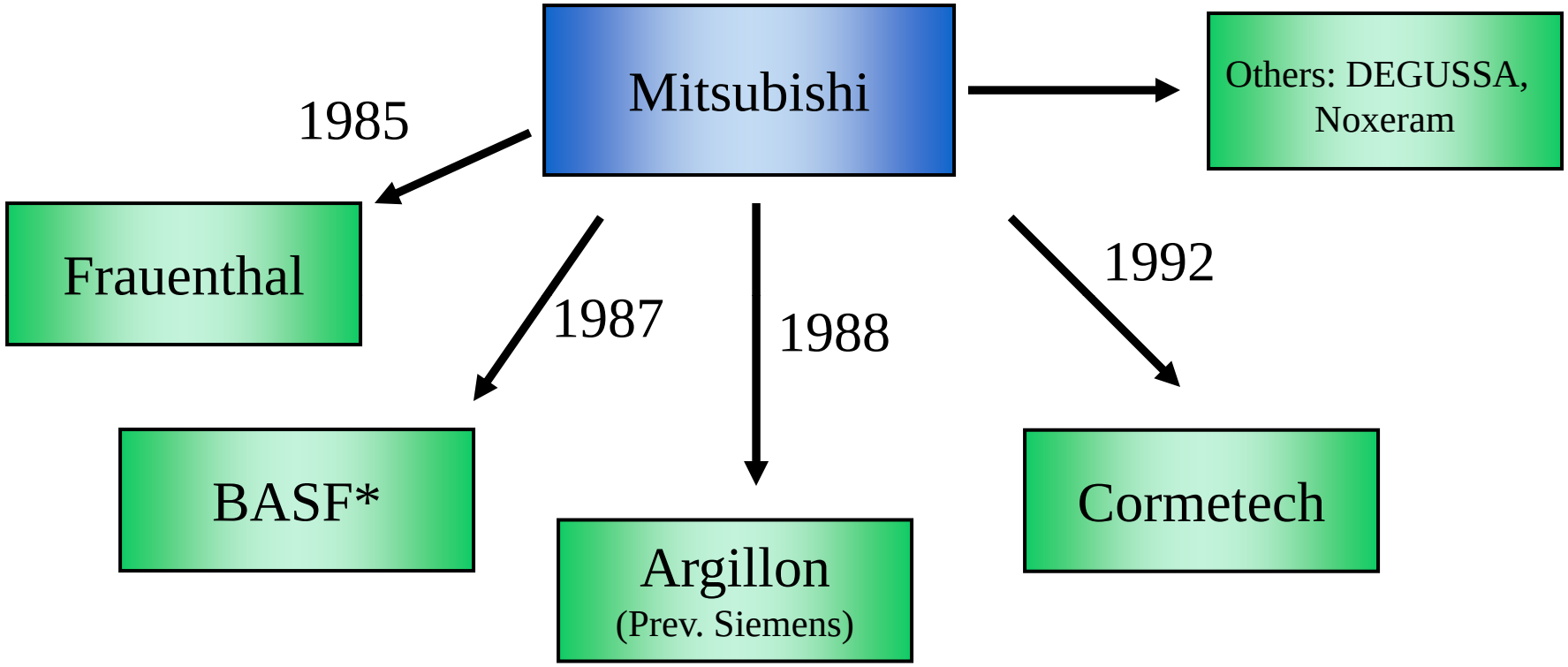
Mitsubishi

Information Provided to Licensees:

- Production Know How
- Two Catalyst Geometries (Pitch and Wall Thickness)
  - 7.5 mm (Coal and Oil)
  - 4.2 mm (Gas)
- Three Catalyst Recipes (Coal and High Sulfur Oil, Medium Sulfur Oil, Gas)

CERAM ENVIRONMENTAL, INC.

Mitsubishi Catalyst Licensees



CERAM's or Other European Licensee's Application Experience is **Not** Exchanged with Mitsubishi

*BASF Curtailed Catalyst Production in 1992 and Began Exclusive Distribution of CERAM Catalyst

CERAM ENVIRONMENTAL, INC.

CERAM Catalyst Innovations

CERAM

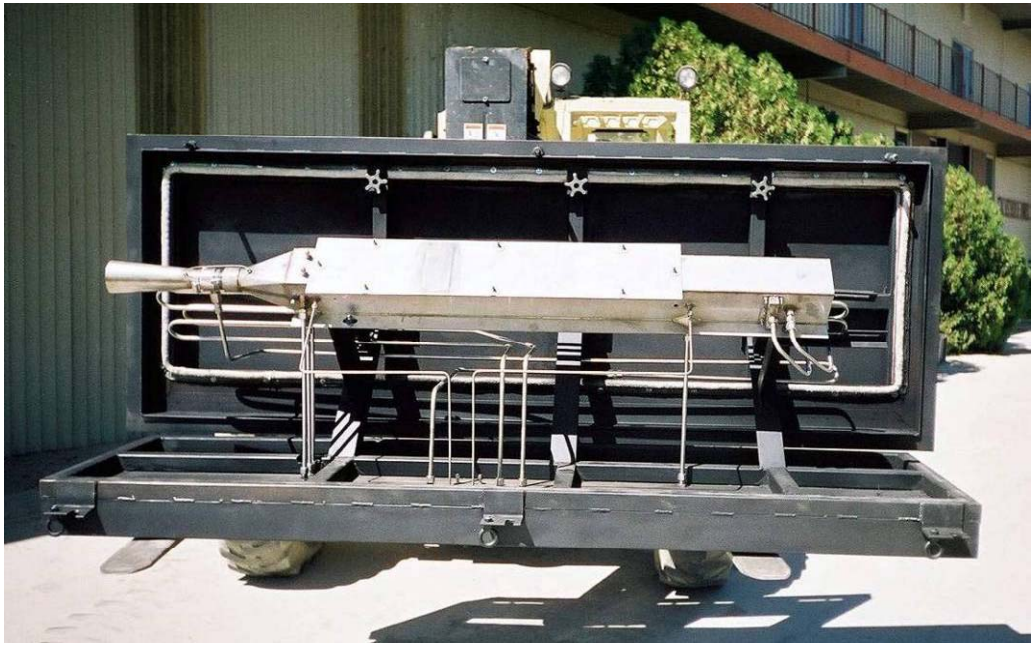
- More Than 30 Geometries
  - 1.7 mm Pitch to 11.3 mm Pitch
  - 0.3 to 1.4 mm Wall Thickness
- No Standard Formulations – Site Specifics Fully Accommodated
  - More Than 200 Chemical Formulations
- Widest Temperature Range in Industry (300 to 1,050 F)
- Lowest Oxidation/Highest Activity Catalyst in Industry
- Industry Leading Mechanical Life
  - >120,000 Operating Hours (Coal High Dust)
  - Up to 5 Regenerations/Rejuvenations (Coal High Dust)
- Diesel Truck DeNOx Catalyst

CERAM ENVIRONMENTAL, INC.

CoPilot® Catalyst Test Reactor

- Patented In-Situ Self Contained Catalyst Testing Apparatus
- In-Situ Reactor Allows for Catalyst Exposure to Actual Flue Gas Conditions Present
  - Fly Ash
  - Temperature
- Modulated Gas Flow Velocity to Match SCR Reactor Conditions
- Allows On-Line Insertion and Removal From Flue Gas – No Outage Required for Access

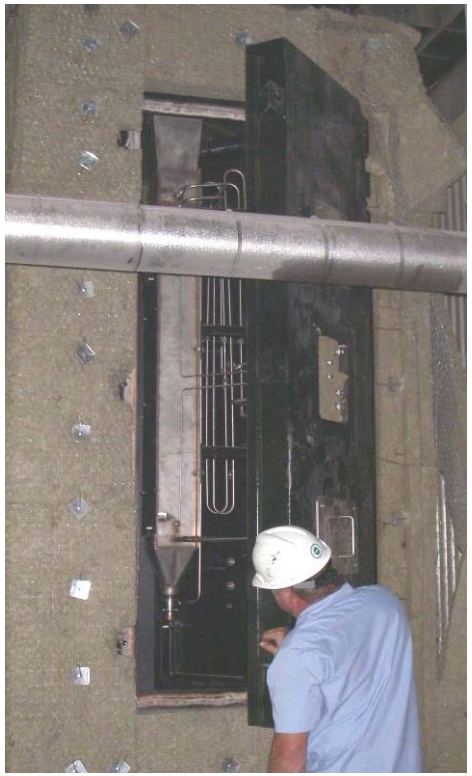
PROVEN ON 8 REFERENCES



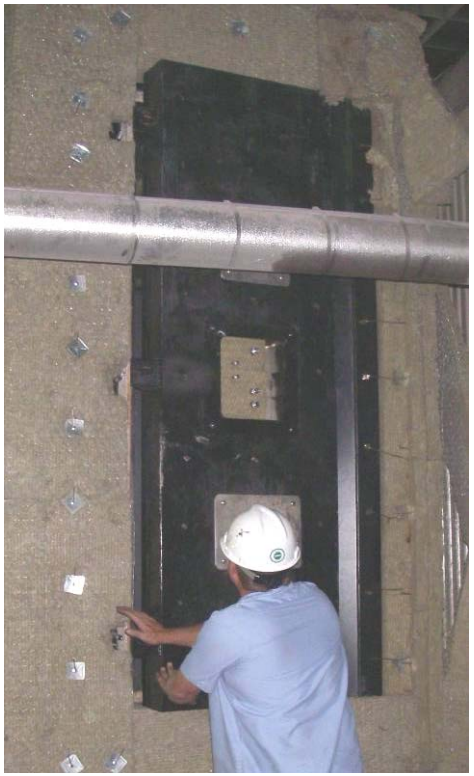
CERAM ENVIRONMENTAL, INC.

Door Operation

1. Open Door



2. Remove/Install Element



3. Close Door

CERAM ENVIRONMENTAL, INC.

CERAM Catalyst Designs for ND Lignite Ash

- High Sodium Concentrations in Ash
  - Sodium Aerosols are a Known Catalyst Poison
  - Critical to Consider Sodium Aerosols Present Downstream of ESP and Wet FGD
  - May Require Special Layup Protection
- Presence of Potassium in Ash
  - Similar to Biomass Applications, can be Accounted for in Catalyst Design Margin
- Presence of Pyrosulfates (Sodium, Iron, and Sulfur)
  - Can Cause Increase in SO_2 to SO_3 Conversion Rate Over Time
  - Concern Reduced with Low Dust or Tail End SCR
  - Can be Accounted for In Catalyst Design Margin

CERAM ENVIRONMENTAL, INC.

CERAM Catalyst Design for Low Dust SCR

Parameter	Units	M.R. Young Unit 1	M.R. Young Unit 2
Temperature	F	564	564
Catalyst Length	mm	1,275	1,180
Catalyst Pitch / Wall Thickness*	mm	4.9 (30 cell) / 0.55	4.9 (30 cell) / 0.55
Number of Reactors	-	2	2
Catalyst Modules/Layer	-	45 (5 x 9)	84 (7 x 12)
Catalyst Layers	-	2 + 1 Spare	2 + 1 Spare
NO_x Inlet / Outlet	ppmvd ref O_2	326 / 47.5	311 / 45.3
Pressure Drop (2 layers clean)	in. w.g.	3.0	2.6
SO_2/SO_3 Oxidation Rate	%	0.5%	0.5%
Minimum NH_3 Inject Temperature	F	540	540
Volume Per Reactor	m^3	186	321.5
Total Vol. (2 Reactors)	m^3	372	643

* Designed Mechanically for Regeneration/Rejuvenation

CERAM ENVIRONMENTAL, INC.

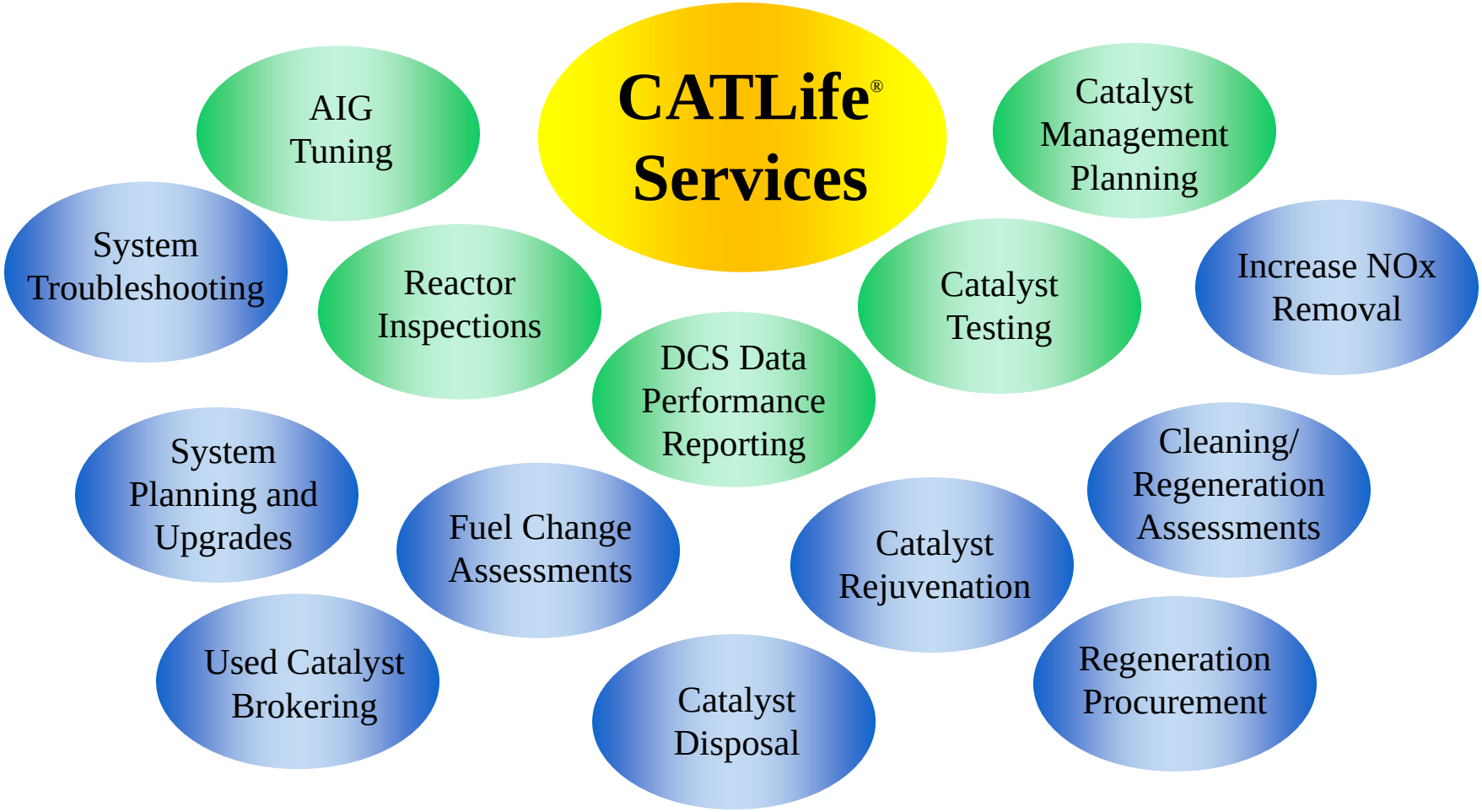
CERAM Catalyst Design for Tail End SCR

Parameter	Units	M.R. Young Unit 1	M.R. Young Unit 2
Temperature	F	562	562
Catalyst Length	mm	785	780
Catalyst Pitch / Wall Thickness*	mm	4.2 (35 cell) / 0.55	4.2 (35 cell) / 0.55
Number of Reactors	-	2	2
Catalyst Modules/Layer	-	45 (5 x 9)	77 (7 x 11)
Catalyst Layers	-	2 + 1 Spare	2 + 1 Spare
NO_x Inlet / Outlet	ppmvd ref O_2	286 / 41.6	278 / 40.5
Pressure Drop (2 layers clean)	in. w.g.	3.2	3.2
SO_2/SO_3 Oxidation Rate	%	0.6%	0.6%
Minimum NH_3 Inject Temperature	F	513	513
Volume Per Reactor	m^3	114.5	195
Total Vol. (2 Reactors)	m^3	229	390

* Designed Mechanically for Regeneration/Rejuvenation

CERAM ENVIRONMENTAL, INC.

CERAM's Comprehensive Catalyst and SCR System Management Services (CATLife®) Program



CERAM ENVIRONMENTAL, INC.

Bryant, Ronald

From: Wayne Jones [WSJ@topsoe.com]
Sent: Tuesday, August 18, 2009 3:14 PM
To: Bryant, Ronald
Cc: TNW@topsoe.com
Subject: RE: Update
Attachments: Scope of work and responsibility; Without Remedies 8-12-09.doc

Ron,

Please find attached the information you requested concerning our typical SCR system scope of work and our capabilities. Please review and let me know if you have any questions.

Still waiting on information about the start-up procedure for Amager and our comments to the NDA.

Regards,
Wayne

Wayne S. Jones
Sales Manager, Power Generation
Haldor Topsoe, Inc.
281-228-5136 (office)
281-228-5129 (fax)
281-684-8811 (cell)
wsj@topsoe.com
www.HaldorTopsoe.com

"Bryant, Ronald" <rbryant@burnsmcd.com>

08/17/2009 05:20 PM

To "Wayne Jones" <WSJ@topsoe.com>
cc
Subject RE: Update

Thanks for the update Wayne.

From: Wayne Jones [mailto:WSJ@topsoe.com]
Sent: Monday, August 17, 2009 4:42 PM
To: Bryant, Ronald
Cc: TNW@topsoe.com

Subject: Update

Ron,

I have finished the requested document defining HTI "typical" scope of work on similar projects. I should have that to you tomorrow. I'm shooting for our response to the NDA on Wednesday. I have a request in for any information available with respect to the start up of Amager Plant

Thanks,
Wayne

Wayne S. Jones
Sales Manager, Power Generation
Haldor Topsoe, Inc.
281-228-5136 (office)
281-228-5129 (fax)
281-684-8811 (cell)
wsj@topsoe.com
www.HaldorTopsoe.com

SCR Process Engineering Package
Scope of Work, Responsibilities, Battery Limits and Guarantees
8-14-2009

Haldor Topsoe, Inc. (HTI) has the capability of simply providing SCR catalyst in elements or modules or providing the catalyst along with a comprehensive process engineering package. For coal fired applications, HTI prefers to provide both the catalyst and process engineering package. This structure provides single point responsibility for the client and allows HTI to utilize our vast amount of experience to design a well integrated SCR system from the economizer outlet to the air heater inlet.

Please find a description below of what will be called HTI's "preferred" scope of work when process engineering tasks are included in our scope. With any project where more than one company is involved in the engineering, optimal points exist where it makes the most sense to draw battery limits where one company hands off responsibility to another. I will define these battery limits in detail.

While the primary engineering firm (AE) investigates available space, foundation constraints and structural steel and support requirements for the ducts, flues and reactor box. HTI will assist in the sizing of the reactor to provide the optimal gas velocity for the specific application. In addition, HTI will review preliminary ductwork layout drawings provided by AE to determine if any fatal flaws might exist with regard to meeting or exceeding all required flue gas conditions at the AIG. HTI does this review in coordination with and with the assistance of the flow modeling company, contracted by HTI and also includes an evaluation of the proposed ductwork configuration focusing on conditions that might create ash fallout issues in the ductwork or reactor.

HTI will also develop and provide recommended minimum requirements for all flow criteria that must be validated in the physical flow model paying particular attention to any characteristics of a specific application that might impact SCR system performance. For example, if very high NOx removal is required special attention might be given to NH_3 to NOx maldistribution at the catalyst face while if the fuels are very erosive and contain a high percentage of ash then gas velocity and angle of entry of the flue gas at the catalyst face might be emphasized.

Once the general arrangement is determined, a preliminary CFD model will be produced in parallel with the construction of a 1/12 scale physical model. HTI will work with the flow modeler throughout the construction and initial testing of the model. If early test results indicate problems with the initial ductwork design HTI will work with the AE and flow modeler to make necessary revisions while considering cost and constructability impacts.

Early in the process a decision will be made whether to use HTI's proprietary "Star Mixer" and AIG system or a Sulzer static mixer and their AIG design. If the HTI mixer is used then HTI will provide drawings for both the mixer and AIG assembly that contain all the detail necessary to generate fabrication drawings. In this case, HTI will also provide the design drawings for the support hardware necessary to install the "Star Mixers" and AIG inside the duct. The AE will be responsible for the procurement of the "Star Mixer", AIG and attachment hardware. The AE will also be responsible for designing the nozzle and flange assembly at the duct wall that will provide the penetration and support for the AIG lance to the duct wall. The battery limit on the AIG drawing is at the AIG lance pipe flange just outside the duct work lagging and everything upstream of that point is the responsibility of the AE.

If a Sulzer mixer is selected, then HTI will take on the responsibility of specifying and procuring both the flow model mixers (1/12 scale) and full scale mixers as well as the Sulzer designed AIG. Sulzer will design and supply all attachment and support hardware required for both the AIG assembly and static mixers.

As apart of the flow model effort, drawings will be provided for all flow conditioning devices including, if required, the large particle ash (LPA) screens. The drawings will provide all required information and dimensions to support the generation of fabrication drawings by the AE including location and orientation of the flow conditioning devices within the duct or reactor. The AE will be responsible for the detail design and support of all flow conditioning devices located either in the ductwork or reactor as well as the procurement of all flow conditioning devices except the Sulzer static mixers, attachment hardware and associated AIG assembly, as described above.

In some cases both the HTI "Star Mixer" and Sulzer mixer will be tried in the flow model. Based on preliminary results a final selection will then be made. At that time all remaining physical flow and CFD modeling will be preformed using only the selected mixer and AIG system.

Below is a list of deliverables typically provided with the process engineering package from HTI. Additions or deletions from the list are possible to meet the exact requirements of a particular project:

- Process flow diagram
- Engineering deliverable schedule
- Manufacturing schedule
- Quality program description
- Flow modeling including physical and CFD modeling services and final report
- Specification for catalyst cleaning system equipment
- Review of all engineering drawings related to the SCR system
- Drawings for all flow control devices including LPA screen and rectifier grid (attachment drawings and hardware, by AE)

- Drawings for "Star Mixer", attachment hardware and associated AIG system, issued by HTI

(or)

- Drawings for Sulzer static mixer, attachment hardware and associated AIG system, issued by Sulzer through HTI

- License for use of the “Star Mixer” and AIG system
- SCR catalyst module drawings
- SCR catalyst bed dust deflection and module sealing system drawings
- SCR catalyst module lifting yoke drawings
- Catalyst arrangement plan
- Operating procedures for installation of catalyst and operations of the SCR
- Operating procedure for handling and storage of the catalyst
- Special tools list
- Performance test procedure
- Performance curves

HTI can also provide, if required, the following scope of services.

- P&ID, preliminary
- SCR ammonia control system specification
- Ammonia system specification

The following are the process guarantees that HTI typically provides as a part of the process design package.

- SCR system pressure drop from the economizer outlet to the air heater inlet. More specifically the pressure drop includes all ductwork and reactor box included in the physical flow model. A target pressure drop will be provided prior to the completion of the physical flow model followed by the actual pressure drop guarantee after the model is complete.
- Flue gas velocity maldistribution at the AIG, at the catalyst face, and air heater inlet
- Flue gas temperature maldistribution at the AIG and catalyst face
- NH_3 to NOx maldistribution at the AIG and catalyst face
- Flue gas angle of entry at the catalyst face
- Minimize ash deposition as per the physical flow model
- Catalyst life
- NOx removal efficiency
- Ammonia slip
- Ammonia usage
- SO_2 oxidation rate
- Mercury oxidation rate

Bryant, Ronald

From: Wayne Jones [WSJ@topsoe.com]
Sent: Wednesday, August 19, 2009 9:19 AM
To: Bryant, Ronald
Cc: lkvernen@minnkota.com; Blakley, Robert; TNW@topsoe.com
Subject: Fw: Startup procedure for Amager Unit 1
Attachments: AMV1 Start-up meeting July 2008.pdf

Ron,

Please find a powerpoint presentation below discussing the proposed startup procedure for Amager 1. They plan to use heated air to preheat the SCR prior to the introduction of flue gas. The stream/gas heater will be used to preheat the air. Let me know if you have any questions.

Regards,
Wayne

Wayne S. Jones
Sales Manager, Power Generation
Haldor Topsoe, Inc.
281-228-5136 (office)
281-228-5129 (fax)
281-684-8811 (cell)
wsj@topsoe.com
www.HaldorTopsoe.com

----- Forwarded by WSJ/houadm/hti on 08/19/2009 09:15 AM -----

trs/CAT/RVN/Haldor Topsoe@HTAS

To Wayne Jones@hti
cc Hans Jensen-Holm [HAJH]@htas, Nate White@hti

08/19/2009 04:04 AM

Subject Re: Startup procedure for Amager Unit 2 Link

Wayne,

Condensing of water during start-up is definitely a serious problem with the high content of Na in the ash.

In Amager 2 this problem is solved by a steam-gas heater, please refer to page 6 in the attached file. The plant is preheated by air and the steam-gas heater just before the SCR gives a "dry" heating of the gas.

Best regards
Torben

Wayne Jones@hti

18-08-2009 22:58

Phone: 281-228-5136

Location: Houston

To Hans Jensen-Holm [HAJH]@htas, Torben Slabiak [TRS]@htas

cc Nate White@hti

Subject Startup procedure for Amager Unit 2

Gentlemen,

We have been discussing with Minnkota Power the possibility of installing a SCR either downstream of a cold ESP or wet scrubber on a North Dakota lignite fired cyclone boiler. As you may recall, this fuel contains a high level of alkali material (as high as 6-9% Na) in the fuel. The fuel also has very high levels of CaO (~20%). The concern is that the high CaO coupled with the high Na will produce a very fine and extremely sticky fly ash. My understanding is that Amager 2 has a tail end SCR. We were discussing possible operational issues surrounding the startup of Amager due to the high levels of alkali poisons in the biomass fuel and whether a full/partial bypass around the SCR may have been installed.

The flue gas on the lignite unit will be reheated using NG or other heat source. During startup if the reactor and catalyst are cold and covered with fly ash the initial flue gas entering the SCR will be rather cool and upon hitting the surface of the catalyst and catalyst modules water is likely to condense on the surface providing a path for the Na to enter the catalyst pore structure. We assumed that Amager might have a similar issue and may have installed a bypass to allow for the heat up of the flue gas before passing it through the reactor.

Any ideas or comments are appreciated.

Thanks,
Wayne

Wayne S. Jones
Sales Manager, Power Generation
Haldor Topsoe, Inc.
281-228-5136 (office)
281-228-5129 (fax)
281-684-8811 (cell)
wsj@topsoe.com
www.HaldorTopsoe.com

AMV1 Start-up of flue gas cleaning

Meeting with API and HTAS 16.07.2008

Henrik Rostgaard
Chemistry & Materials

© Vattenfall AB

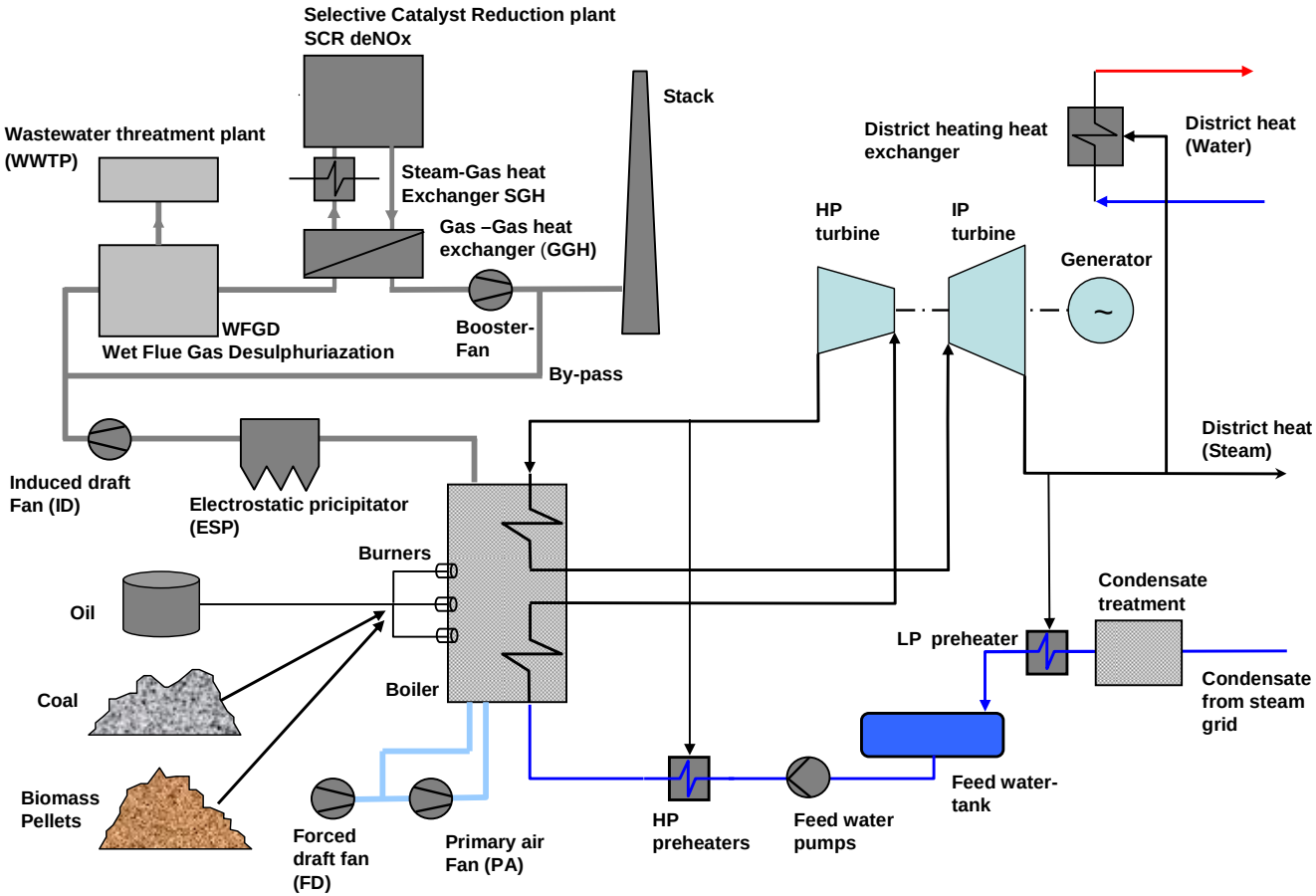
VATTENFALL

Agenda

1) Presentation
2) Introduction
3) Start and stop of Flue Gas Cleaning
4) Stand still
5) Experience from start up unit 3
6) Discussion and comments from API and HTAS
7) Miscellaneous

© Vattenfall AB

Introduction to Amager Power Station unit 1



© Vattenfall AB

VATTENFALL

Introduction – fuels and Flue Gas Cleaning

Fuels

Biomass	–	Flue gas cleaning is not necessary
Coal/biomass	–	Flue gas cleaning will be used
Coal	–	Flue gas cleaning will be used
Oil	–	Only for start-up, but flue gas cleaning will be used if coal-firing is planned

© Vattenfall AB

Start and stop of flue gas cleaning

1) Start-cases

Cold start of boiler

Hot start

Shift from biomass to coal

2) Stop-cases

Stop of boiler

Shift from coal to biomass

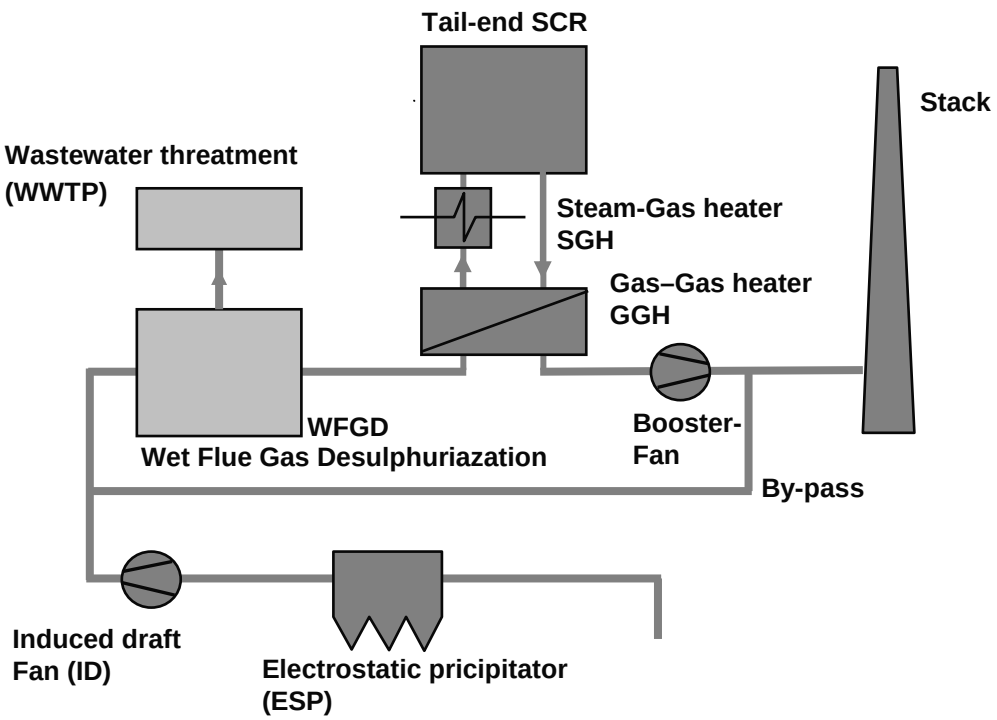
3) Stand-still

During biomass-firing

During overhaul and summer-stop

© Vattenfall AB

Flue gas cleaning AMV1



Cold start

Boiler, ESP, flue gas ducts, FGD and SCR are pre-heated with air

Heating air before FGD below 45 degree C

Air from the boiler will pass through FGD to the gas/gas heater, steam/gas heater and SCR.

The scrubber liquid is mixed by the hydrocyclone pumps, but the oxidation air is not injected.

The steam/gas heater is operated to give a temperature increase of the SCR of 50 degree C or more pr. hour.

© Vattenfall AB

Cold start

Heating air before FGD above 45 degree C

- Oxidation air is injected to start circulation of the scrubber slurry
- SGH is operated to give a temperature increase of the SCR of 50 degree C or more pr. hour.
- When the temperature of the heating air is 110 degree C before FGD <u>and</u> 65 degree C after SCR, the first oilburner will be ignited.
- Subsequently more oilburners will be ignited and the switch to coal-firing will be done as quick as possible.

© Vattenfall AB

Cold start

- During both steps the bypass duct will be closed.
- GGH will always be colder than the SCR.
- The above mentioned procedure will ensure that the temperature of the SCR always is above the water dew point.

© Vattenfall AB

Hot start

As second part of cold start

© Vattenfall AB

VATTENFALL

Shift from bio-mass to coal

The procedure for the boiler is not finalized:

Maybe a complete stop is necessary – maybe not.

If a complete stop is not needed, preheating of SCR will not be possible, but GGH will always be colder than SCR.

© Vattenfall AB

Stops and standstill

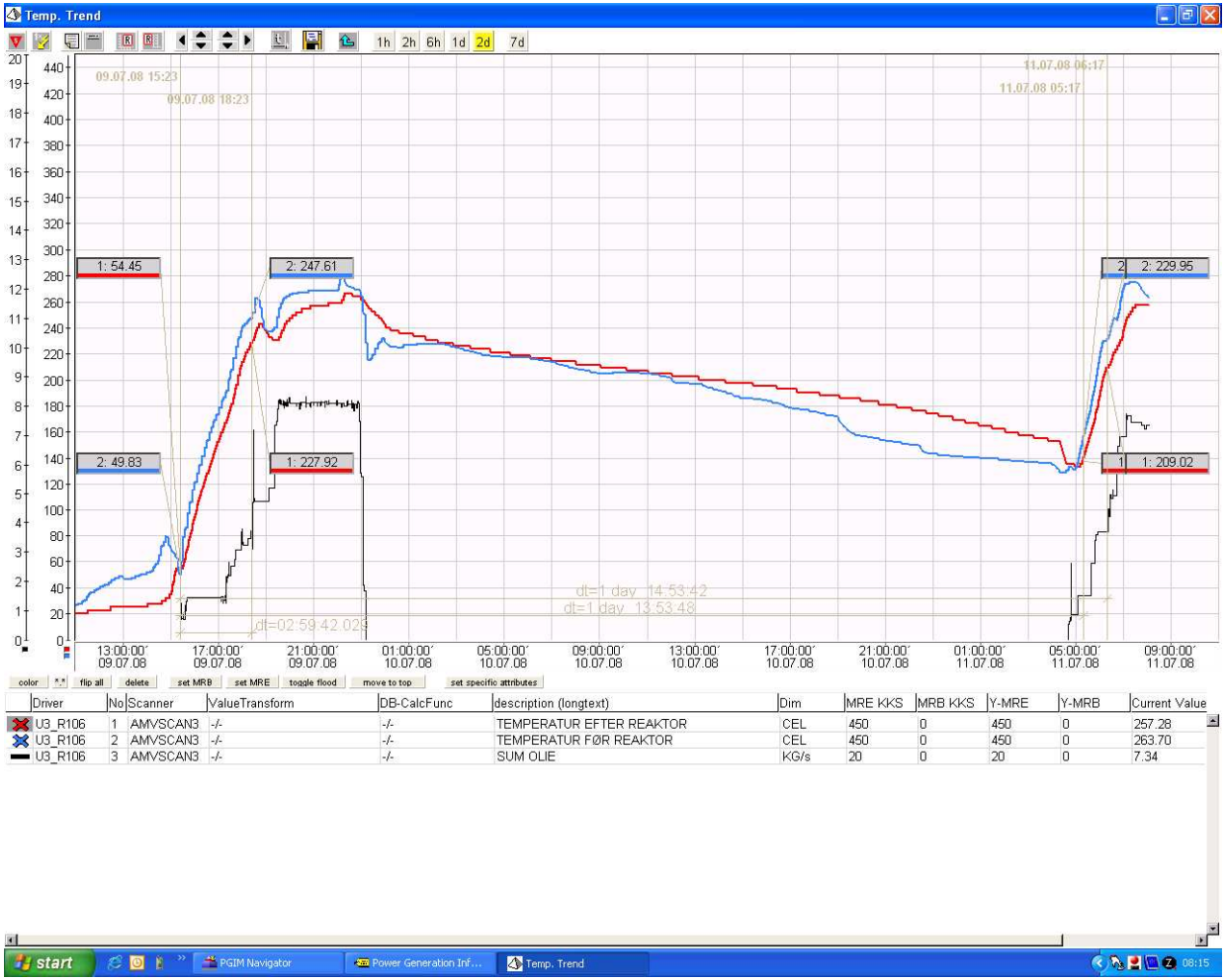
Stop of boiler
No problem – flue gas cleaning will be flushed with air during stop procedure

Shift from coal to biomass
Flue gas cleaning could be left with ”old” flue gas during bypass operation of the boiler.

Stand-still
During biomass-firing – Possibly 3 x 1 month
During overhaul and summer-stop – 3 months

© Vattenfall AB

Start up unit 3 on 09.07.2008



© Vattenfall AB

VATTENFALL

Thank you!

Comments and questions?

© Vattenfall AB

VATTENFALL

Bryant, Ronald

From: Bryant, Ronald

Sent: Wednesday, August 26, 2009 4:26 PM

To: Wayne Jones

Cc: 'lkvernen@minnkota.com'; John Graves; Craig Bleth (cbleth@minnkota.com); Gerry Pfau (gpfau@minnkota.com); Andy Freidt; Weilert, Carl; Blakley, Robert; sbenson@undeerc.org; 51684

Subject: Minnkota SCR Catalyst Recommendations

Attachments: Scope of Services 26Aug09.doc; Report 1084 - Particulate - FINAL 8-20-09.pdf; MRY SCR Vendor Query (4-18-07) - Abbreviated.pdf

Wayne

Minnkota Power is requesting recommendations on SCR catalyst design for low-dust and tail-end applications as discussed in your offices on August 10.

Attached are the following documents for your consideration:

1. Scope of Services 26Aug09
2. Report 1084 - Particulate - FINAL 8-20-09
3. MRY SCR Vendor Query (4-18-07) – Abbreviated

The first document summarizes items Minnkota Power is requesting in support of the required BACT.

The second document is flue gas testing data performed at the Milton R. Young Station. This information should be treated confidential.

The third document includes some basic boiler operating parameters and was extracted from the MRY SCR Vendor Query originally transmitted in April of 2007.

Please contact us if you need any additional information or would like to discuss the project.

Thank you for your assistance.
Ron Bryant
816-822-3023

Scope of Services
SCR Catalyst Recommendations

Minnkota Power Cooperative
Milton R Young Station
August 26, 2009

1. Minnkota Power Cooperative (MPC) operates two coal-fired electric generating units at the Milton R. Young Station. Both units are Babcock & Wilcox balanced-draft cyclone fired boilers burning 100% North Dakota lignite coal supplied from an adjacent mine. Unit 1 has a gross design output capacity of 257 MW and was initially placed into commercial service in 1970. Unit 2 has a gross original design output capacity of 477 MW and was initially put into service in 1977. The units are located approximately 40 miles northwest of Bismarck, ND.

2. MPC is performing a SCR cost estimate for both units as part of a NO_X BACT Study required by the North Dakota Department of Health. Because of the unique characteristics of North Dakota lignite, MPC is requesting assistant with SCR catalyst selection and sizing.

3. The scope of services MPC is requesting includes the following for both low dust and tail end SCR applications for both units:

    a. Size the reactors to provide the optimal gas velocity and NO_X reduction for the specific applications.

    b. Provide anticipated guarantees for NO_X reduction for the specific applications. Nominal anticipated NO_X concentration entering the reactors is 0.5 lb/million Btu. Nominal desired maximum NO_X concentration exiting the reactors is 0.05 lb/million Btu.

    c. Provide anticipated guarantees for ammonia usage and ammonia slip for the specific applications. The maximum ammonia slip should not exceed 5 ppm.

    d. Provide anticipated guarantees for catalyst deactivation rate and life (number of operating hours between catalyst replacement). It is desired to have a 3 year interval between catalyst layer change-out. If a 3 year interval is not achievable, provide the longest interval the catalyst vendor is able to guarantee.

    e. Provide budgetary pricing for the recommended catalyst.

    f. Review preliminary ductwork layout drawings to determine if any fatal flaws are apparent.

4. Additional design parameters and flue gas testing results are included as an attachment. It is the intent that Dr. Steve Benson and other team members will discuss the test data and related implications of the catalyst selection and design with the catalyst supplier.

5. Please provide requested items by September 18, 2009.

FINAL REPORT:

ASSESSMENT OF PARTICULATE CHARACTERISTICS UPSTREAM AND DOWNSTREAM OF ESP AND WET FGD

Prepared for:

Andrew Freidt
Permit and Compliance Engineer
Minnkota Power Cooperative, Inc.
Milton R. Young Power Station
Center, ND

Prepared by:

Margaret Laumb, Research Engineer and
Steve Benson, President
Microbeam Technologies, Inc.

John Kay and
Don McCollor
UND Energy and Environmental Research Center

Frank Bowman and
Dennis Sisk
UND Chemical Engineering

July 1, 2009

Shipping:
4200 James Ray Drive, Ste. 191
Grand Forks, ND 58203

Mailing:
PO Box 14758
Grand Forks, ND 58208-4758

Phone: 701-777-6530
Fax: 701-777-6532
info@microbeam.com

EXECUTIVE SUMMARY

Particulate sampling was conducted at Minnkota Power Cooperative's Milton R. Young plant to determine the particulate size and composition distribution of samples collected upstream of the ESP, upstream of the wet scrubber, and downstream of the wet scrubber. Emphasis was placed on determining the fate of sodium, potassium, and calcium since these elements can cause significant plugging and deposition problem.

During the testing, operating conditions of the plant were constant and there was no gas bypass. The coal fired during the testing remained relatively consistent. The as-received ash content ranged from 7.73 to 7.89%. Sodium oxide content of the ash ranged from 7.22 to 7.57% and the base-to-acid ratio decreased the last two days of testing (a result of a decrease in CaO content and an increase in SiO_2 and Al_2O_3 levels). Sampling upstream of the ESP and scrubber were conducted using a combination multicylones and impactors. The cyclones collected sized fractions of larger particles (greater than one to five microns) and the impactor collected the sub-micron particulate. Sampling downstream of the scrubber was conducted with a single cyclone followed by a 13-stage advanced impactor. In addition, the submicron particle number concentration was measured using a scanning mobility particle sizer (SMPS).

The results of the particulate mass information indicated a high loading at the ESP inlet of 4.96×10^6 µg/dscm, a scrubber inlet loading of 1.1×10^4 µg/dscm, and a scrubber outlet loading of 1.08×10^4 µg/dscm. These results show very little overall removal of the submicron particulate across the wet scrubber system. A significant fraction of the particulate was removed by the ESP, with a removal efficiency of 99.76%.

The size distribution of the particulate collected upstream of the ESP and upstream of the scrubber was multi-modal as summarized below:

- Upstream of the ESP there were at least three modes – a larger mode at 40 to 50 µm, a second mode at just under 10 µm, and third mode at about 1 µm. The larger particles are typically derived from mineral grains in the coal such as quartz, clays, and pyrite. The intermediate-sized particles are typically derived from small minerals and organically associated elements. The smaller mode (about one-micron and smaller) contains fine particles and condensed vapor phase species.
- Upstream of the scrubber there were two distinct modes – a larger mode between 8 to 10 µm and another mode centered at about 1 to 2 µm in diameter. The smaller mode is typically condensed vapor phase and small particles.
- Downstream of the scrubber, the primary mode centered at about 0.5 to 0.7 µm, and another possible mode occurred at 3 µm and larger.
- Particle number distributions were as follows:
    - Inlet to the ESP – between 1×10^7 to 10^8 particles per dry normal cubic centimeter (dncc);
    - Inlet to the scrubber is 10^5 particles/dncc;
    - Outlet of the scrubber 7×10^5 particles/dncc.

- Particle number distributions into the nanometer scale (1 μm = 1000 nm) was found to be as high as 10^5 particles/dncc.

Particle composition distributions of the particulate were determined for each of the major elements. The results were reported as μg/dscm of the element as illustrated in the Appendix and in the figures in the text.

- Upstream of the ESP the composition trends for sodium, potassium, calcium and sulfur showed greater concentrations of these elements in the particles that are smaller than 10 μm, with a significant increase in concentration in the flue gas at a particle size of less than 2 μm. There is another increase at 0.1 μm.
- Upstream of the scrubber the compositional trends for sodium, potassium, calcium and sulfur show higher levels at the 1 μm level. The ESP was effective in removing larger-sized particles, as well as some of the 0.1 μm particles. However, in the intermediate 1 μm particles, the ESP is not as effective in removing the particles.
- Downstream of the scrubber the composition size distribution determined for sodium, potassium, calcium and sulfur showed significant levels of sodium and sulfur in size fraction finer than 1 μm. The DLPI sampling system provides very accurate sizing data in the submicron size range. Other elements such as aluminum, silicon and iron show a significant depletion below 1 μm.

Comparison of the characteristics of the particles in terms of mass and composition indicate that, at the time of the testing, the total average mass of the particulate was about 10,800 μg/dscm. The particulate consisted mainly of sodium, potassium, and sulfur. The total quantity of sodium and potassium exiting was between 2000 to 3000 μg/dscm.

INTRODUCTION AND BACKGROUND

Microbeam Technologies, Inc. (MTI) teamed with Energy & Environmental Research Center (EERC) and the Chemical Engineering Department at the University of North Dakota (UND-ChE) to determine the abundance and composition of particulate materials produced at Unit #2 of Minnkota Power Cooperative's Milton R. Young Station (MRY), equipped with an electrostatic precipitator (ESP) and a wet flue gas desulfurization (FGD) system.

Very small particles or aerosols are produced upon combustion of all fuels. These particles have diameters less than ten microns, and in many cases less than one micron. They are formed during the combustion process - when the fuel is exposed to high temperatures and gaseous environments, impurities within the fuel are vaporized. When the gas is cooled, the vaporized species condense to form the small particles or aerosols.

Abundance and composition of the aerosols vary depending upon the fuel type and the combustion system. High-temperature combustion systems, such as cyclone-fired systems, produce higher levels of vaporized species than other combustion system types. Fuels (such as biomass or lignite) that contain high levels of alkali (sodium and potassium) and alkaline earth elements (calcium and magnesium) are especially likely to produce abundant aerosols in the cooler regions of combustion systems, such as air pollution control systems.

Collection of aerosol particles finer than five- to ten-microns in electrostatic precipitators and scrubbers is difficult because physical processes used by these technologies to capture particles are very limited in the one-tenth to five-micron size range. Detailed discussion of the processes can be found in the appendix of this report.

This report contains the results of analyses performed on coal and ash samples collected during field testing at MRY Unit 2. The work was performed to determine the properties (including size, mass, and composition) of particulates collected upstream and downstream electrostatic precipitator and wet FGD.

GOALS AND OBJECTIVES

Objectives of the project were as follows: 1) obtain representative, size-segregated samples of particulate material, including super- and sub-micron particulate, from three locations; 2) perform analyses on these samples to determine the size, mass, and composition distribution; and 3) provide an assessment of the probable impact of particulate inorganic species on the performance of NO_x reduction technologies.

SAMPLE COLLECTION AND CHARACTERIZATION

Sampling

Particulate material in the flue gas was collected and measured upstream and downstream of the MRY electrostatic precipitator, also denoted as the "air heater inlet" and at the wet flue gas desulfurization (FGD) or "scrubber inlet". Multi-cyclone samples were taken at the locations

during the impactor testing. Sampling at the ESP inlet and scrubber inlet were conducted at single port locations and traversed for depth. The sampling at the ESP inlet was performed using two different ports; the total sampling time was divided equally between the selected sampling depths. The sampling depths, along with a summary of sampling activities, are summarized in **Table 1**. Sampling locations are shown on a simplified schematic in **Figure 1**.

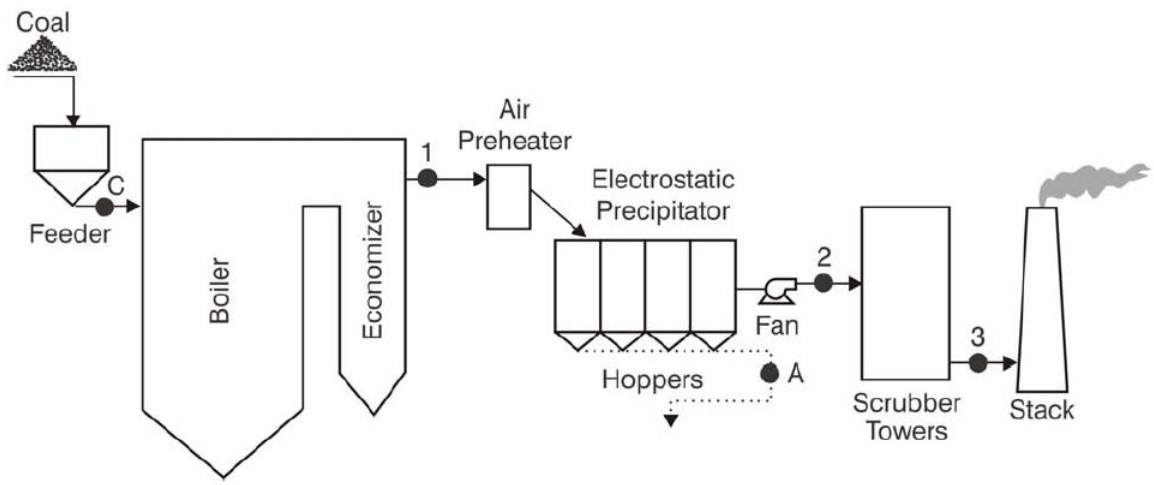


Figure 1. Location of sampling points at MRY Unit 2.

Table 1. Summary of sampling activities at MRY Unit 2.

Test	Location	Date	Start Time	End Time	Duration (minutes)	Sampling Depth (inches)	Notes
IMP/MC Test #1	ESP inlet	3/17/2009	15:40	16:23	43	56,112,161	Figure 1 – point 1
IMP/MC Test #5	ESP inlet	3/19/2009	13:37	13:49	12	56,112,168	Figure 1 – point 1
IMP/MC Test #2	ESP outlet/B scrubber inlet	3/16/2009	16:35	18:13	98	48,102,161	Figure 1 – point 2
IMP/MC Test #3	ESP outlet/B scrubber inlet	3/17/2009	13:47	15:47	120	48,102,161	Figure 1 – point 2
IMP/MC Test #4	ESP outlet/B scrubber inlet	3/18/2009	13:00	15:00	120	48,102,161	Figure 1 – point 2
IMP/MC Test #6	ESP outlet/B scrubber inlet	3/19/2009	12:20	14:20	120	48,102,161	Figure 1 – point 2
SMPS	B Scrubber outlet	3/18/2009			240	~84	Figure 1 – point D
SMPC	B Scrubber outlet	3/19/2009			240	~84	Figure 1 – point D
Dekati "SEM"	B Scrubber outlet	3/18/2009	16:30	17:30	60		*Not weighed* Figure 1 – point D
Dekati Run #1	B Scrubber outlet	3/18/2009	22:00	23:15	75		Figure 1 – point D
Dekati Run #2	B Scrubber outlet	3/19/2009	13:00	16:00	180		Figure 1 – point D
Sample	**Location**	**Date**	**Time Collected**			**Notes**	
ESP ash sample	3B1 - row 1	3/19/2009	14:00			Figure 1 – point A	
ESP ash sample	3B2 - row 2	3/19/2009	14:00			Figure 1 – point A	
ESP ash sample	3B3 - row 3	3/19/2009	14:00			Figure 1 – point A	
ESP ash sample	3B4 - row 4	3/19/2009	14:00			Figure 1 – point A	
Coal sample	Feeder 1	3/16/2009	17:05			Figure 1 – point C	
Coal sample	Feeder 6	3/16/2009	17:10			Figure 1 – point C	
Coal sample	Feeder 7	3/16/2009	17:15			Figure 1 – point C	
Coal sample	Feeder 12	3/16/2009	17:00			Figure 1 – point C	
Coal sample	Feeder 1	3/17/2009	14:40			*Labeled 13:40 - Assumed to be 14:40* Figure 1 – point C	

Sample	Location	Date	Time Collected	Notes
Coal sample	Feeder 6	3/17/2009	14:50	Figure 1 – point C
Coal sample	Feeder 7	3/17/2009	14:55	Figure 1 – point C
Coal sample	Feeder 12	3/17/2009	14:30	Figure 1 – point C
Coal sample	Feeder 1	3/17/2009	17:55	Figure 1 – point C
Coal sample	Feeder 6	3/17/2009	18:00	Figure 1 – point C
Coal sample	Feeder 7	3/17/2009	18:30	Figure 1 – point C
Coal sample	Feeder 12	3/17/2009	17:50	Figure 1 – point C
Coal sample	Feeder 1	3/18/2009	14:10	Figure 1 – point C
Coal sample	Feeder 6	3/18/2009	16:25	Figure 1 – point C
Coal sample	Feeder 7	3/18/2009	16:15	Figure 1 – point C
Coal sample	Feeder 12	3/18/2009	14:00	Figure 1 – point C
Coal sample	Feeder 1	3/18/2009	19:50	Figure 1 – point C
Coal sample	Feeder 6	3/18/2009	19:45	Figure 1 – point C
Coal sample	Feeder 7	3/18/2009	19:45	Figure 1 – point C
Coal sample	Feeder 12	3/18/2009	19:50	Figure 1 – point C
Coal sample	Feeder 1	3/19/2009	14:15	Figure 1 – point C
Coal sample	Feeder 6	3/19/2009	14:30	Figure 1 – point C
Coal sample	Feeder 7	3/19/2009	14:20	Figure 1 – point C
Coal sample	Feeder 12	3/19/2009	14:10	Figure 1 – point C

Multicyclone Sampling

Size-fractionated fly ash samples were collected with a Southern Research Institute multi-staged multi-cyclone placed in the duct work at the air heater inlet (ESP inlet). The multicyclone consists of five cyclones, with decreasing d50 cut points, placed in series. The d50 particle size for each test is determined by the temperature and gas flow rate through the cyclone. For the testing at the MRY station, three of the five cyclone stages were used, along with the impactor, to collect selected coarser and finer fractions simultaneously. Size cut data for the multicyclone sampling performed at the air heater inlet are shown in **Table 2**.

Impactor Sampling

Size-fractionated fly ash samples were collected with a University of Washington seven-stage impactor placed in the gas stream behind the three multi-cyclone stages at the ESP inlet, and was used without multi-cyclone stages at the ESP outlet/scrubber inlet sampling location. The impactor is a round hole, multiple jet-type impactor with seven stages and a backup filter. Each stage has a decreasing d50 cut point. The d50 particle sizes for each test are determined by temperature and gas flow rate through the impactor. Cut points for the impactor at the air heater inlet are shown in **Table 2**. Cut points for the impactor at the scrubber inlet are shown in **Table 3**.

Table 2. D50 cut points for sampling (multicyclone and impactor) at the air heater inlet.

03/17/2009			3/19/2009		
Stage	Mass, g	d_{50} Cut Point, µm	Stage	Mass, g	d_{50} Cut Point, µm
Multicyclone			Multicyclone		
1	1.45614	9.70	1	0.49872	9.61
3	0.21646	4.07	3	0.05665	4.02
4	0.07816	2.58	4	0.02363	2.55
Impactor			Impactor		
1	0.00178	14.24	1	0.00051	14.13
2	0.00482	10.77	2	0.00179	10.69
3	0.01474	3.95	3	0.00542	3.92
4	0.02174	2.31	4	0.00624	2.286
5	0.05468	1.33	5	0.00769	1.31
6	0.03949	0.58	6	0.01154	0.57
7	0.03260	0.14	7	0.01136	0.13
Filter	0.04926	–	Filter	–	–

Table 3. D50 cut points for sampling (impactor) at the B scrubber inlet.

	03/16/2009		03/17/2009		03/18/2009		03/19/2009	
Impactor Stage	Mass, g	d_{50} Cut Point, µm	Mass, g	d_{50} Cut Point, µm	Mass, g	d_{50} Cut Point, µm	Mass, g	d_{50} Cut Point, µm
1	0.00228	13.54	0.00105	12.99	0.00555	13.06	0.00534	13.04
2	0.00503	10.22	0.00345	9.80	0.00337	9.85	0.00358	9.83
3	0.00183	3.81	0.00224	3.65	0.00278	3.67	0.00195	3.66
4	0.00192	2.03	0.00326	1.92	0.00259	1.93	0.00191	1.93
5	0.00336	1.15	0.00410	1.07	0.00311	1.08	0.00278	1.08
6	0.00110	0.54	0.00174	0.45	0.00146	0.50	0.00145	0.50
7	–	0.17	–	0.16	–	0.16	–	0.16
Filter	0.00008	–	–	–	–	–	–	–

DLPI Sampling

The Dekati Low Pressure Impactor (DLPI) is a state-of-the-art 13-stage cascade impactor for measuring gravimetric particle size distribution of very small particles. It size-classified particles from 10 microns (µm) to 30 nm, and a filter stage accessory enables collection of particles smaller than 30 nm in diameter. **Figure 2** shows the impactor and stages. The d50 cut points for sampling with the DLPI are shown in **Table 4**.

Figure 2. Dekati Low-Pressure Impactor.

Table 4. D50 cut points for sampling (Dekati Low Pressure Impactor) at the B scrubber outlet.

Stage #	$D_{50\%}$ [1] (μm)
13	10
12	6.8
11	4.4
10	2.5
9	1.6
8	1
7	0.65
6	0.4
5	0.26
4	0.17
3	0.108
2	0.06
1	0.03

[1] $D_{50\%}$ is the particle diameter where half of these particles pass through the stage and half are captured by the stage.

SMPS Sampling

Sampling at the scrubber outlet was conducted utilizing the scanning mobility particle scanning (SMPS) system that consists of an electrostatic classifier (EC), a condensation particle counter (CPC), and data analysis center (DAC). A schematic of the system is shown in **Figure 3**. The EC classifies the particles, and the concentration is measured by the CPC. The DAC includes a personal computer with custom software, which controls individual instruments and performs data reduction. The components of the SMPS system, particularly the CPC, function normally at about 35°C (95°F). However, the EC does not appear to be too sensitive to temperature conditions.

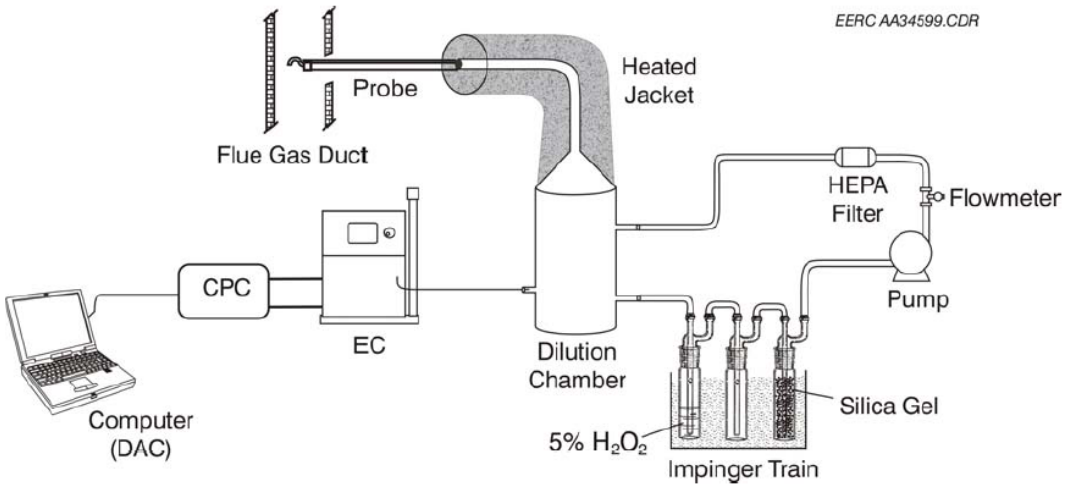


Figure 3. Schematic of the scanning mobility particle scanning (SMPS) system used at the B scrubber outlet.

The procedure for making particulate measurements with the SMPS system is conceptually simple, although manipulating the entire system is quite complex. Typically, flue gas enters the dilution chamber and is mixed with excess air fed through an external pump and at the flow rate of about 45–50 liters per minute (lpm). Dilution air from the pump passes through a HEPA filter to remove any particles that may be in the air. Part of the dilution air is sucked back from the dilution chamber and passed through an impinger train; the wet impinger contains about 250 milliliters (mL) of a 5% hydrogen peroxide (H_2O_2) solution, and the air is dried by passing it through a silica gel flask. The air from the flask is circulated through the pump back to the dilution chamber, and the recirculation process continues for the duration of the measurement. At the bottom of the dilution chamber, a ¼-inch line extracts a sample of the diluted flue gas and delivers it to the EC. The flow rates and pressure drop used in the EC are shown in **Table 5**.

Table 5. Electrostatic classifier (EC) flow meter set points.

Parameter	Monodisperse Air	Sheath Air	Excess Air
Flow Rate, lpm	0.3	3	3
Output, volts	2.305	2.735	2.627
Pressure Drop, cm H_2O	9	N/A*	N/A

* Not applicable.

Measurement does not begin until the CPC is running normally and flow is stable. At a typical working temperature of about 35°C (95°F), indicator lights are checked to ensure all parts are functioning properly (including the liquid level, laser, optics, pump flow, condenser, and saturator). The liquid used in running the CPC is n-butyl alcohol (n-butanol).

Analysis

Table 6 contains a full list of the samples collected and analyses performed. Samples collected were analyzed to determine chemical composition. Scanning electron microscopy with

x-ray elemental analysis was performed on the ash samples. Information gained from this method included images and point and area (average) analyses. This type of analysis is called "morphology" because it combines image analysis for features of interest with chemical analysis.

The multicyclone samples were analyzed using bulk chemical anlaysis at EERC. The bulk analysis involved microwave digestion of the ash followed by inductively-coupled plasma-mass spectrometry (ICP-MS). Concentrations of the major elements sodium, potassium, phosphorus, calcium, magnesium and iron were determined.

The coal samples collected during the tests were composited for standard ASTM tests (proximate and ash composition or "mineral ash" analysis) and for computer-controlled scanning electron microscopy (CCSEM) analysis, which provides information on mineral types, abundance, and sizes within the coal.

Table 6. List of samples and analyses performed.

Sample #	Date	Sample	Sample Location	Analysis
09-083	3/17/2009	IMP/MC Test #1 - Cyclone nozzle	ESP inlet (A/H inlet)	None
09-084	3/17/2009	IMP/MC Test #1 - Cyclone #1	ESP inlet (A/H inlet)	Morphology
09-085	3/17/2009	IMP/MC Test #1 - Cyclone #3	ESP inlet (A/H inlet)	Morphology
09-086	3/17/2009	IMP/MC Test #1 - Cyclone #4	ESP inlet (A/H inlet)	Morphology
09-087	3/17/2009	IMP/MC Test #1 - Impactor Stage 1	ESP inlet (A/H inlet)	Morphology
09-088	3/17/2009	IMP/MC Test #1 - Impactor Stage 2	ESP inlet (A/H inlet)	Morphology
09-089	3/17/2009	IMP/MC Test #1 - Impactor Stage 3	ESP inlet (A/H inlet)	Morphology
09-090	3/17/2009	IMP/MC Test #1 - Impactor Stage 4	ESP inlet (A/H inlet)	Morphology
09-091	3/17/2009	IMP/MC Test #1 - Impactor Stage 5	ESP inlet (A/H inlet)	Morphology
09-092	3/17/2009	IMP/MC Test #1 - Impactor Stage 6	ESP inlet (A/H inlet)	Morphology
09-093	3/17/2009	IMP/MC Test #1 - Impactor Stage 7	ESP inlet (A/H inlet)	Morphology
09-094	3/17/2009	IMP/MC Test #1 - Impactor outlet (backup filter)	ESP inlet (A/H inlet)	Morphology
09-097	3/18/2009	Dekati Run #1 - Stage 1	Scrubber outlet	Morphology
09-098	3/18/2009	Dekati Run #1 - Stage 2	Scrubber outlet	Morphology
09-099	3/18/2009	Dekati Run #1 - Stage 3	Scrubber outlet	Morphology
09-100	3/18/2009	Dekati Run #1 - Stage 4	Scrubber outlet	Morphology
09-101	3/18/2009	Dekati Run #1 - Stage 5	Scrubber outlet	Morphology
09-102	3/18/2009	Dekati Run #1 - Stage 6	Scrubber outlet	Morphology
09-103	3/18/2009	Dekati Run #1 - Stage 7	Scrubber outlet	Morphology
09-104	3/18/2009	Dekati Run #1 - Stage 8	Scrubber outlet	Morphology
09-105	3/18/2009	Dekati Run #1 - Stage 9	Scrubber outlet	Morphology
09-106	3/18/2009	Dekati Run #1 - Stage 10	Scrubber outlet	Morphology
09-107	3/18/2009	Dekati Run #1 - Stage 11	Scrubber outlet	Morphology
09-108	3/18/2009	Dekati Run #1 - Stage 12	Scrubber outlet	Morphology
09-109	3/18/2009	Dekati Run #1 - Stage 13	Scrubber outlet	Morphology
09-110	3/18/2009	Dekati "SEM" - Stage 1	Scrubber outlet	None
09-111	3/18/2009	Dekati "SEM" - Stage 2	Scrubber outlet	None
09-112	3/18/2009	Dekati "SEM" - Stage 3	Scrubber outlet	None
09-113	3/18/2009	Dekati "SEM" - Stage 4	Scrubber outlet	None
09-114	3/18/2009	Dekati "SEM" - Stage 5	Scrubber outlet	None
09-115	3/18/2009	Dekati "SEM" - Stage 6	Scrubber outlet	None
09-116	3/18/2009	Dekati "SEM" - Stage 7	Scrubber outlet	None
09-117	3/18/2009	Dekati "SEM" - Stage 8	Scrubber outlet	None

Table 6. List of samples and analyses performed.

Sample #	Date	Sample	Sample Location	Analysis
09-118	3/18/2009	Dekati "SEM" - Stage 9	Scrubber outlet	None
09-119	3/18/2009	Dekati "SEM" - Stage 10	Scrubber outlet	None
09-120	3/18/2009	Dekati "SEM" - Stage 11	Scrubber outlet	None
09-121	3/18/2009	Dekati "SEM" - Stage 12	Scrubber outlet	None
09-122	3/18/2009	Dekati "SEM" - Stage 13	Scrubber outlet	None
09-123	3/19/2009	Dekati Run #2 - Stage 1	Scrubber outlet	Morphology
09-124	3/19/2009	Dekati Run #2 - Stage 2	Scrubber outlet	Morphology
09-125	3/19/2009	Dekati Run #2 - Stage 3	Scrubber outlet	Morphology
09-126	3/19/2009	Dekati Run #2 - Stage 4	Scrubber outlet	Morphology
09-127	3/19/2009	Dekati Run #2 - Stage 5	Scrubber outlet	Morphology
09-128	3/19/2009	Dekati Run #2 - Stage 6	Scrubber outlet	Morphology
09-129	3/19/2009	Dekati Run #2 - Stage 7	Scrubber outlet	Morphology
09-130	3/19/2009	Dekati Run #2 - Stage 8	Scrubber outlet	Morphology
09-131	3/19/2009	Dekati Run #2 - Stage 9	Scrubber outlet	Morphology
09-132	3/19/2009	Dekati Run #2 - Stage 10	Scrubber outlet	Morphology
09-133	3/19/2009	Dekati Run #2 - Stage 11	Scrubber outlet	Morphology
09-134	3/19/2009	Dekati Run #2 - Stage 12	Scrubber outlet	Morphology
09-135	3/19/2009	Dekati Run #2 - Stage 13	Scrubber outlet	Morphology
09-136	3/18/2009	IMP Test #4 - Inlet nozzle	ESP outlet/scrubber inlet	Morphology
09-137	3/18/2009	IMP Test #4 - Impactor stage 1	ESP outlet/scrubber inlet	Morphology
09-138	3/18/2009	IMP Test #4 - Impactor stage 2	ESP outlet/scrubber inlet	Morphology
09-139	3/18/2009	IMP Test #4 - Impactor stage 3	ESP outlet/scrubber inlet	Morphology
09-140	3/18/2009	IMP Test #4 - Impactor stage 4	ESP outlet/scrubber inlet	Morphology
09-141	3/18/2009	IMP Test #4 - Impactor stage 5	ESP outlet/scrubber inlet	Morphology
09-142	3/18/2009	IMP Test #4 - Impactor stage 6	ESP outlet/scrubber inlet	Morphology
09-143	3/18/2009	IMP Test #4 - Impactor stage 7	ESP outlet/scrubber inlet	Morphology
09-144	3/18/2009	IMP Test #4 - Impactor outlet (backup filter)	ESP outlet/scrubber inlet	Morphology
09-145	3/19/2009	IMP/MC Test #5 - Impactor stage 1	ESP inlet (A/H inlet)	Morphology
09-146	3/19/2009	IMP/MC Test #5 - Impactor stage 2	ESP inlet (A/H inlet)	Morphology
09-147	3/19/2009	IMP/MC Test #5 - Impactor stage 3	ESP inlet (A/H inlet)	Morphology
09-148	3/19/2009	IMP/MC Test #5 - Impactor stage 4	ESP inlet (A/H inlet)	Morphology
09-149	3/19/2009	IMP/MC Test #5 - Impactor stage 5	ESP inlet (A/H inlet)	Morphology
09-150	3/19/2009	IMP/MC Test #5 - Impactor stage 6	ESP inlet (A/H inlet)	Morphology
09-151	3/19/2009	IMP/MC Test #5 - Impactor stage 7	ESP inlet (A/H inlet)	Morphology
09-152	3/19/2009	IMP Test #5 - Impactor outlet (backup filter)	ESP inlet (A/H inlet)	Morphology
09-153	3/19/2009	IMP Test #6 - Inlet nozzle	ESP outlet/scrubber inlet	Morphology
09-154	3/19/2009	IMP Test #6 - Impactor stage 1	ESP outlet/scrubber inlet	Morphology
09-155	3/19/2009	IMP Test #6 - Impactor stage 2	ESP outlet/scrubber inlet	Morphology
09-156	3/19/2009	IMP Test #6 - Impactor stage 3	ESP outlet/scrubber inlet	Morphology
09-157	3/19/2009	IMP Test #6 - Impactor stage 4	ESP outlet/scrubber inlet	Morphology
09-158	3/19/2009	IMP Test #6 - Impactor stage 5	ESP outlet/scrubber inlet	Morphology
09-159	3/19/2009	IMP Test #6 - Impactor stage 6	ESP outlet/scrubber inlet	Morphology
09-160	3/19/2009	IMP Test #6 - Impactor stage 7	ESP outlet/scrubber inlet	Morphology
09-161	3/19/2009	IMP Test #6 - Impactor outlet (backup filter)	ESP outlet/scrubber inlet	Morphology
09-162	3/19/2009	IMP Test #5 - Film from stage 1	ESP outlet/scrubber inlet	Morphology
09-163	3/18/2009	IMP Test #4 - Film from stage 2 (bottom of jets)	ESP outlet/scrubber inlet	None

Table 6. List of samples and analyses performed.

Sample #	Date	Sample	Sample Location	Analysis
09-164	3/18/2009	IMP Test #4 - Film from stage 3 (bottom of jets)	ESP outlet/scrubber inlet	None
09-165	3/18/2009	IMP Test #4 - Film from stage 4 (bottom of jets)	ESP outlet/scrubber inlet	None
09-166	3/18/2009	IMP Test #4 - Film from stage 5 (bottom of jets)	ESP outlet/scrubber inlet	None
09-167	3/19/2009	IMP Test #6 - Film from stage 4 (back of jets)	ESP outlet/scrubber inlet	Morphology
09-168	3/19/2009	IMP/MC Test #5 - Cyclone stage 6	ESP inlet (A/H inlet)	Morphology
09-169	3/19/2009	IMP/MC Test #5 - Cyclone stage 7	ESP inlet (A/H inlet)	Morphology
09-170	3/19/2009	IMP/MC Test #5 - Cyclone #1	ESP inlet (A/H inlet)	Morphology
09-171	3/19/2009	IMP/MC Test #5 - Cyclone #3	ESP inlet (A/H inlet)	Morphology
09-172	3/19/2009	IMP/MC Test #5 - Cyclone #4	ESP inlet (A/H inlet)	Morphology
09-173	3/19/2009	IMP/MC Test #5 - Cyclone nozzle	ESP inlet (A/H inlet)	Morphology
09-174	3/19/2009	ESP Ash - Row 1 3B1	ESP	None
09-175	3/19/2009	ESP Ash - Row 2 3B2	ESP	None
09-176	3/19/2009	ESP Ash - Row 3 3B3	ESP	None
09-177	3/19/2009	ESP Ash - Row 4 3B4	ESP	None
09-178	3/16/2009	Coal sample – composite	Feeders	Proximate, ash composition, CCSEM
09-179	3/17/2009	Coal sample – composite	Feeders	Proximate, ash composition, CCSEM
09-180	3/18/2009	Coal sample – composite	Feeders	Proximate, ash composition, CCSEM
09-181	3/19/2009	Coal sample – composite	Feeders	Proximate, ash composition, CCSEM
09-184	3/16/2009	IMP Test #2 - Impactor stage 1	ESP outlet/scrubber inlet	Morphology
09-185	3/16/2009	IMP Test #2 - Impactor stage 2	ESP outlet/scrubber inlet	Morphology
09-186	3/16/2009	IMP Test #2 - Impactor stage 3	ESP outlet/scrubber inlet	Morphology
09-187	3/16/2009	IMP Test #2 - Impactor stage 4	ESP outlet/scrubber inlet	Morphology
09-188	3/16/2009	IMP Test #2 - Impactor stage 5	ESP outlet/scrubber inlet	Morphology
09-189	3/16/2009	IMP Test #2 - Impactor stage 6	ESP outlet/scrubber inlet	Morphology
09-190	3/16/2009	IMP Test #2 - Impactor stage 7	ESP outlet/scrubber inlet	Morphology
09-191	3/16/2009	IMP Test #2 - Impactor outlet (backup filter)	ESP outlet/scrubber inlet	Morphology
09-192	3/16/2009	IMP Test #2 - Impactor nozzle	ESP outlet/scrubber inlet	None
09-193	3/17/2009	IMP Test #3 - Impactor stage 1	ESP outlet/scrubber inlet	None
09-194	3/17/2009	IMP Test #3 - Impactor stage 2	ESP outlet/scrubber inlet	None
09-195	3/17/2009	IMP Test #3 - Impactor stage 3	ESP outlet/scrubber inlet	None
09-196	3/17/2009	IMP Test #3 - Impactor stage 4	ESP outlet/scrubber inlet	None
09-197	3/17/2009	IMP Test #3 - Impactor stage 5	ESP outlet/scrubber inlet	None
09-198	3/17/2009	IMP Test #3 - Impactor stage 6	ESP outlet/scrubber inlet	None
09-199	3/17/2009	IMP Test #3 - Impactor stage 7	ESP outlet/scrubber inlet	None
09-200	3/17/2009	IMP Test #3 - Impactor outlet (backup filter)	ESP outlet/scrubber inlet	None
09-201	3/17/2009	IMP Test #3 - Impactor nozzle	ESP outlet/scrubber inlet	None

RESULTS AND DISCUSSION

Coal Analysis and Plant Operating Conditions during Testing

The coal samples for each day were composited to form one larger sample; the four resulting composite coal samples were subjected to proximate and ash composition analyses. The results of the analyses are shown in **Table 7**. The coal was relatively consistent over the time period sampled. The as-received ash content ranged from 7.73 to 7.89%. Sodium content ranged from 7.22 to 7.57% and the base-to-acid ratio decreased the last two days of testing as a result of a decrease in CaO content and an increase in SiO_2 and Al_2O_3 levels.

Table 7. Proximate and ash composition analyses for four composite coal samples taken from MRY coal feeders on March 16 through 19, 2009.

	MTI 09-178 3/16/09 Composite		MTI 09-179 3/17/09 Composite		MTI 09-208 3/18/09 Composite		MTI 09-209 3/19/09 Composite	
Proximate (wt% in coal)	*As-rec'd*	*Dry*	*As-rec'd*	*Dry*	*As-rec'd*	*Dry*	*As-rec'd*	*Dry*
Total moisture	37.58		37.24		37.23		36.10	
Ash	7.89	12.64	7.85	12.51	7.84	12.49	7.73	12.10
Volatile matter	24.80	39.73	25.15	40.07	25.22	40.18	25.81	40.39
Fixed carbon	29.73	47.63	29.76	47.42	29.71	47.33	30.36	47.51
Heating value (BTU/lb)	6732	10785	6784	10810	6701	10676	6851	10721
Total sulfur	0.90	1.44	1.00	1.59	0.65	1.04	0.77	1.21
Ash Composition (wt% in ash)								
SiO2		26.92		26.08		34.46		31.06
Al2O3		8.78		8.81		11.61		10.63
TiO2		0.39		0.36		0.44		0.39
Fe2O3		11.17		12.96		7.75		8.49
CaO		15.23		14.99		14.01		15.26
MgO		4.55		4.38		4.37		4.70
K2O		1.24		1.55		1.68		1.46
Na2O		7.22		7.57		7.31		7.24
SO3		19.50		18.70		14.88		16.92
P2O5		0.45		0.40		0.33		0.47
SrO		0.45		0.43		0.41		0.44
BaO		0.72		0.55		0.61		0.63
MnO2		0.09		0.08		0.08		0.08
SiO2/Al2O3		***3.07***		***2.96***		***2.97***		***2.92***
Base/Acid		***1.09***		***1.18***		***0.76***		***0.88***

Figures 4 and **5** show the overall coal flow rate, along with the ash quantity and base-to-acid ratio determined with the Full-Stream Elemental Analyzer (FSEA) during the test period. The FSEA data was corrected for a 23-hour lag time between filling the hoppers and feeding coal to the cyclones. These data show a decrease in the base-to-acid ratio during the testing period. This was observed in the analysis of the four daily composite samples.

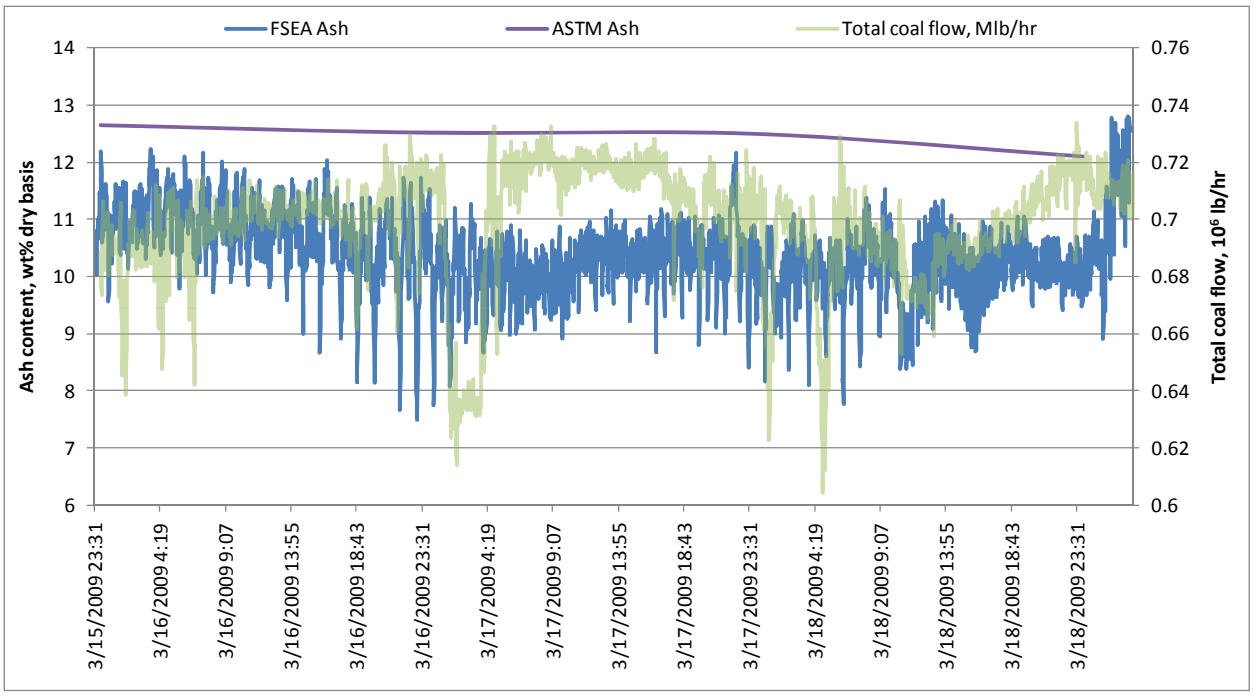


Figure 4. Coal belt flow and fuel ash quantity (determined with FSEA and by ASTM method on composite coal samples) during the testing. The FSEA data was corrected for a 23-hour lag time between filling the hoppers and estimated fuel fed to the cyclones.

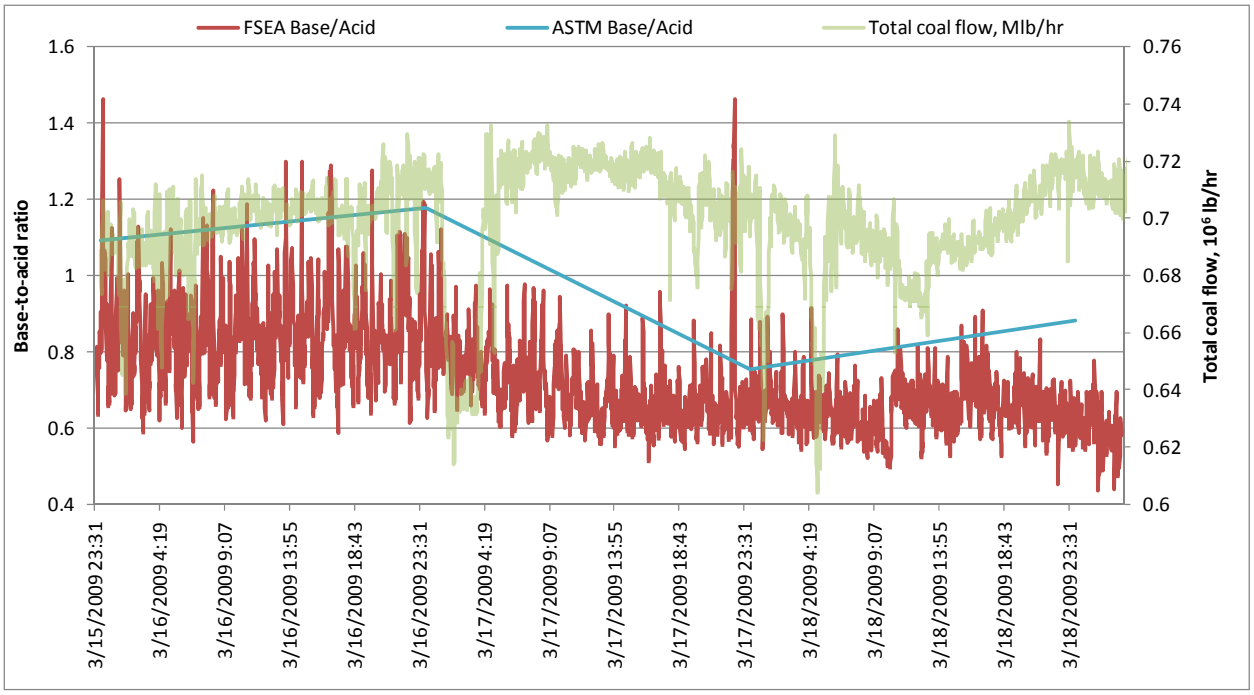


Figure 5. Coal belt flow and base-to-acid ratio (determined with FSEA and by ASTM ash composition analyses performed on composite coal samples) during the testing. The FSEA data was corrected for a 23-hour lag time between filling the hoppers and estimated fuel fed to the cyclones.

Particulate Mass and Number Distribution

Mass Distribution as Function of Location

The total mass loadings obtained with the multicyclone and impactors are illustrated in **Figure 6**. The results show a high average loading of 4.96×10^6 micrograms per dry standard cubic meter (µg/dscm) at the ESP inlet, and average scrubber inlet and outlet loadings of 1.1×10^4 µg/dscm and 1.08×10^4 µg/dscm, respectively. Significant removal of particulate occurred across the ESP, with removal efficiency of 99.76%. These results show that very little removal of particulate material has occurred across the wet scrubber system. This is consistent with past work conducted by Markowski and others (1983) (a literature review is contained in **Appendix B** of this report). The results are also summarized in **Table 8**.

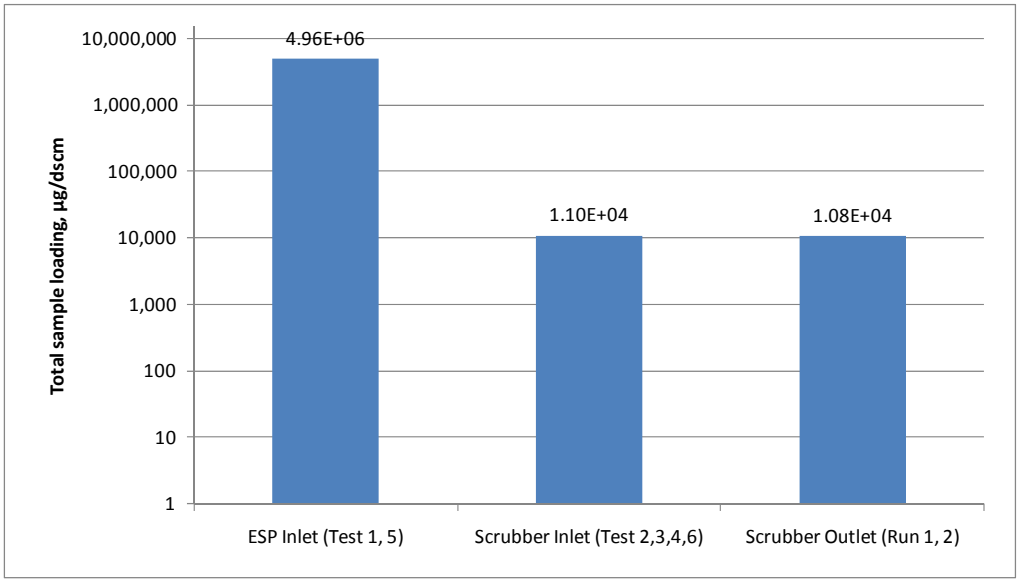


Figure 6. Total mass loadings at ESP inlet, wet scrubber inlet, and wet scrubber outlet.

Table 8. Total mass loadings for all testing conducted at ESP inlet, wet scrubber inlet, and wet scrubber outlet.

				Sampler loading		Total loading
Location	**Date**	**Test #**	**Sampler type**	**mg/dscm**	**µg/dscm**	**µg/dscm**
ESP inlet	3/17/2009	Test 1	Impactor	5.25E+02	5.25E+05	
ESP inlet	3/17/2009	Test 1	Cyclone	4.19E+03	4.19E+06	4.72E+06
Scrubber inlet	3/16/2009	Test 2	Impactor	1.25E+01	1.25E+04	1.25E+04
Scrubber inlet	3/17/2009	Test 3	Impactor	9.77E+00	9.77E+03	9.77E+03
Scrubber inlet	3/18/2009	Test 4	Impactor	1.15E+01	1.15E+04	1.15E+04
ESP inlet	3/19/2009	Test 5	Impactor	3.73E+02	3.73E+05	
ESP inlet	3/19/2009	Test 5	Cyclone	4.84E+03	4.84E+06	5.21E+06
Scrubber inlet	3/19/2009	Test 6	Impactor	1.03E+01	1.03E+04	1.03E+04
Scrubber outlet	3/18/2009	Run 1	Dekati Impactor		9109.506	9.11E+03
Scrubber outlet	3/19/2009	Run 2	Dekati Impactor		12560.87	1.26E+04

Particulate Mass Loading as a Function of Size

Sampling at the ESP inlet was conducted using both the multicyclone and the impactor. The cyclones are designed to capture larger-size particles and the impactor collects small particles. **Figure 7** shows the mass size distributions for the cyclone and impactor. The size distribution of the particulate at the ESP inlet is multimodal. The larger particles are typically derived from mineral grains in the coal such as quartz, clays, and pyrite minerals. The intermediate-sized particles are typically derived from small minerals and organically associated elements. Particles less than a micron in diameter and finer are condensed vapor phase species.

The sample collected on 3/17/09 show a multimodal size distribution, with a mode occurring at one to three microns, and another mode at 0.1 µm. The sample collected on 3/19/09 also has a multimodal distribution, with a shift in the finer mode from 0.1 µm to about 0.5 µm. This shift may be due to the change in fuel composition (the coal sample collected on 3/17/09 had a higher base-to-acid ratio as compared to the coal collected on 3/19/09).

The mass size distribution of the particulate collected upstream of the scrubber is illustrated in **Figure 8**. Sampling was conducted at this location on all four days of the period. The results show a bimodal distribution of particles with a mode between one to two microns and another mode between seven and eleven microns. A general trend of decreasing abundance of the modes during the testing is observed. The change in abundance is likely due to changes in coal ash composition. Coals sampled on 3/16 and 3/17 had higher base-to-acid ratios; coals on 3/18 and 3/19 had lower ratios.

The mass size distribution of the scrubber outlet particulate is illustrated in **Figure 9**. The size distribution shows a main mode at about 0.8 µm and possibly a minor larger mode of 2 µm. The particle size distribution is shifted to finer particles downstream of the scrubber and the smaller particle size mode appears to dominate the size distribution. The samples were collected on 3/18 and 3/19, when the coals fired had lower base-to-acid ratios.

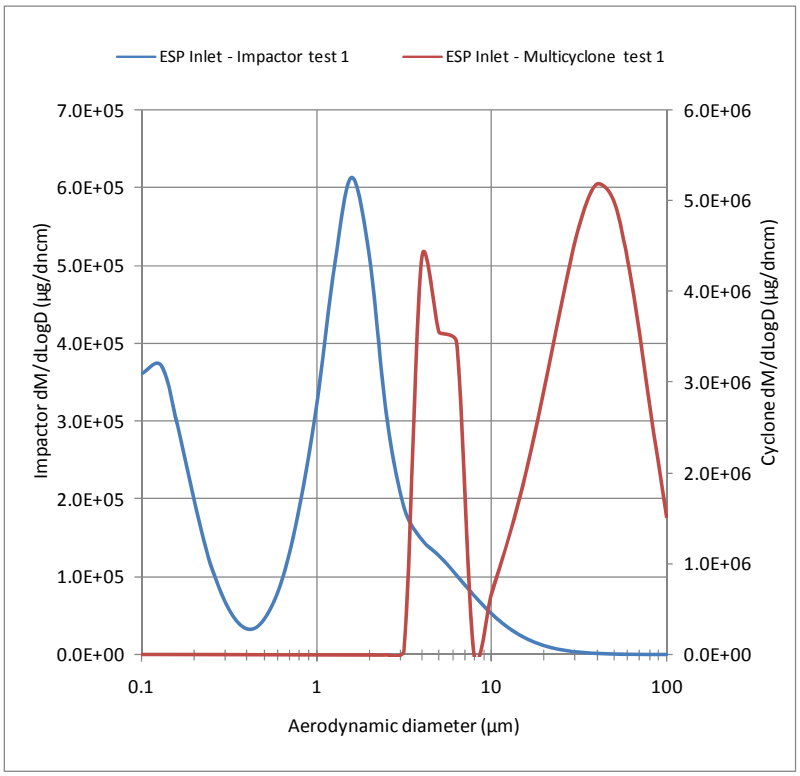


Figure 7a. Multicyclone and impactor data collected at ESP inlet on 3/17/09.

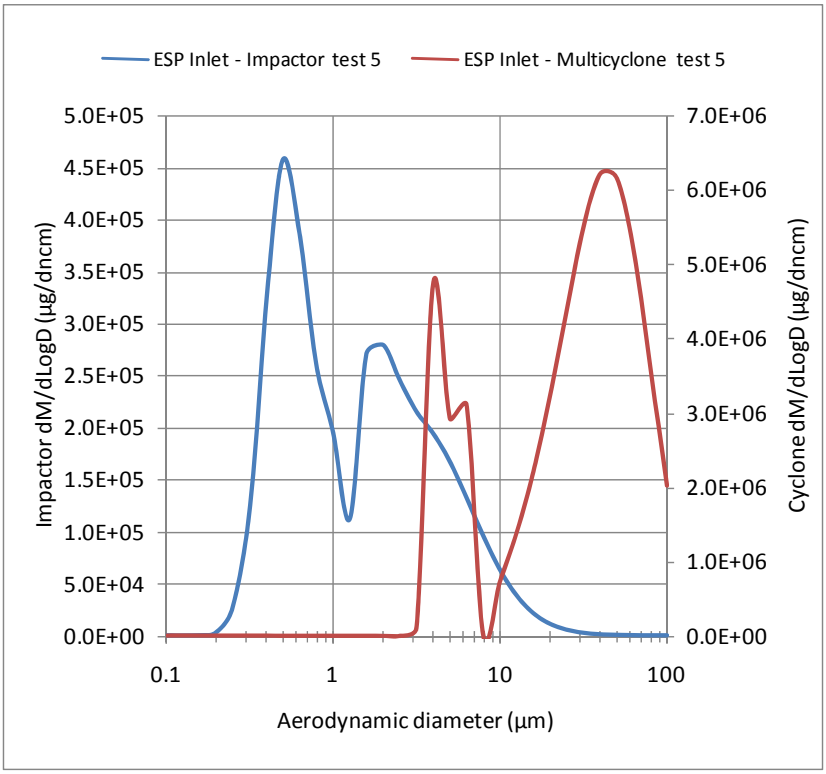


Figure 7b. Multicyclone and impactor data collected at ESP inlet on 3/19/09.

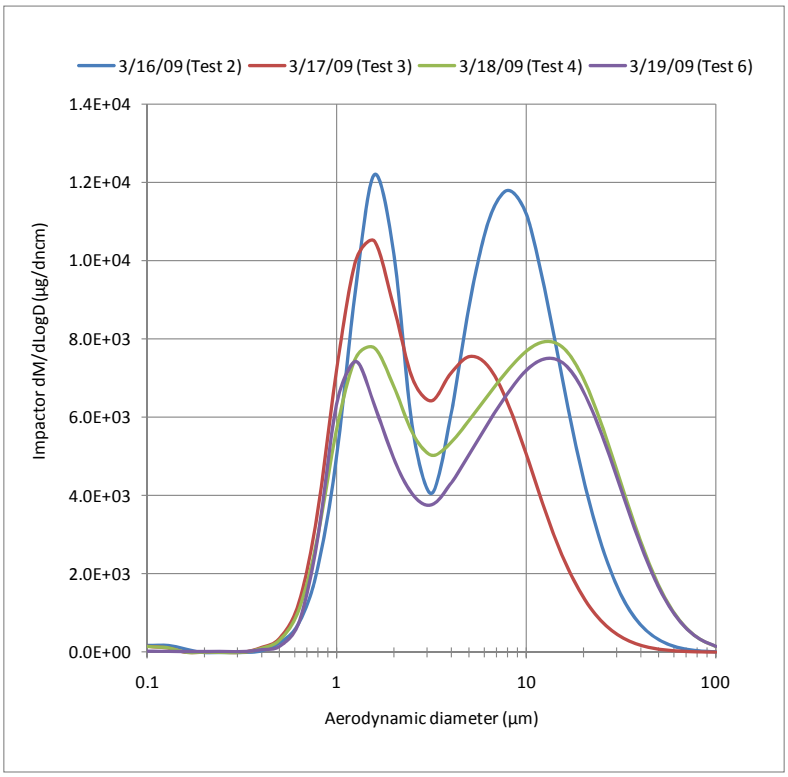


Figure 8. Mass versus size distribution of ash collected downstream of the ESP at the scrubber inlet.

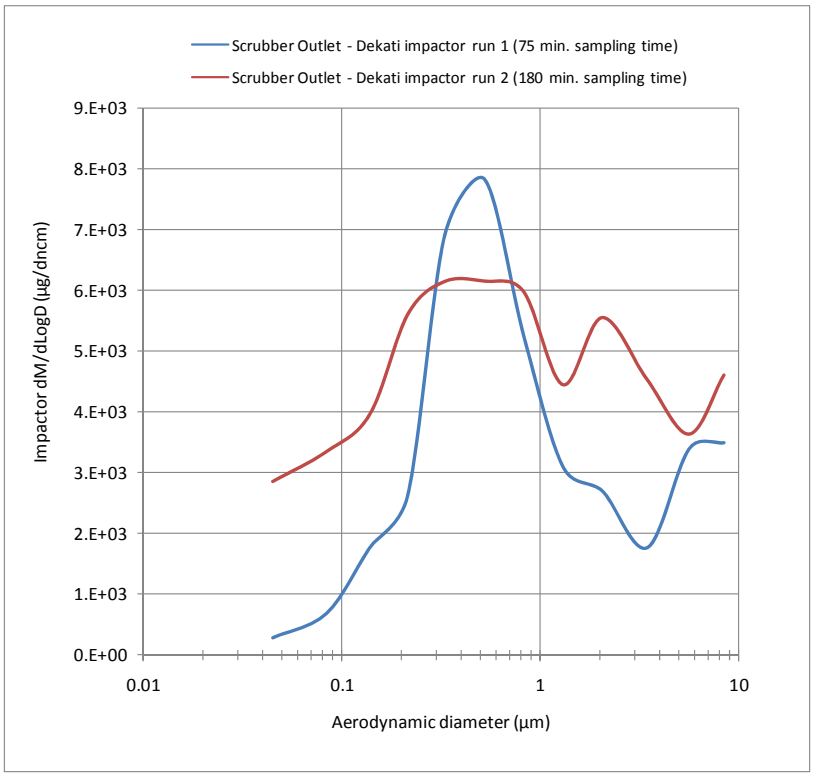


Figure 9. Mass distribution of particulate collected downstream of scrubber.

Particle Number Size Distribution

The number distributions for the particles are shown in **Figures 10** through **12** for the ESP inlet, scrubber inlet, and scrubber outlet. This information is shown as the number of particles per dry normal cubic centimeters (*not* cubic meters ash summarized above). This is the convention used by researchers.

The number of particle increases significantly with decreasing particles size. **Figure 10** shows the number of particles for the scrubber inlet. The ESP inlet sample had the highest number of particles in the smallest size fraction. The number of particles in the smallest size fraction at the scrubber inlet and outlet are similar – the slight increase in number at the scrubber outlet is likely to differences in sampling methods.

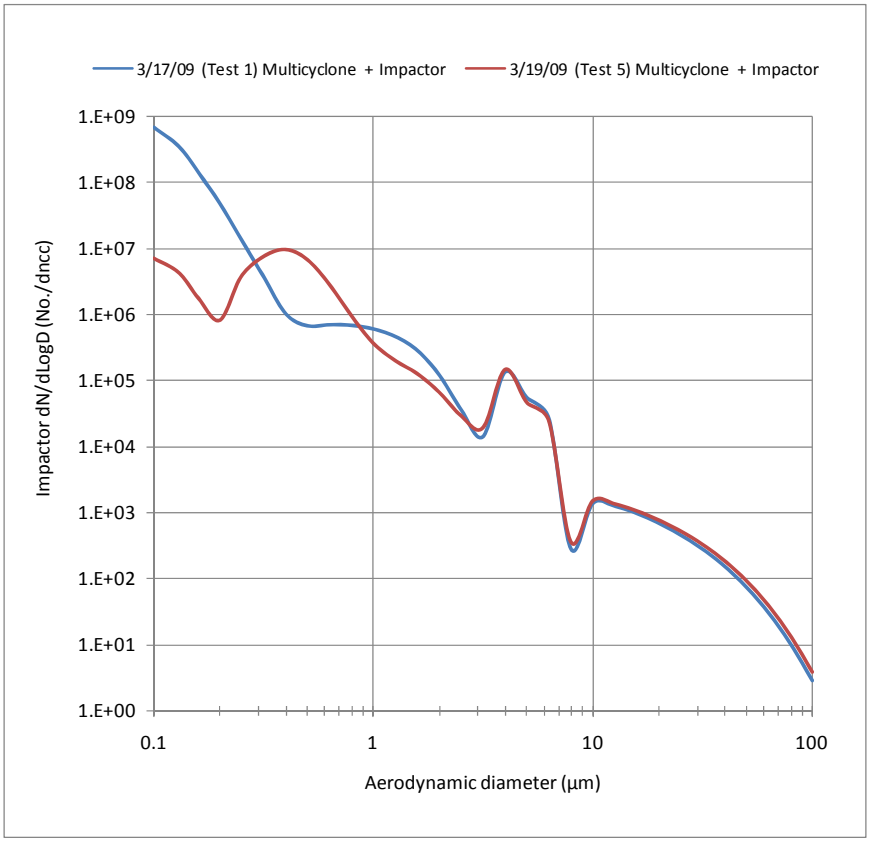


Figure 10. Number of particles as a function of size at the ESP Inlet.

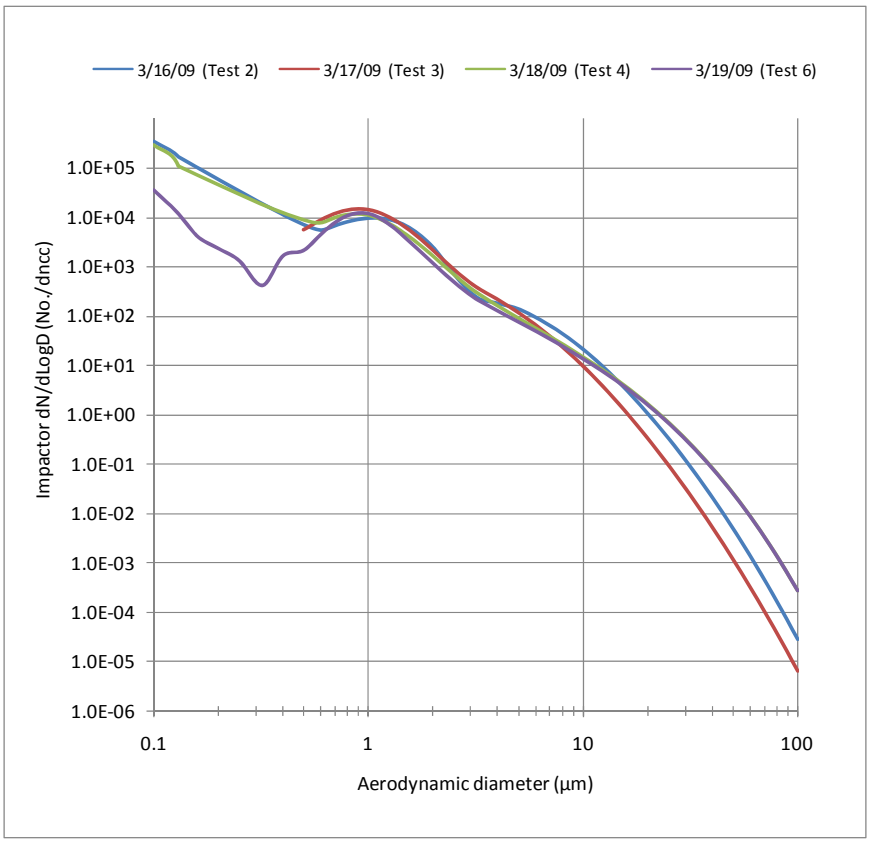


Figure 11. Number of particles as a function of size at the scrubber inlet.

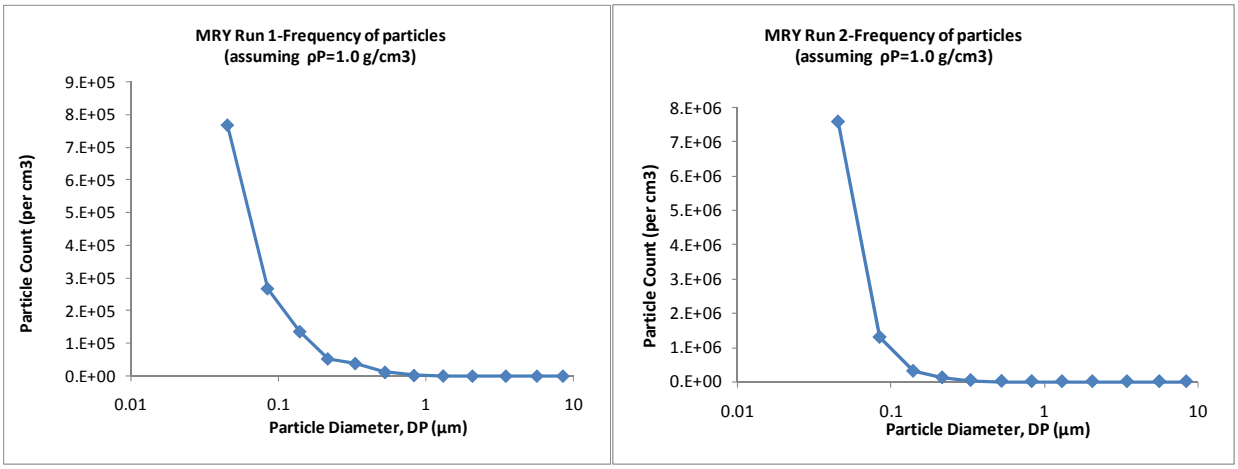


Figure 12. Number of particles as a function of size at the scrubber outlet.

Scanning Mobility Particle Scanning (SMPS)

Number-based concentration data obtained by the SMPS system at the scrubber outlet is shown in **Figures 13** and **14**. The data shown are for the on one good data set obtained during the sampling trip. A summary of the conditions at the sampling site that limited the ability of the SMPS to gain reliable data is listed in the Appendix.

The SMPS reports size data on a nanometer (nm) scale, not a micrometer (µm) scale. There are 1,000 nm in one micron. The data shown was obtained from a 10-sample test run, each 60 seconds apart, and includes two scans per sample: 60 seconds for the up scan and 30 seconds for the down scan. The scan window of the instrument covers a particle range of 16.5–605 nm (0.0165–0.605 µm).

Plots of the concentration versus particle diameter are given in **Figure 13** for number basis and in **Figure 14** for the mass basis. The number of particles observed using the SMPS is larger than that observed for the impactors but it is generally consistent the impactor data.

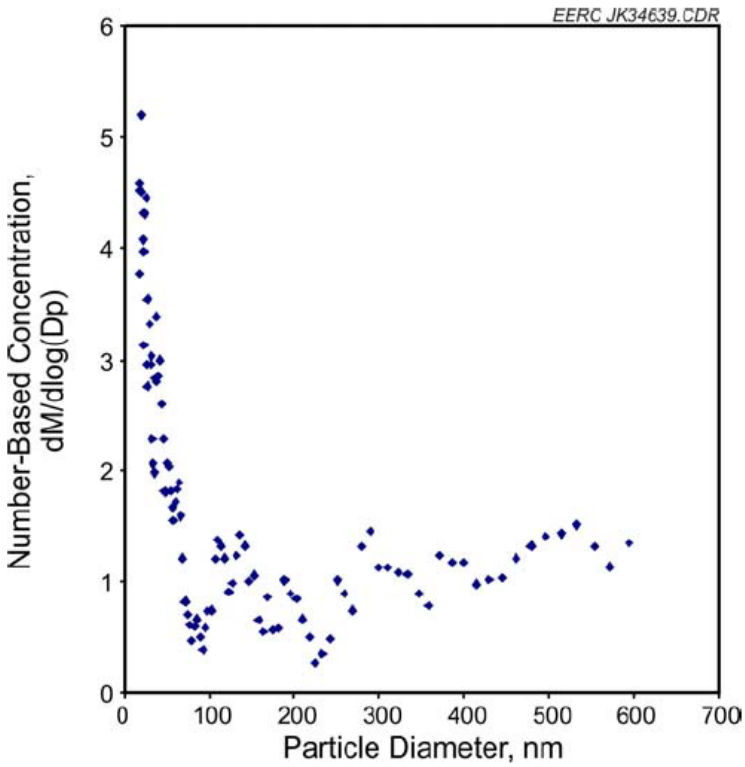


Figure 13. Plot of number-based particle concentration as a function of particle diameter (nanometers).

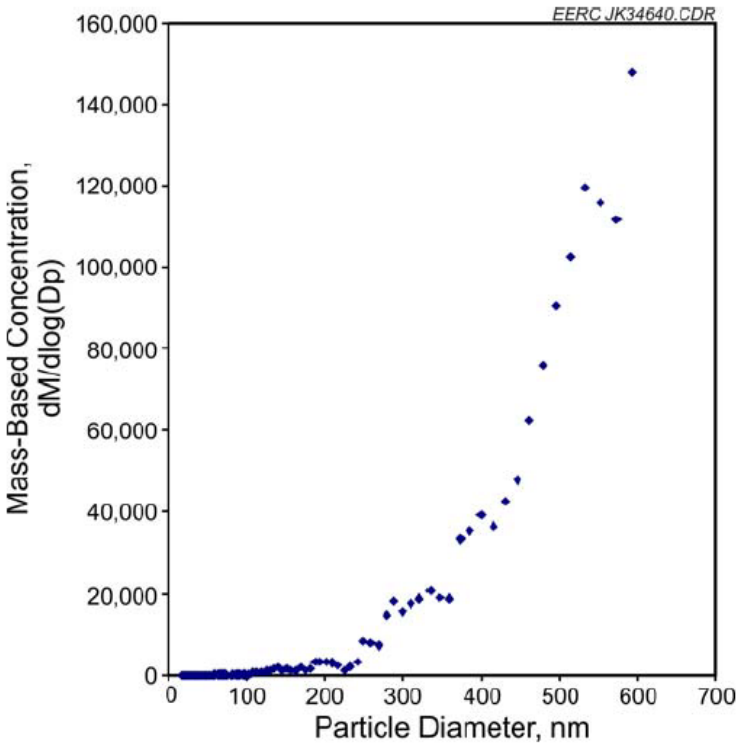


Figure 14. Plot of mass-based particle concentration as a function of particle diameter (nanometers).

Bulk Composition of Ash Materials

The composition of the size fractions of ash materials collected using the multicyclone are summarized for the element of interest specifically the Na, K, Ca, and S. These elements produce very small particles upon combustion. Data is available in the appendix that includes the major elements determined. The trends for the ESP inlet are shown in **Figure 15** for sodium, potassium, calcium and sulfur, and in **Figure 16** for silicon, aluminum, magnesium and iron. The results show concentrating of the elements in the particles that are less than 10 μm in diameter.

Figure 17 shows the trend for the ESP inlet cyclone samples (cyclones 1, 3 and 4) for sodium, potassium, calcium and sulfur and **Figure 18** shows the trends for silicon, aluminum, magnesium and iron for the ESP inlet cyclone samples.

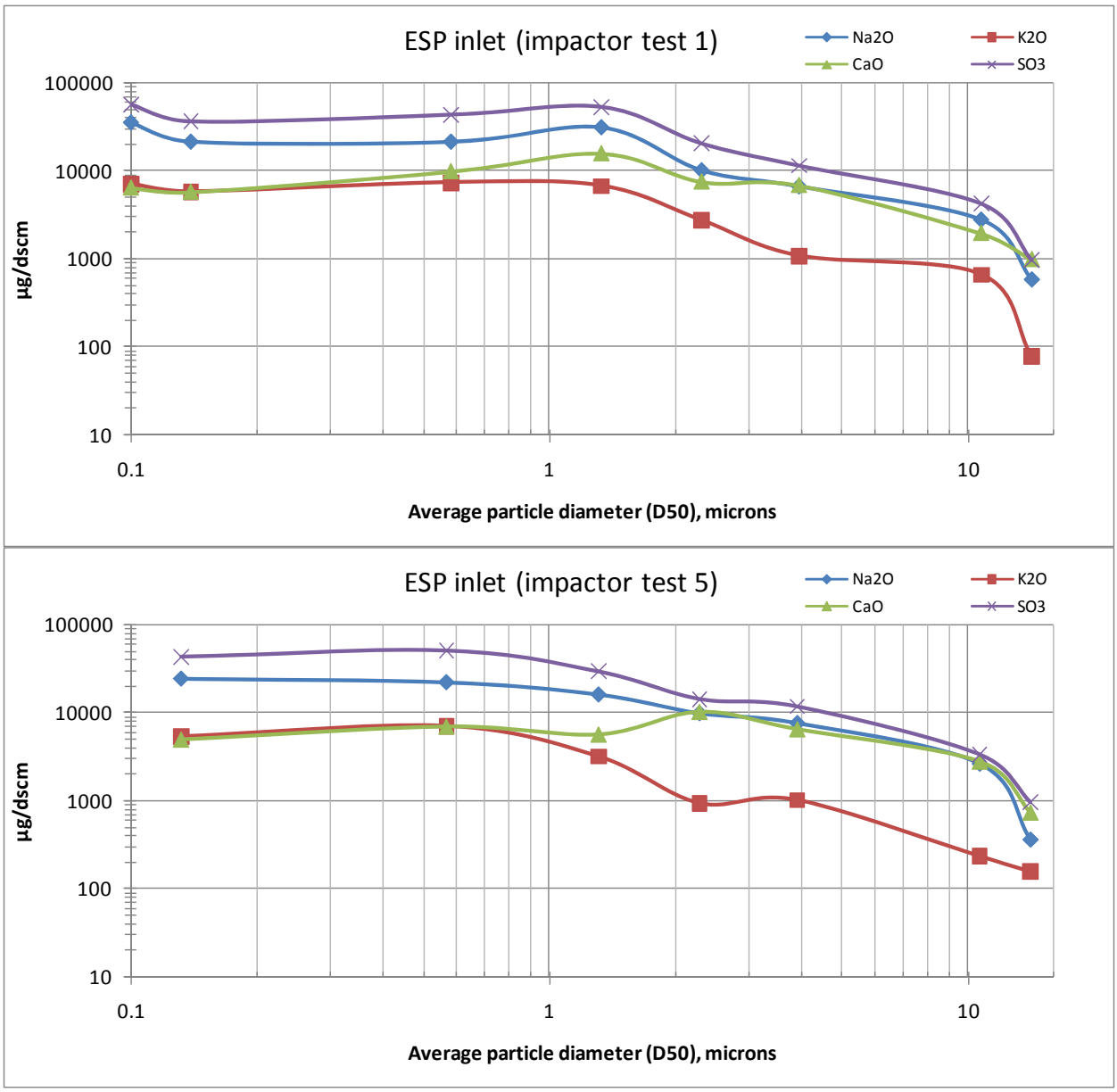


Figure 15. Sodium, potassium, calcium and sulfur concentrations as a function of average particle diameter for ESP inlet (impactor) samples.

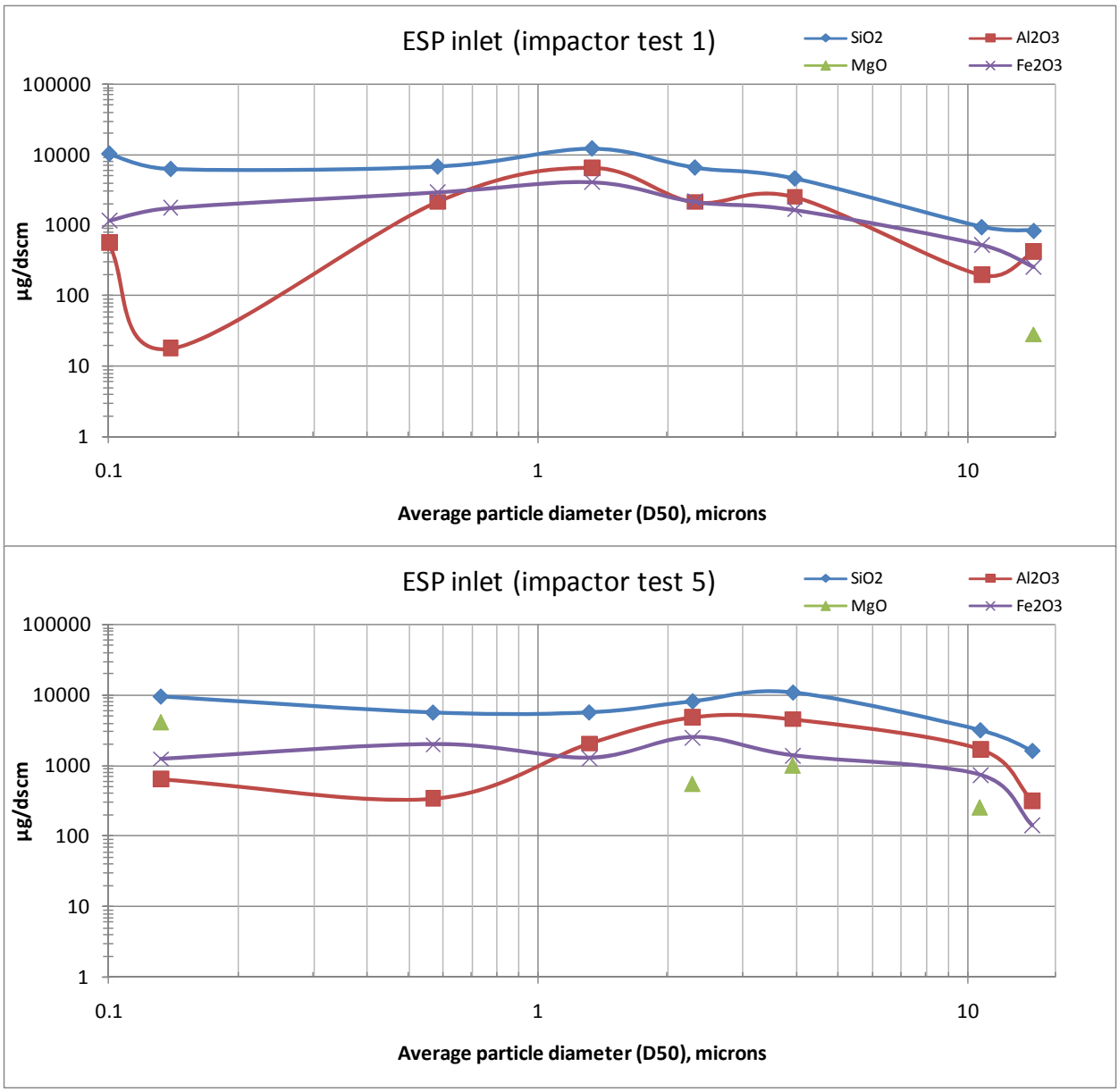


Figure 16. Silicon, aluminum, magnesium and iron concentrations as a function of average particle diameter for ESP inlet (impactor) samples.

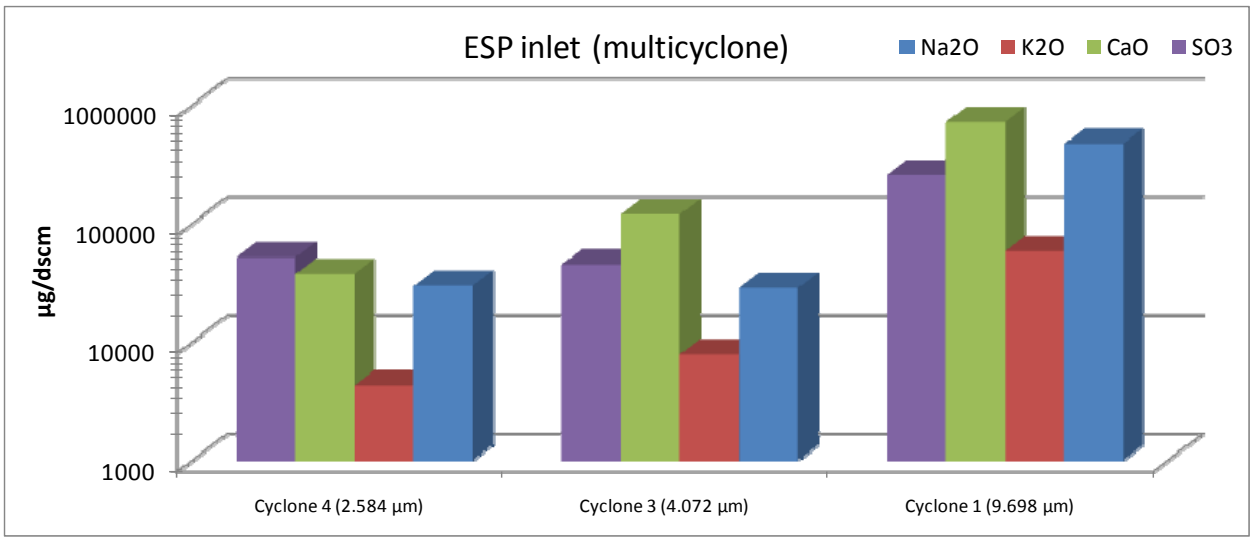


Figure 17. Sodium, potassium, calcium and sulfur concentrations for ESP inlet cyclone samples.

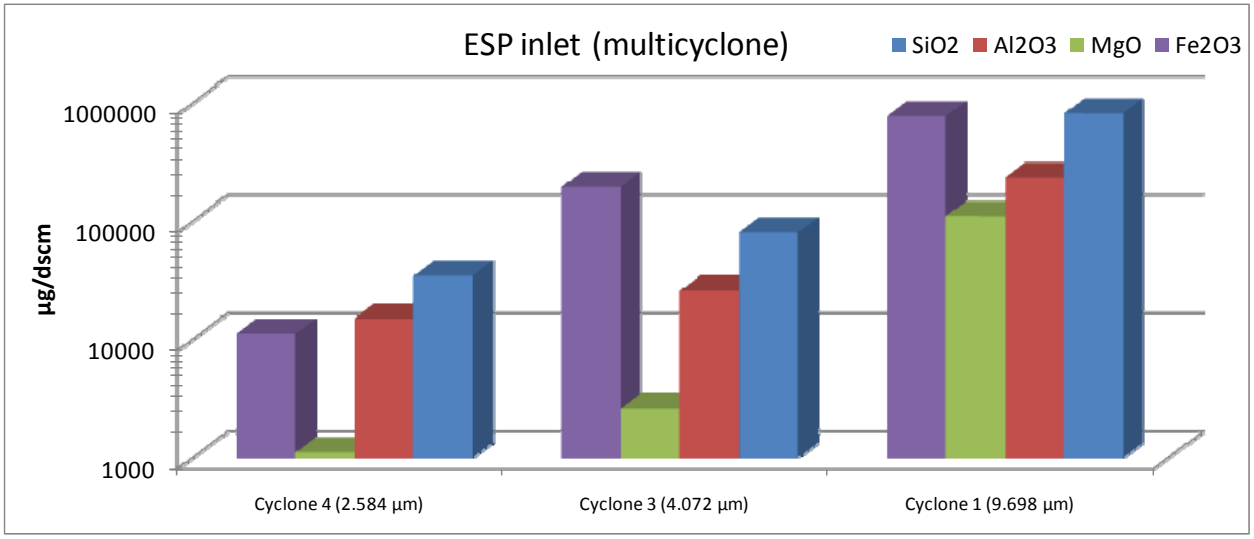


Figure 18. Silicon, aluminum, magnesium and iron concentrations for ESP inlet cyclone samples.

Analysis using digestion and inductively coupled plasma–mass spectrometry was performed to determine the concentrations of selected major elements (Ca, Fe, Mg, P, K, and Na) in the ash collected in the multicyclone stages. Table 9 lists the composition of selected elements based on the total sample collected in the multicyclone. Table 10 displays the fraction of each element, based on the total percent found in Table 9, by each cyclone stage. The largest concentrations of the selected elements were found in the first cyclone stage. The nozzle sample is material collected within the nozzle before the first multicyclone stage. This material is not size-fractionated.

The concentrations of the cyclone ash analyzed with ICP-MS cannot be compared well with the ash analyzed using SEM, as the ICP-MS samples were not analyzed for all major elements (including silicon, aluminum and sulfur).

Table 9. Percentage of each element in the total multicyclone sample (EERC).

Element	03/17/2009	03/19/2009
Calcium	13.36	12.15
Iron	6.85	6.54
Magnesium	3.27	3.14
Phosphorous	LBD*	LBD
Potassium	0.93	1.00
Sodium	6.63	6.26

* Level below detection (<400 ppm).

Table 10. Fractional percentage of each element by stage (EERC).

	03/17/2009				03/19/2009			
Element	Nozzle	Stage 1	Stage 3	Stage 4	Nozzle	Stage 1	Stage 3	Stage 4
Calcium	3.96	81.23	11.63	3.18	4.99	81.98	9.77	3.26
Iron	4.21	81.77	10.16	3.86	5.25	81.06	8.90	4.79
Magnesium	4.10	81.45	11.71	2.75	5.25	81.81	9.91	3.03
Phosphorous	LBD	LBD	LBD	LBD	LBD	LBD	LBD	LBD
Potassium	3.91	77.32	12.77	5.99	5.08	80.67	10.18	4.07
Sodium	4.21	77.80	12.82	5.17	5.67	80.59	9.88	3.85

The distribution of sodium, potassium, calcium and sulfur is illustrated in **Figure 19** and the distribution of silicon, aluminum, magnesium and iron is shown in **Figure 20**. The results show higher levels of sodium, potassium and sulfur at the one-micron level. The ESP was effective in removing larger-sized particles as well as some of the 0.1-µm particles. However, in the intermediate one-micron particle range the ESP is not as effective in removing the particles. This is a characteristic of all ESPs.

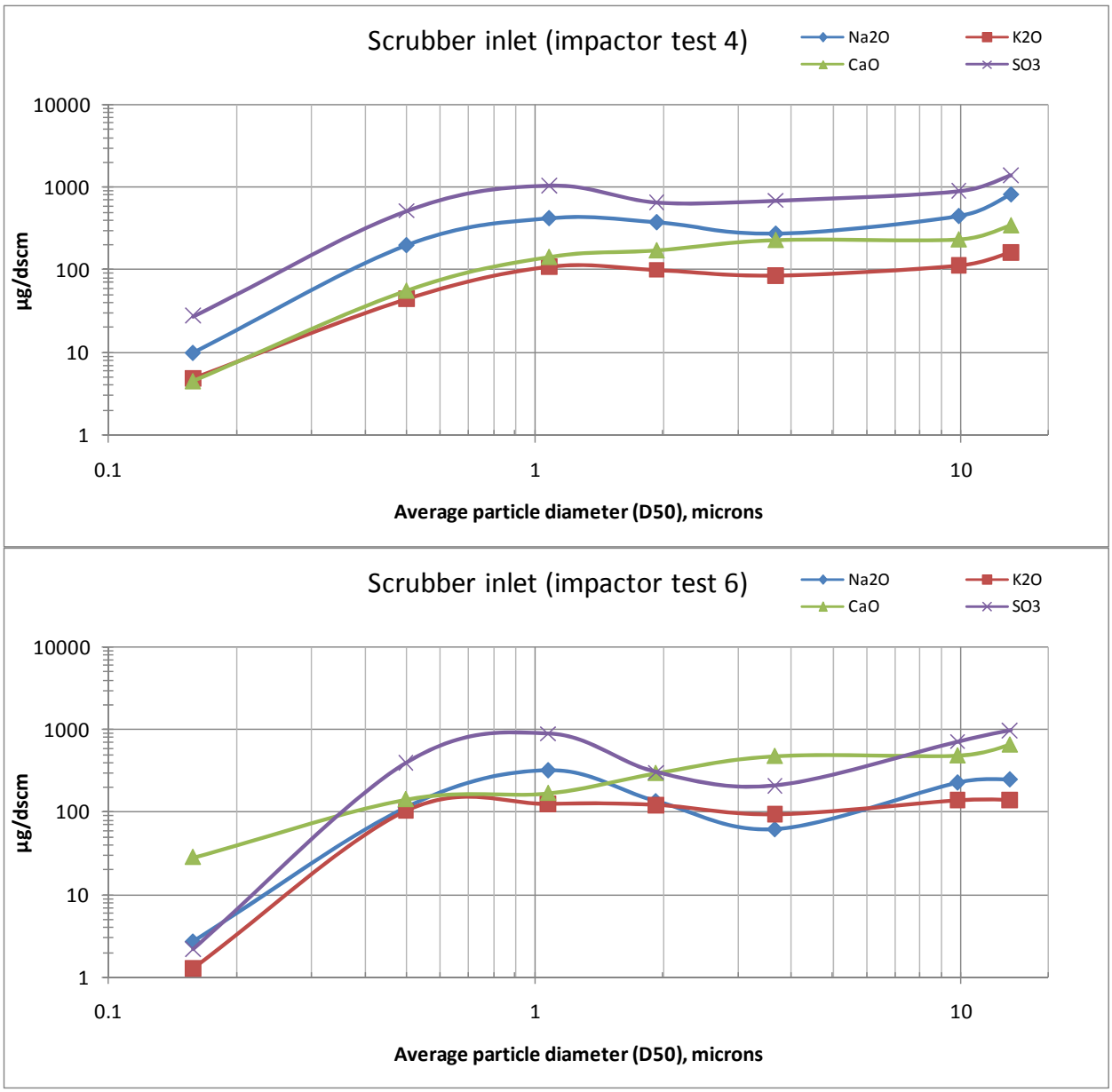


Figure 19. Sodium, potassium, calcium and sulfur concentrations as a function of average particle diameter in scrubber inlet samples.

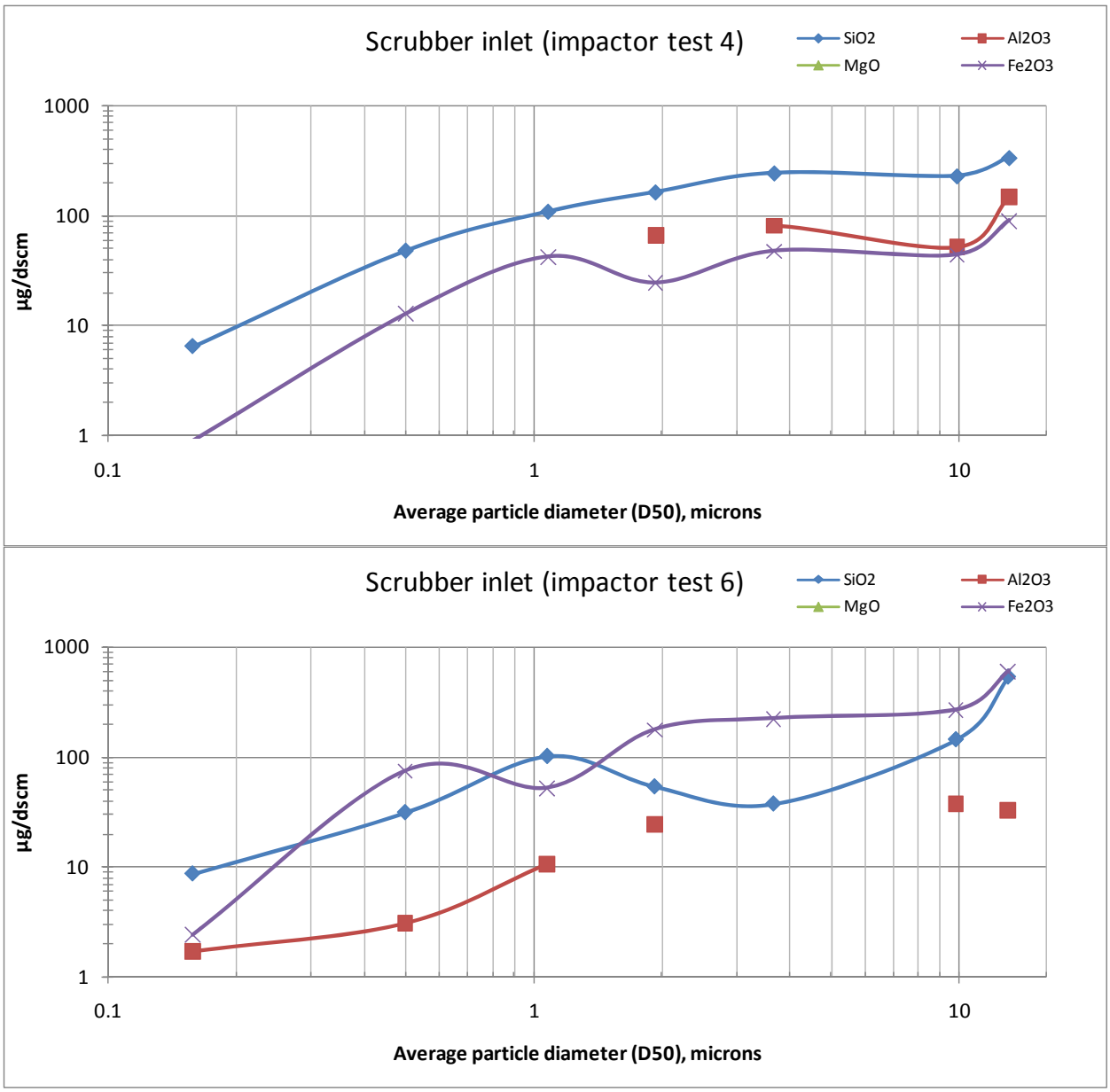


Figure 20. Silicon, aluminum, magnesium and iron concentrations as a function of average particle diameter in scrubber inlet samples.

The composition size distribution determined for sodium, potassium, calcium and sulfur downstream of the scrubber is illustrated in Figure 21. The results show a significant level of sodium and sulfur in the less than 1 µm size fraction. The DLPI sampling system provides very accurate sizing data in the submicron size range. The results show a maximum for sodium and sulfur at about 0.3 µm.

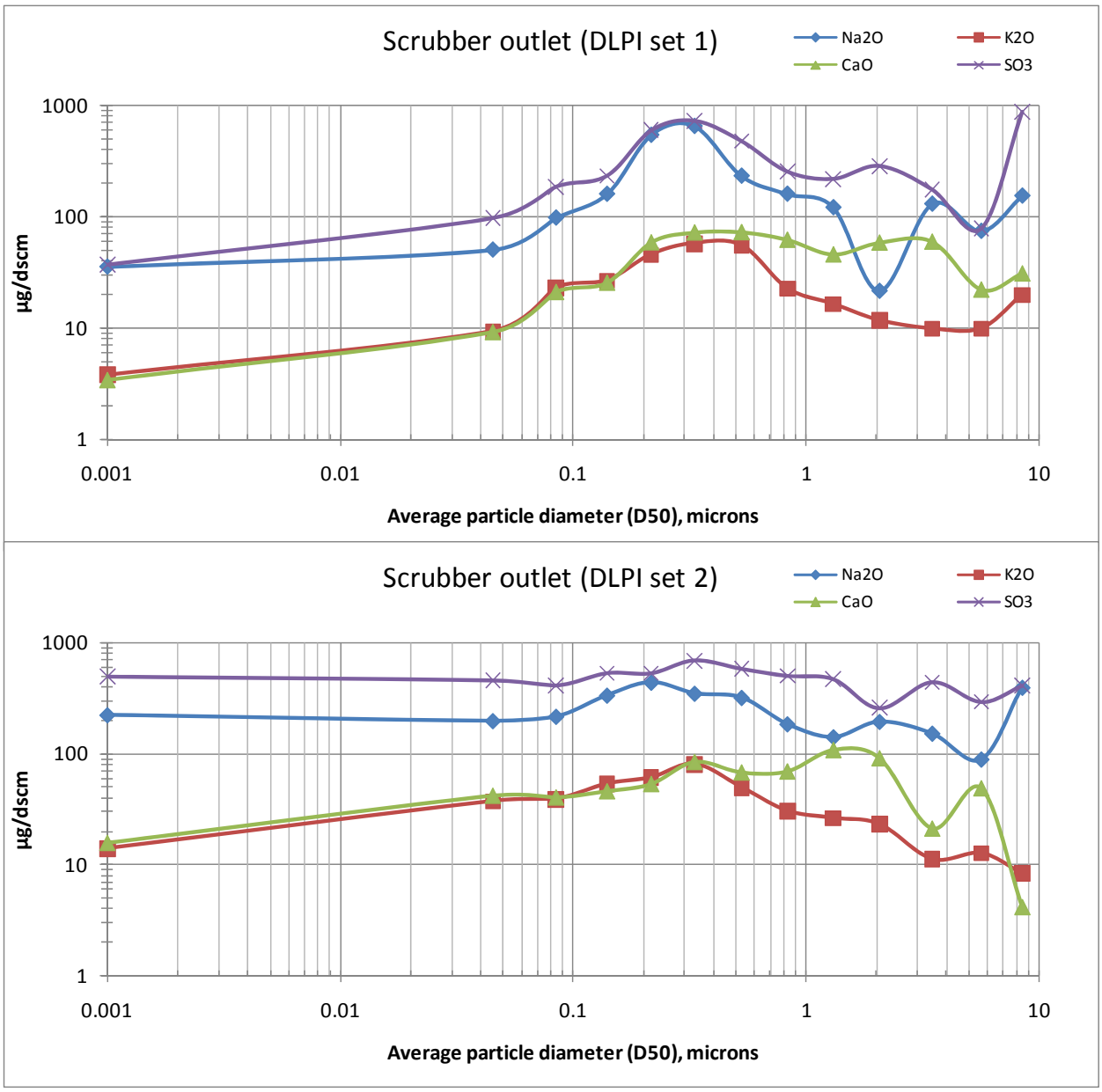


Figure 21. Sodium, potassium, calcium and sulfur concentrations as a function of average particle diameter in scrubber outlet samples.

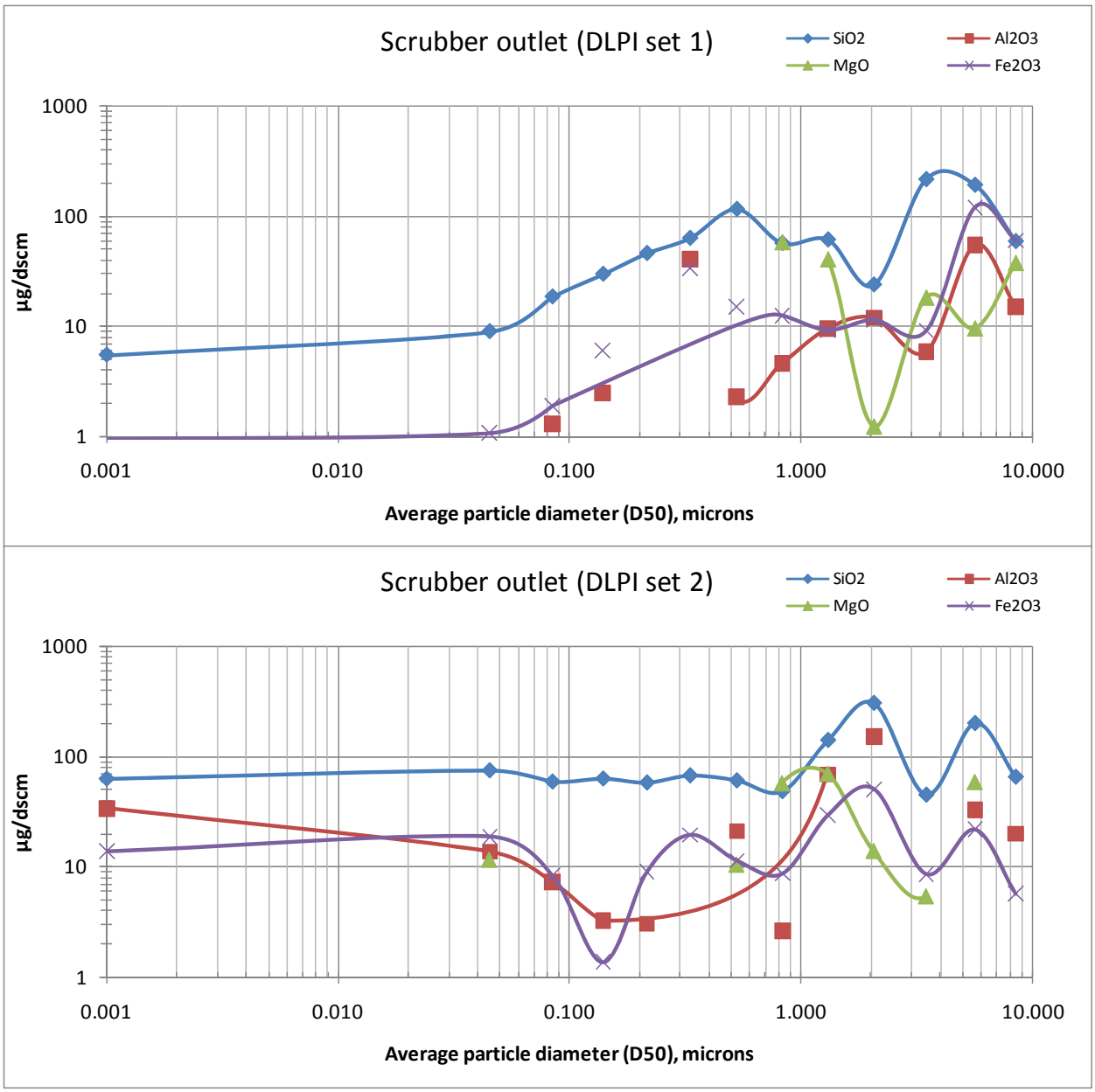


Figure 22. Silicon, aluminum, magnesium and iron concentrations as a function of average particle diameter in scrubber outlet samples.

Comparison of the mass of the particles in terms of composition is shown in **Figure 23**. The results show that sodium and potassium are reduced across the ESP. However, no reduction of sodium and potassium was observed across the scrubber. This is consistent with other scrubbers operating globally.

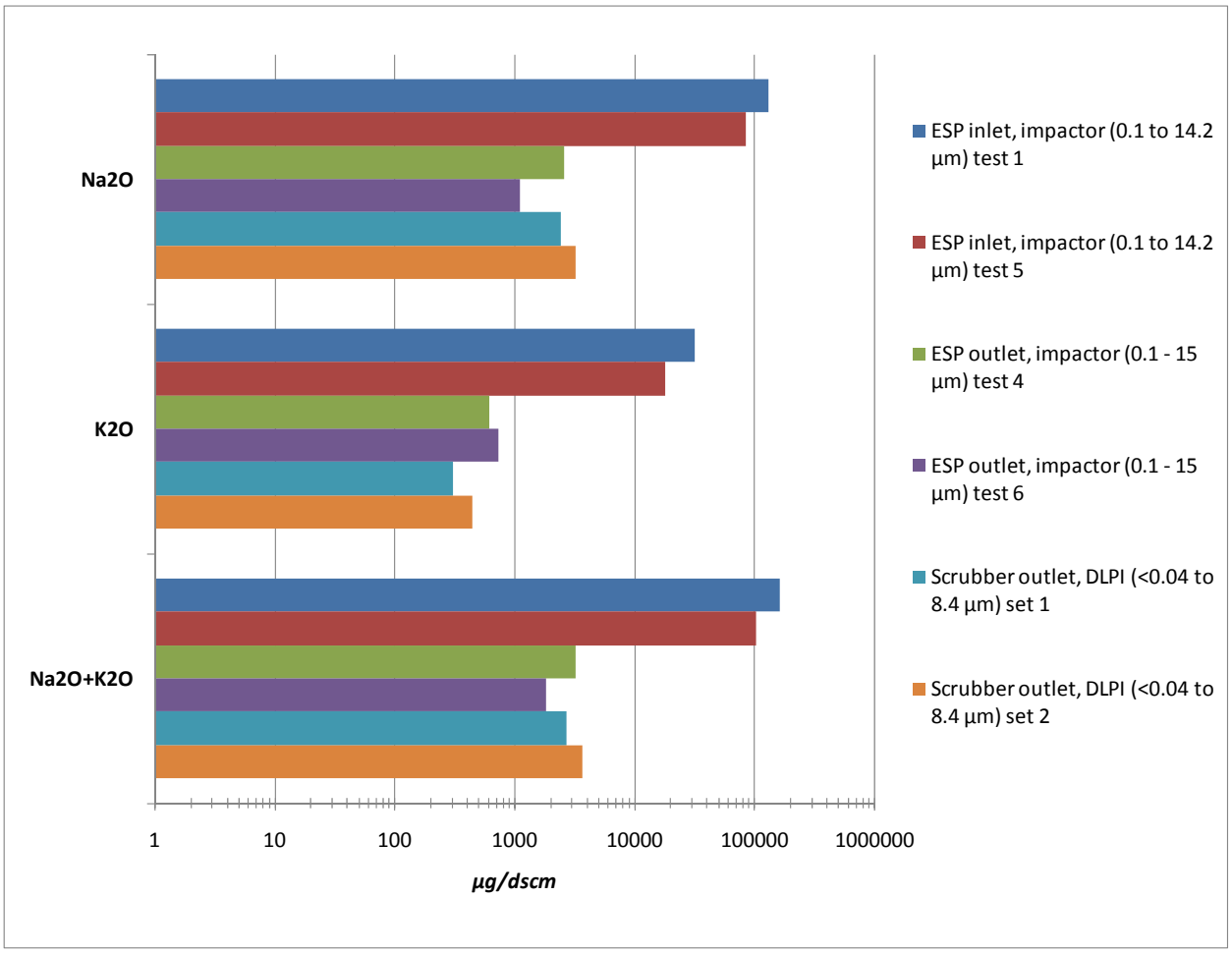


Figure 23. Mass of sodium and potassium oxide in the flue gas upstream and downstream of air pollution control devices at MRY.

SUMMARY AND CONCLUSIONS

Particulate sampling was conducted at Minnkota Power Cooperative's Milton R. Young plant to determine the particulate size and composition distribution of samples collected upstream of the ESP, upstream of the wet scrubber, and downstream of the wet scrubber. Emphasis was placed on determining the fate of sodium, potassium, and calcium since these elements can cause significant plugging and deposition problem.

During the testing, operating conditions of the plant were constant and there was no gas bypass. The coal fired during the testing remained relatively consistent. The as-received ash content ranged from 7.73 to 7.89%. Sodium oxide content of the ash ranged from 7.22 to 7.57% and the base-to-acid ratio decreased the last two days of testing (a result of a decrease in CaO content and an increase in SiO_2 and Al_2O_3 levels). Sampling upstream of the ESP and scrubber were conducted using a combination multicylones and impactors. The cyclones collected sized fractions of larger particles (greater than one to five microns) and the impactor collected the sub-micron particulate. Sampling downstream of the scrubber was conducted with a single cyclone followed by a 13-stage advanced impactor. In addition, the submicron particle number concentration was measured using a scanning mobility particle sizer (SMPS).

The results of the particulate mass information indicated a high loading at the ESP inlet of 4.96×10^6 µg/dscm, a scrubber inlet loading of 1.1×10^4 µg/dscm, and a scrubber outlet loading of 1.08×10^4 µg/dscm. These results show very little overall removal of the submicron particulate across the wet scrubber system. A significant fraction of the particulate was removed by the ESP, with a removal efficiency of 99.76%.

The size distribution of the particulate collected upstream of the ESP and upstream of the scrubber was multi-modal as summarized below:

- Upstream of the ESP there were at least three modes – a larger mode at 40 to 50 µm, a second mode at just under 10 µm, and third mode at about 1 µm. The larger particles are typically derived from mineral grains in the coal such as quartz, clays, and pyrite. The intermediate-sized particles are typically derived from small minerals and organically associated elements. The smaller mode (about one-micron and smaller) contains fine particles and condensed vapor phase species.
- Upstream of the scrubber there were two distinct modes – a larger mode between 8 to 10 µm and another mode centered at about 1 to 2 µm in diameter. The smaller mode is typically condensed vapor phase and small particles.
- Downstream of the scrubber, the primary mode centered at about 0.5 to 0.7 µm, and another possible mode occurred at 3 µm and larger.
- Particle number distributions were as follows:
    - Inlet to the ESP – between 1×10^7 to 10^8 particles per dry normal cubic centimeter (dncc);
    - Inlet to the scrubber is 10^5 particles/dncc;
    - Outlet of the scrubber 7×10^5 particles/dncc.
- Particle number distributions into the nanometer scale (1 µm = 1000 nm) was found to be as high as 10^5 particles/dncc.

Particle composition distributions of the particulate were determined for each of the major elements. The results were reported as μg/dscm of the element as illustrated in the Appendix and in the figures in the text.

- Upstream of the ESP the composition trends for sodium, potassium, calcium and sulfur showed greater concentrations of these elements in the particles that are smaller than 10 μm, with a significant increase in concentration in the flue gas at a particle size of less than 2 μm. There is another increase at 0.1 μm.
- Upstream of the scrubber the compositional trends for sodium, potassium, calcium and sulfur show higher levels at the 1 μm level. The ESP was effective in removing larger-sized particles, as well as some of the 0.1 μm particles. However, in the intermediate 1 μm particles, the ESP is not as effective in removing the particles.
- Downstream of the scrubber the composition size distribution determined for sodium, potassium, calcium and sulfur showed significant levels of sodium and sulfur in size fraction finer than 1 μm. The DLPI sampling system provides very accurate sizing data in the submicron size range. Other elements such as aluminum, silicon and iron show a significant depletion below 1 μm.

Comparison of the characteristics of the particles in terms of mass and composition indicate that, at the time of the testing, the total average mass of the particulate was about 10,800 μg/dscm. The particulate consisted mainly of sodium, potassium, and sulfur. The total quantity of sodium and potassium exiting was between 2000 to 3000 μg/dscm.

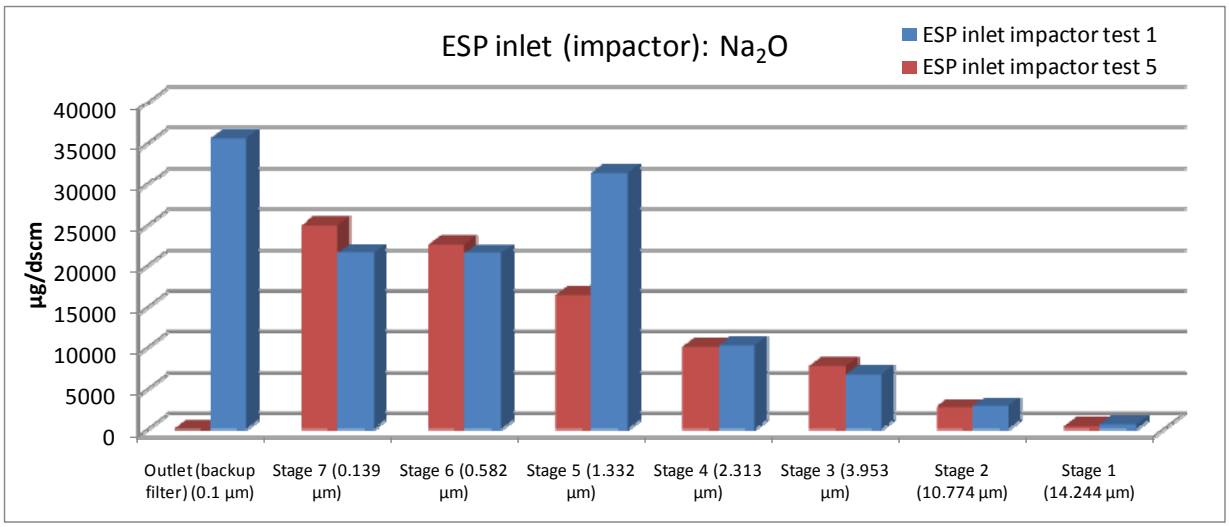


Figure A-1. Sodium concentration by sample stage (average diameter in microns).

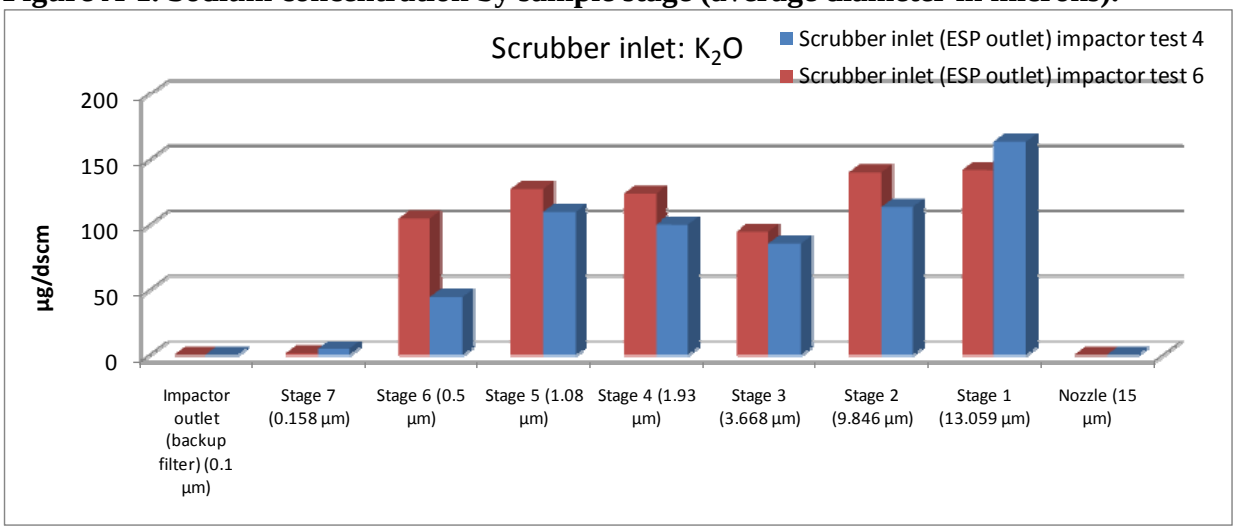


Figure A-2. Potassium concentration by sample stage (average diameter in microns).

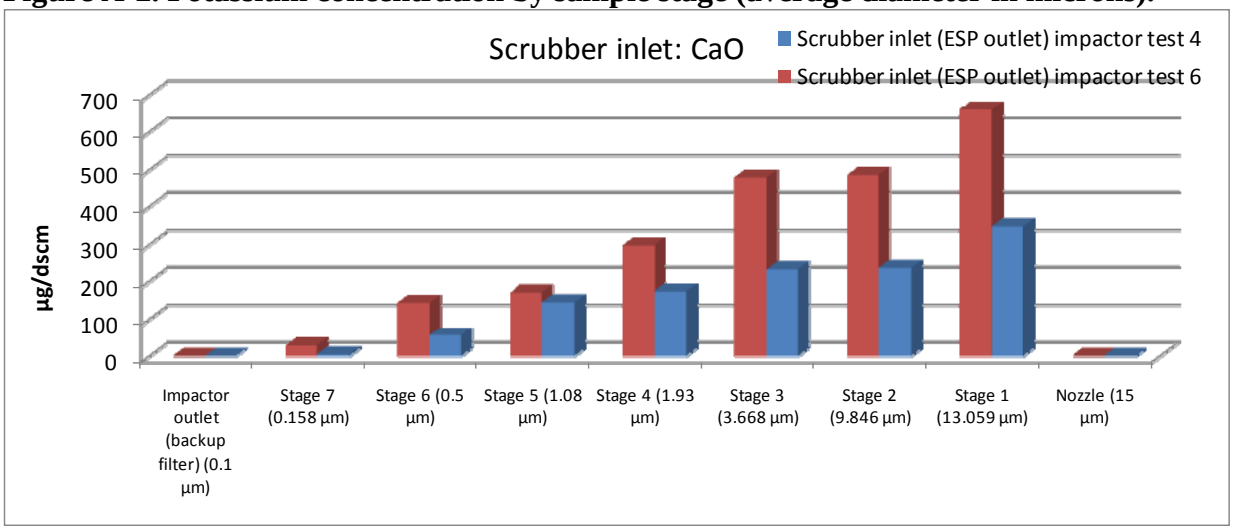


Figure A-3. Calcium concentration by sample stage (average diameter in microns).

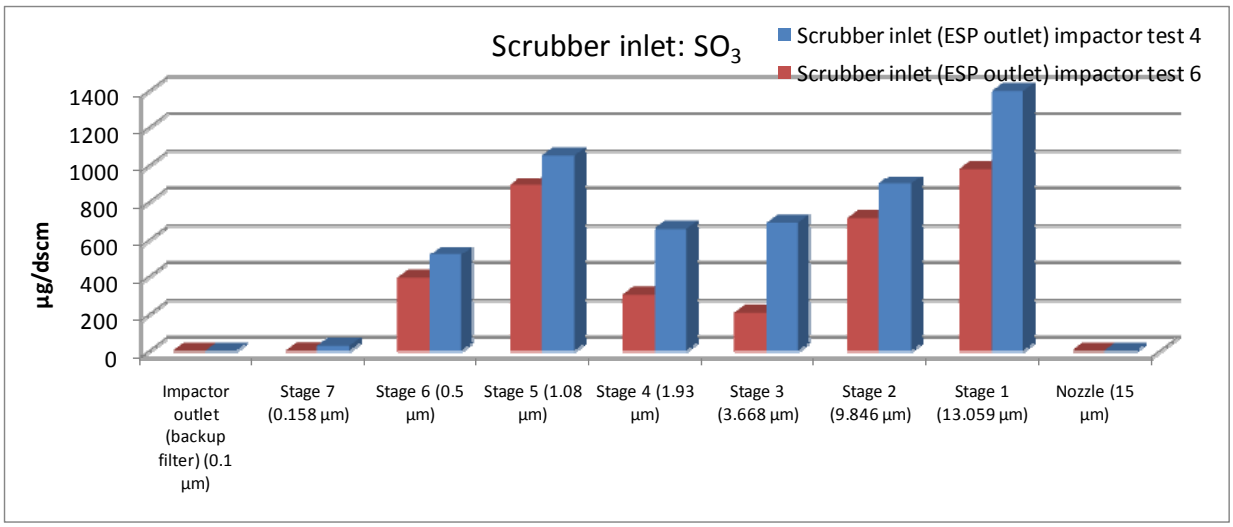


Figure A-4. Sulfur concentration by sample stage (average diameter in microns).

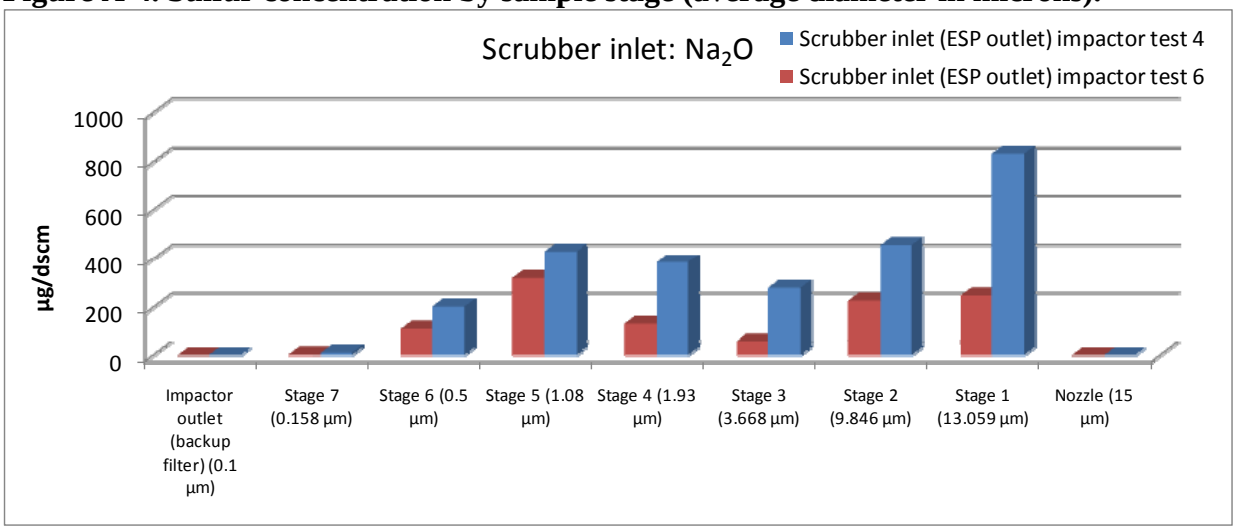


Figure A-5. Sodium concentration by sample stage (average diameter in microns).

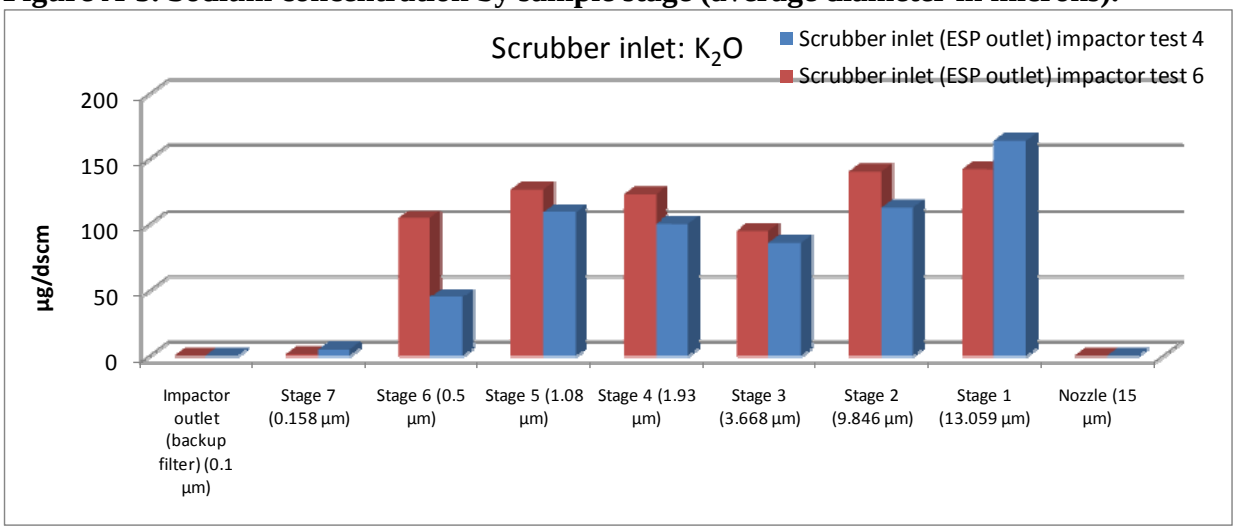


Figure A-6. Potassium concentration by sample stage (average diameter in microns).

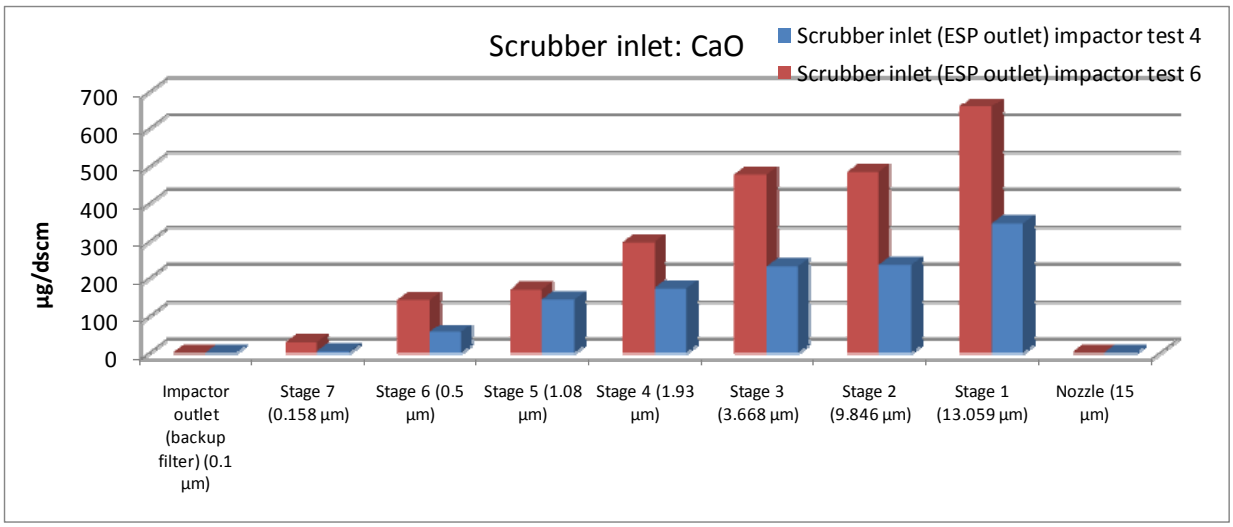


Figure A-7. Calcium concentration by sample stage (average diameter in microns).

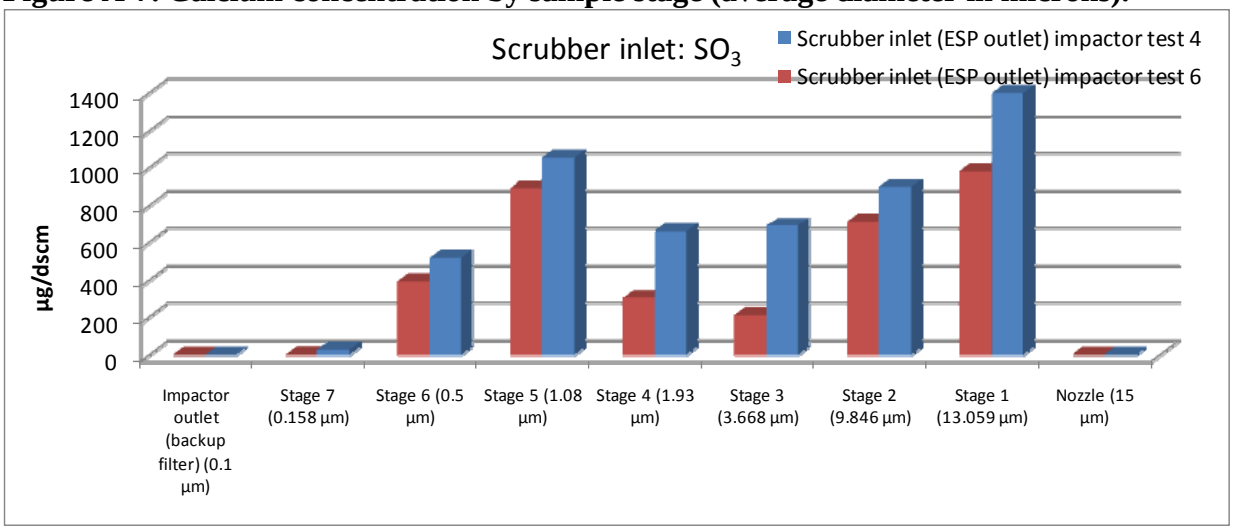


Figure A-8. Sulfur concentration by sample stage (average diameter in microns).

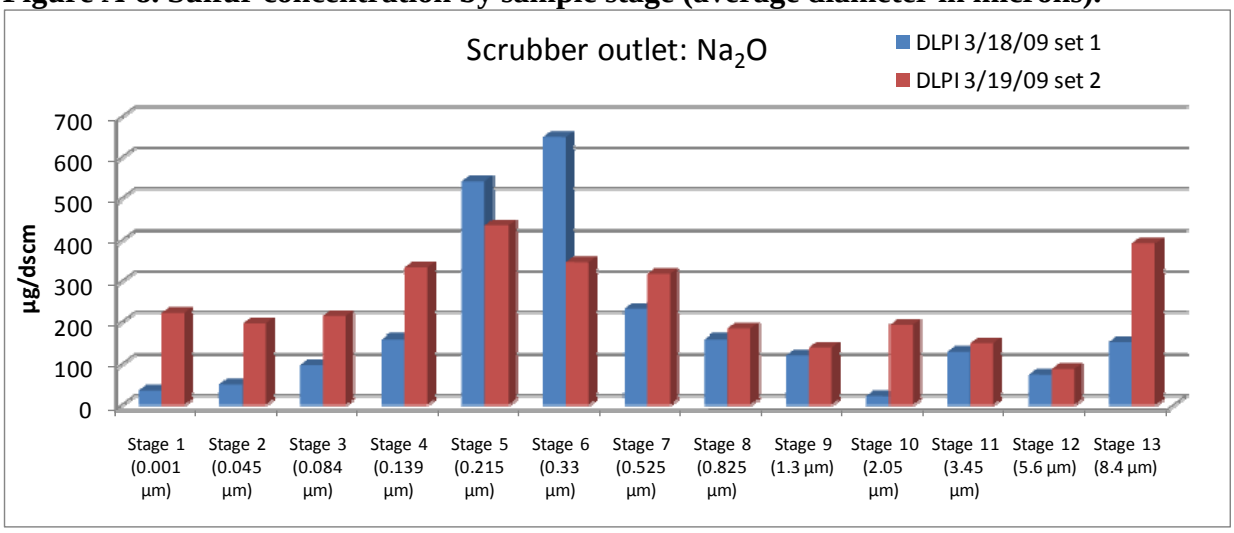


Figure A-9. Sodium concentration by sample stage (average diameter in microns).

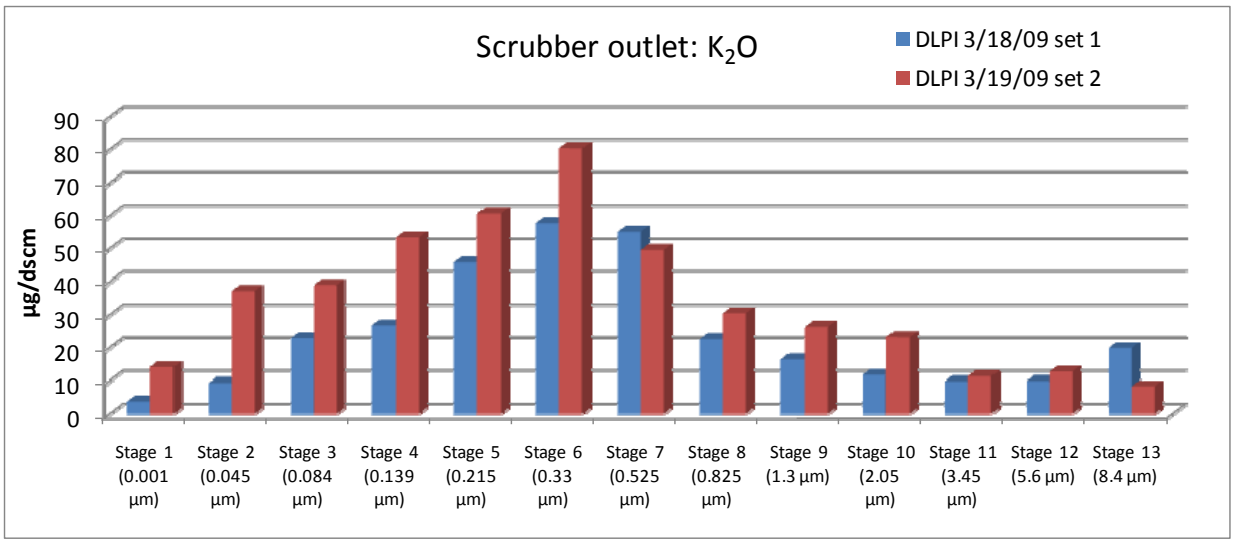


Figure A-10. Potassium concentration by sample stage (average diameter in microns).

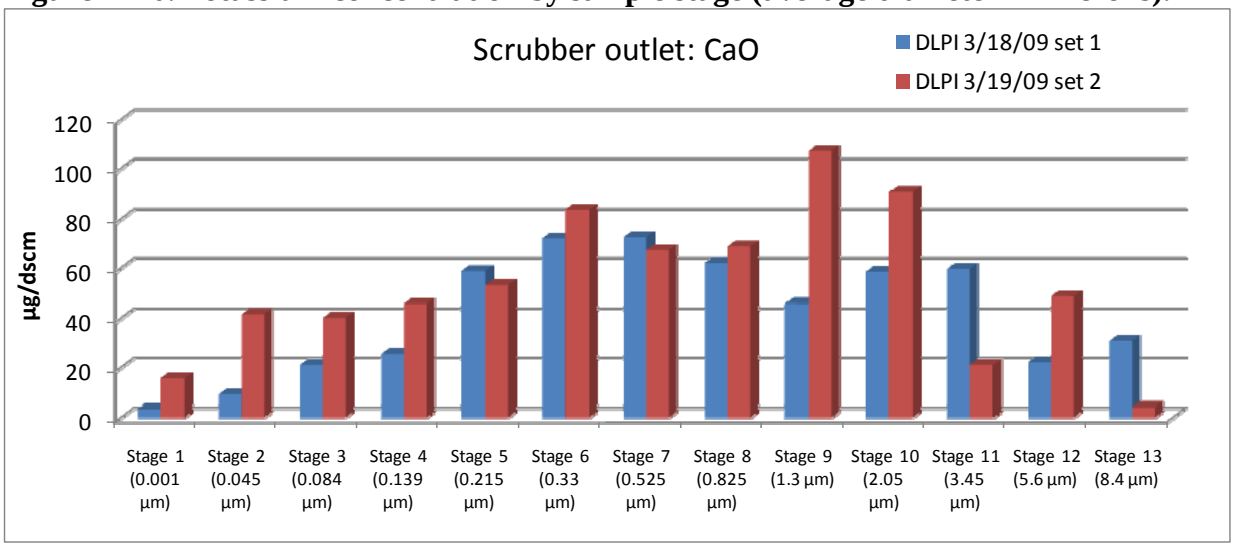


Figure A-11. Calcium concentration by sample stage (average diameter in microns).

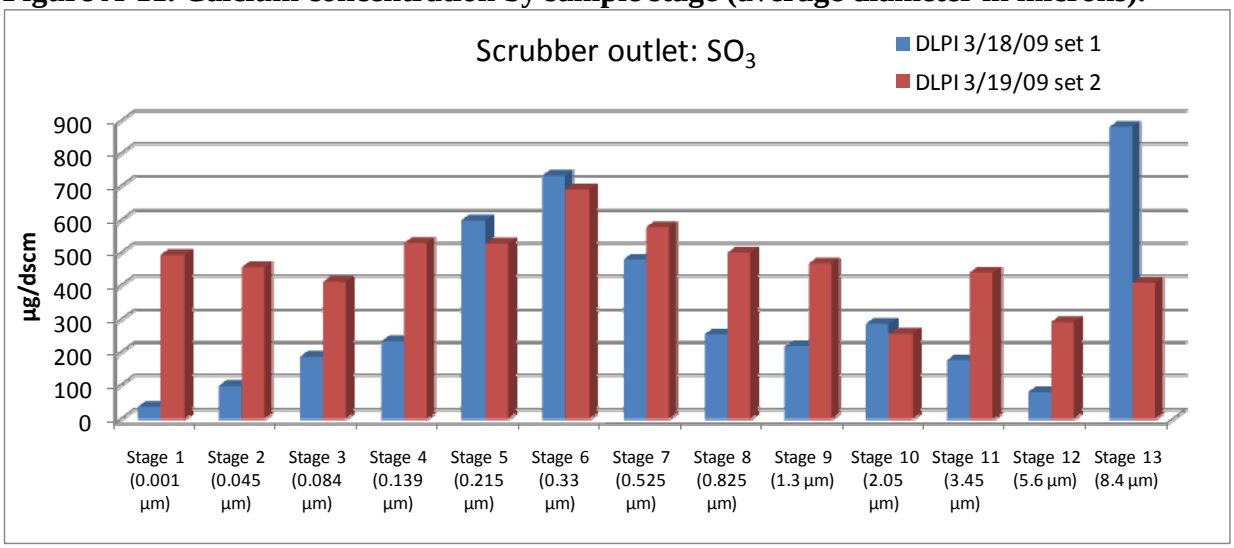


Figure A-12. Sulfur concentration by sample stage (average diameter in microns).

Temperature

The temperature in the field during this test was approximately 24°F. This made it very difficult for the equipment to start and warm up to normal operation conditions, especially the CPC. With the help of a fish tent, carpets, and small blow heaters, the CPC was brought to normal operating temperature. Because of the cold conditions, there was a significant condensation issue in the lines that fed the SMPS system. Although this problem was reasonably resolved for all lines from the probe end to the EC by applying heat/thermal tapes, the lines connecting the EC and CPC also had a buildup of condensed fluid to the extent that they had to be drained at one point to help stabilize the flow via the CPC pump.

Wind

Another challenge faced in the field was the high winds of more than 20 mph. With the scrubber outlet location being about 105 feet above the ground, such windy conditions constantly shook the grid and the equipment; thereby introducing turbulence to the flow through the CPC pump.

Pore Flue Gas Pressure

A more serious problem was the lack of adequate positive pressure from the sampling port to supply enough flue gas through lines into the SMPS system. This resulted in very low counts observed in many data sets. Although the sampling port at the scrubber outlet is at positive pressure, it probably was not high enough to feed enough flue gas through the small nozzle of the sampling probe to the SMPS system.

Milton R. Young Unit 2

MRY Unit 2 is a Babcock & Wilcox (B&W) Carolina-type radiant boiler designed to burn high-moisture, high-slagging/fouling North Dakota lignite. Nominally rated at 3,050,000 lb/hr, this unit is a cyclone-fired, balanced-draft, pump-assisted circulation boiler. The unit began commercial operation in May 1977 and is base-loaded at 470 MW gross. The unit is equipped with a cold-side ESP for particulate control and a wet FGD unit for SO_2 control. The cold-side ESP has a specific collection area (SCA) of 375 ft^2/1000 acfm. The wet FGD for SO_2 control utilizes alkaline ash and lime. The MRY Station fires North Dakota lignite coal from the Kinneman Creek and Hagel Seams at the Center Mine.

Form of Sodium in Center Lignite

Sodium is associated with the organic matrix in Center lignite. That means the sodium is atomically dispersed in the organic matrix. The sodium is associated with a carboxylic acid groups (ion exchange sites). The carboxylic acid groups act as bonding sites for various elements such as Ba, Ca, Mg, and Sr along with minor amounts of K. Figure C-1 illustrates the bonding of sodium to the organic fraction of the coal and the association of other coal impurities.

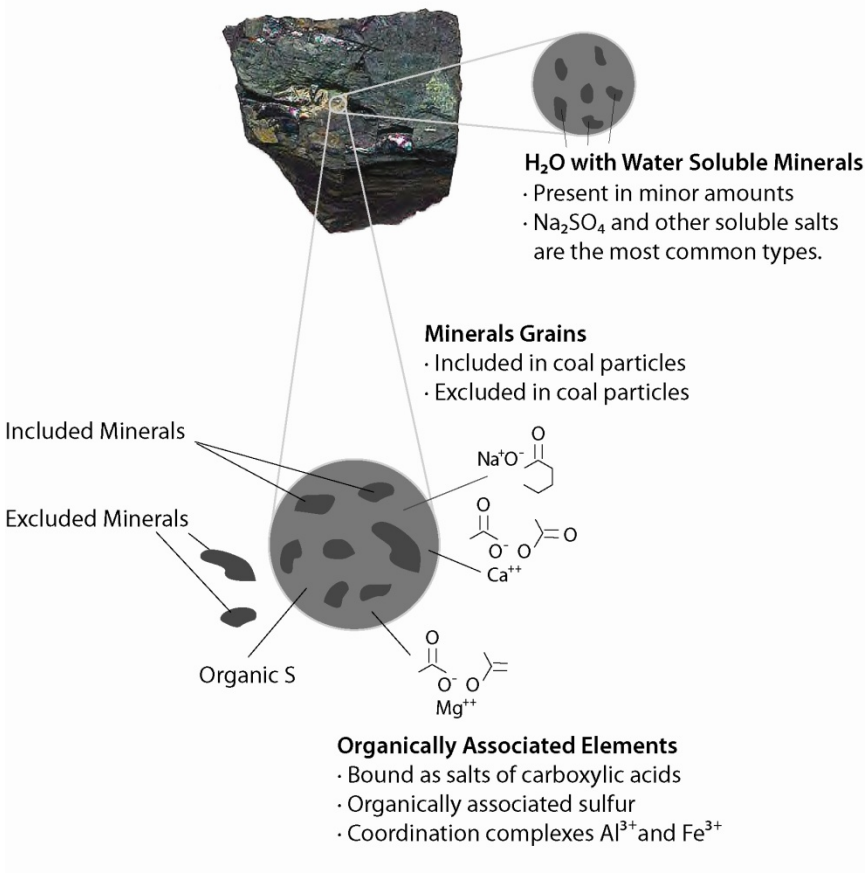


Figure C-1. Form of sodium in coal (Benson and Laumb, 2008).

Vaporization of sodium in PC and cyclone-fired systems

Sodium is a volatile element and will be transformed into a gas upon combustion. The vaporization of sodium during the combustion of lignite is a very well known fact that has been examined by numerous investigators; include work conducted by MIT, CalTech, Sandia National Laboratory, National Energy Technology Laboratory, University of Utah, and others. For example, research conducted by Senior and others (2000) reported that relative to other coals, North Dakota lignite produced more vaporized ash. The actual amount vaporized for ND lignite is double the level vaporized as compared to subbituminous and lignite coals from Montana as illustrated in Figure C-2. Work conducted at the MRY plant related to the vaporization of sodium from a cyclone fired systems is illustrated in Figure C-3. The results show over two thirds of the sodium is not retained in the slag and is vaporized.

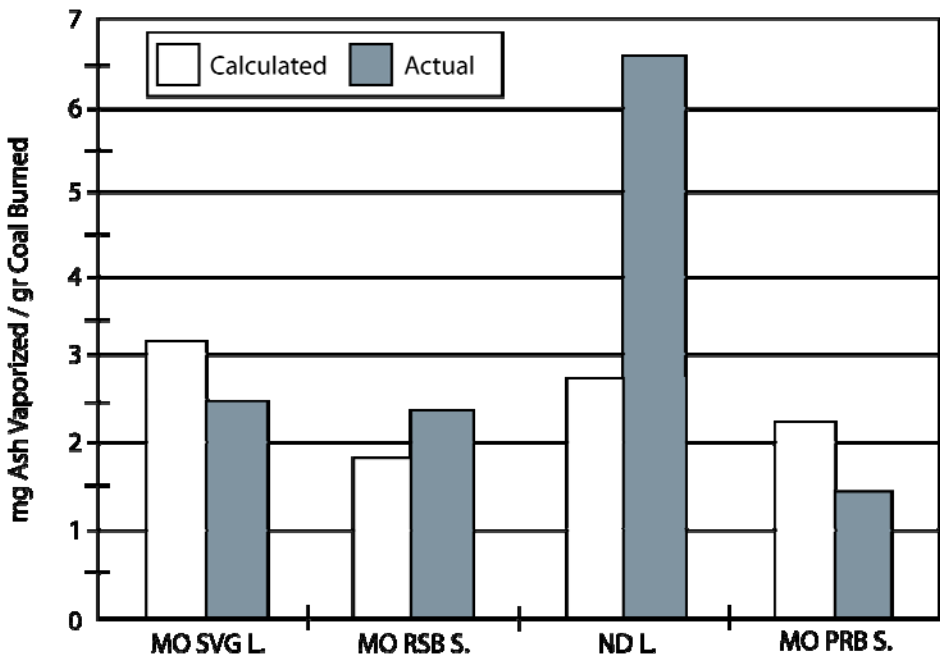


Figure C-2. Ash vaporized during combustion of lignite and subbituminous coals (Senior and others, 2000).

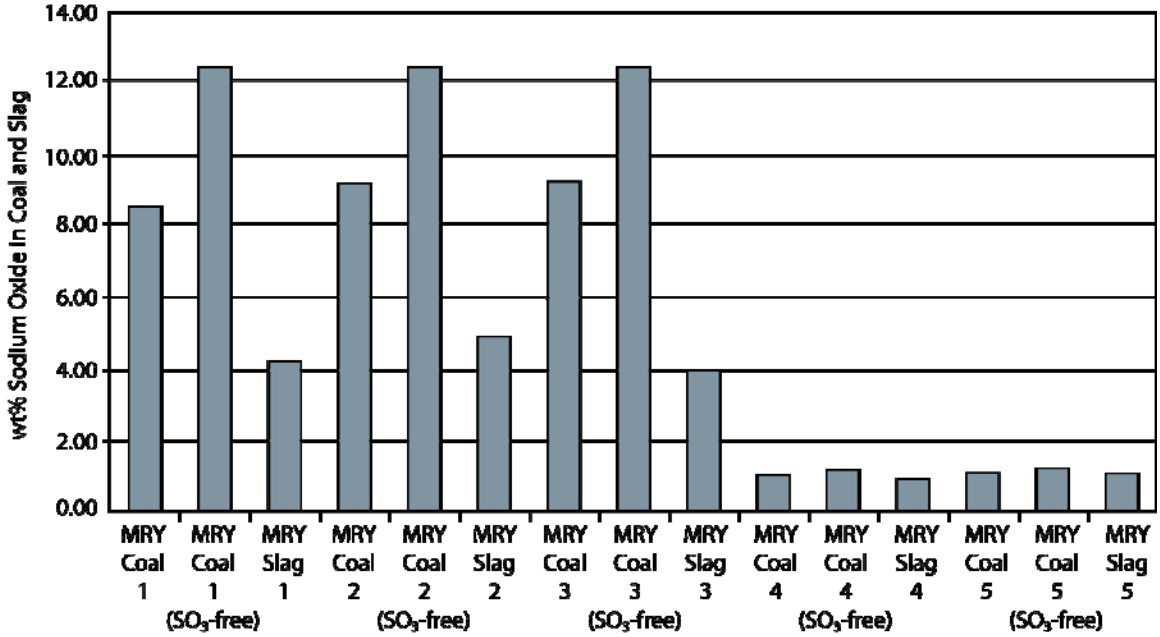


Figure C-3. Comparison of sodium levels in Center lignite coal and slag samples.

Condensation of vaporized species to form aerosols

EPA has evaluated the literature on particle formation during combustion and from other sources and incorporated it into an educational module that can be found on the following website (http://www.epa.gov/apti/bces/module3/formation/formate.htm). The classification of particle types shown by EPA is illustrated in Figure C-4. The EPA classification is consistent with the review conducted by Lighty and others (2000). Vaporized species can condense heterogeneously on surface of other entrained coarse ash particle and can condense homogeneously to form the fine and ultrafine particles. The distribution of particles depicted in Figure C-4 is shown on a frequency percent of particles by mass basis. The particle number versus size is also important and a comparison of the number of particles and particle size is summarized in Table C-1. The number of aerosol particles is significant. These particles have high surface areas and are very reactive.

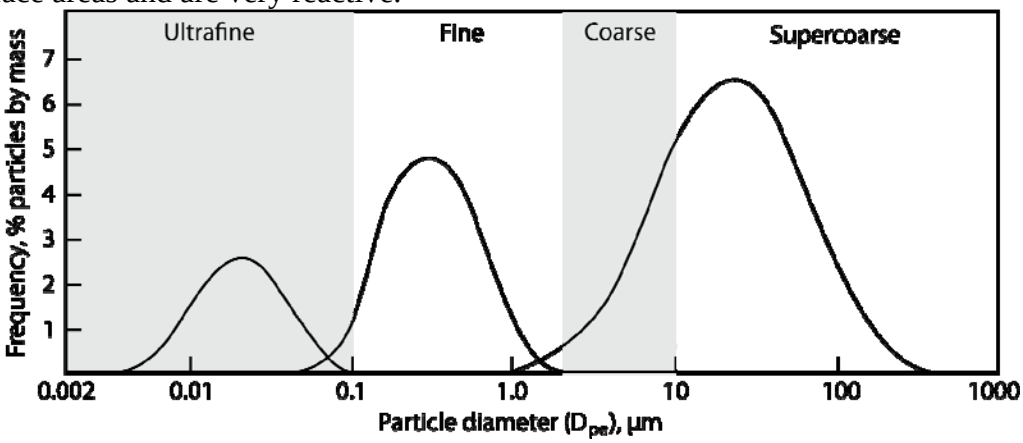


Figure C-4. Particle size categories used to classify particles (http://www.epa.gov/apti/bces/module3/category/category.htm)

Table C-1. Particle size, number of particles, and surface area[1] (http://www.epa.gov/apti/bces/module3/category/category.htm)

Total Mass	Diameter of Particles (µm)	Number of Particles (Approx. in millions)	Total Surface Area (cm^2)	Total Surface Area (m^2)
1.0 gm	1,000	1.002	60	1.006
	100	2	600	0.06
	10	2,000	6 000	0.6
	1	2,000,000	60,000	6
	0.1	2,000,000,000	600,000	60

(1) Based on density of 1.0 gm/cm^3

Figure C-5 provides a comparison of the mass distribution and particle number distribution. As the particle size decreases the number of particles in the size fraction increases. In addition, as illustrated in Table C-1, the surface area increases significantly with decreasing particle resulting in the opportunity for reactive gases such as sulfur oxides to react forming sticky phases that bond particles together.

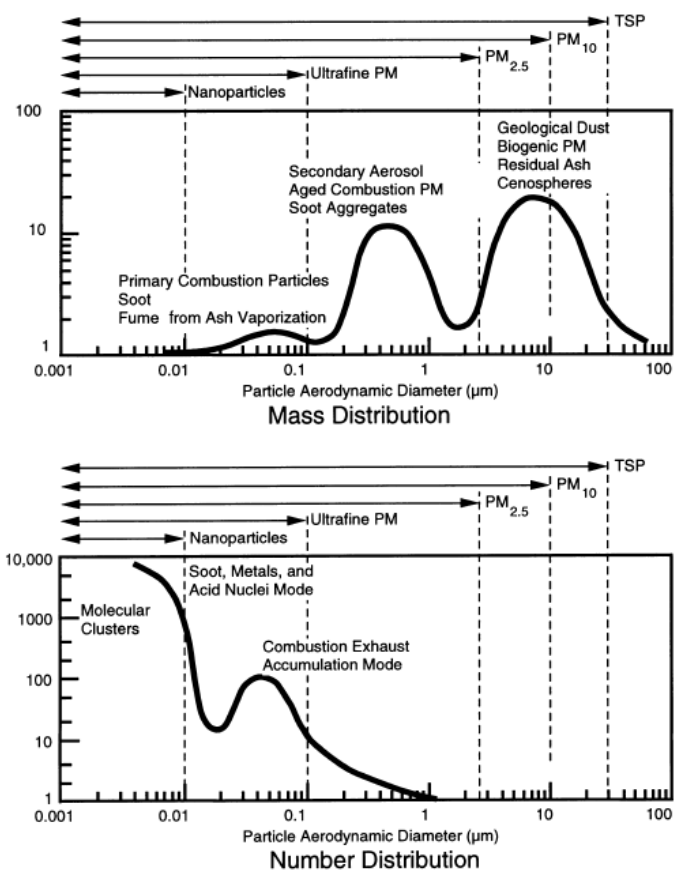


Figure C-5. Comparison of mass distribution and particle number distribution for combustion derived particles and aerosols (Lighty and others, 2000).

Particle size distributions for fly ash collected upstream and downstream of an ESP are illustrated in Figure C-6. This work was conducted by Markowski and others (2000) specifically aimed at characterizing the submicron aerosol mode of fly ash formation.

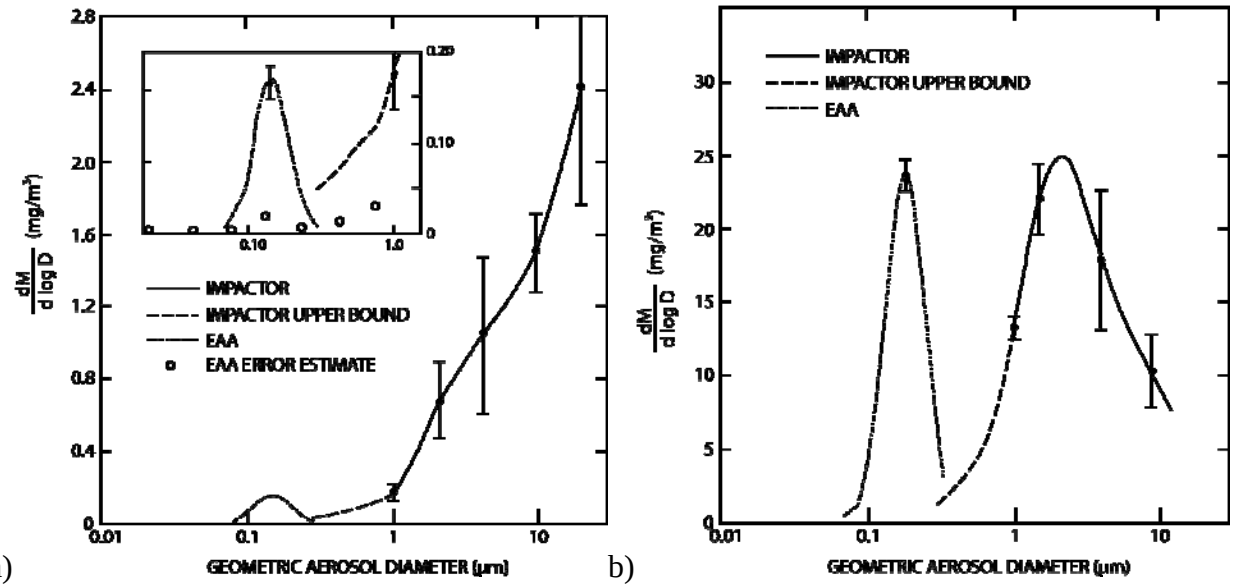


Figure C-6. Typical differential mass distributions of particulate collected a) upstream and b) downstream of an ESP (Markowski and others, 2000).

Fly ash produced upon the combustion of high sodium lignites in a pulverized coal (PC) fired system shows significant enrichment of sodium in the smaller size fractions as shown in Figure C-7. This figure illustrates the increase in the sodium content in the finer size fractions of ash as a result of firing high sodium lignite. The sodium and sulfur content of the less that 3 micrometer size fraction of the sampling train approached 20% Na_2O, and 25% SO_3. The form of the sodium is likely sodium oxide and sulfate.

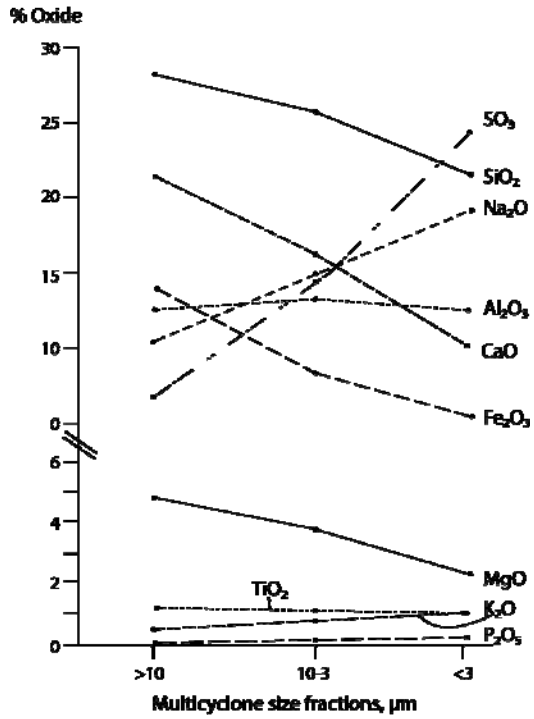


Figure C-7. Composition distribution of ash particles during combustion of North Dakota Lignite (Benson and others, 1984).

Electrostatic precipitator collection efficiency

The classical curve for ESP particle collection efficiency is shown in Figure C-8. This curve is typical of well behaved ash materials that do not present significant problems in collection. The collection efficiency is very good for particles greater than 5 to 10µm and the collection efficiency decreases with decreasing particles size with minimum collection efficiency between 0.2 to 2 µm in diameter. The collection efficiencies vary significantly because of particle size and composition.

Low collection efficiency for difficult to collect particles is between 0.1 to 1 µm in particle diameter. Figure C-9 provides an illustration of the range of collection efficiencies. Based on EPA education modules, no air pollution control device shows high collection efficiency in this range (0.1 to 1.0 µm) due to inherent limitations of the collection devices and particle characteristics (http://www.epa.gov/apti/bces/module3/collect/collect.htm). The following mechanisms of particle capture are impacted by the size of the particles:

- Inertial impaction and interception
- Brownian diffusion
- Gravitational settling
- Electrostatic attraction
- Thermophoresis
- Diffusiophoresis

The EPA (http://www.epa.gov/apti/bces/module3/collect/collect.htm) has indicated that based on a number of studies of actual "*sources stationary sources generating high*

concentrations of particles in the 0.1 to 0.5 micrometer range may be an especially challenging control problem. … The gap is most noticeable in wet scrubbers and electrostatic precipitators." A generalized plot showing the range of collection efficiencies is shown in Figure C-9. Overlaid on the diagram is the mass size distribution of particles collected downstream of the ESP wet FGD at the MRY plant (Markowski and others, 1983). This shows that ash produced in the MRY plant have a particle size that can pass through the scrubber and that these particles are rich in sodium as shown in Figure C-7.

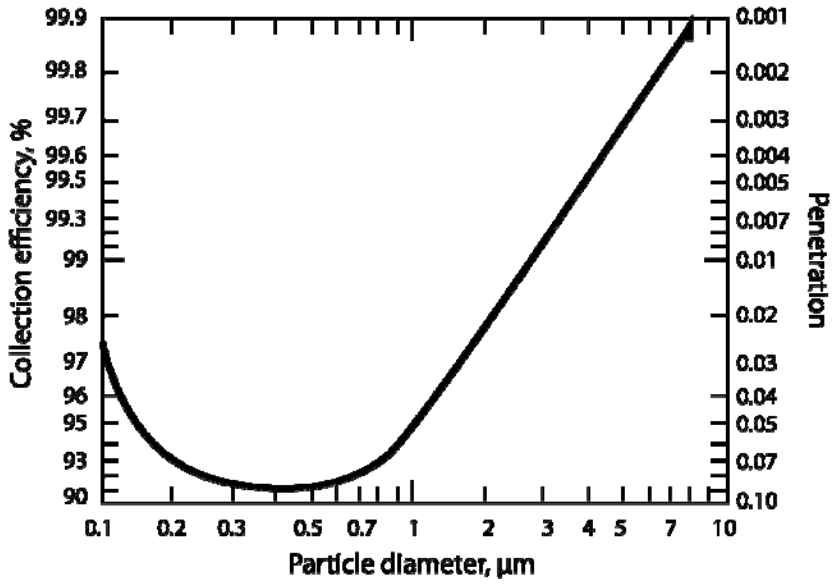


Figure C-8. Typical ESP Collection efficiency curve for removal of particulate from gas streams (http://www.epa.gov/apti/bces/module3/collect/collect.htm).

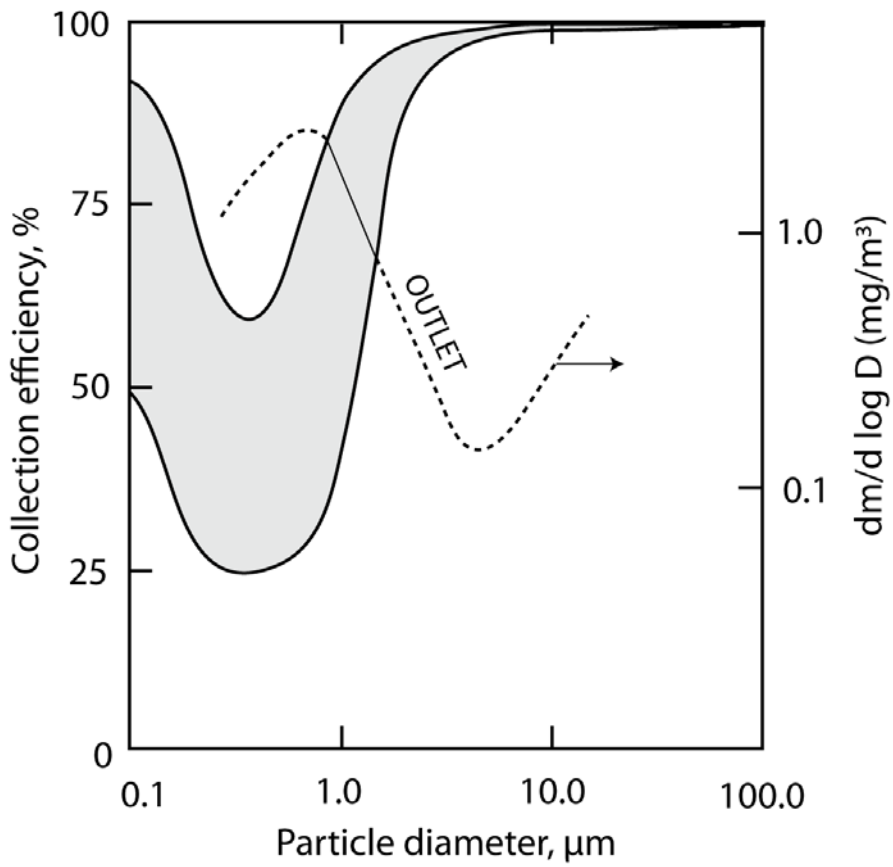


Figure C-9. Particulate control efficiency for difficult to control particulate combined with the mass distribution of particulate collected downstream of the scrubber at MRY (Markowski and others, 1983, http://www.epa.gov/apti/bces/module3/collect/collect.htm)

Field Experience and Testing

As indicated by EPA (Woodward, 1998), scrubbers do not effectively remove particulate less than 1µm in diameter. There is significant evidence that sodium-rich aerosols penetrate ESPs as well as scrubbers at full-scale power plants when firing high-alkali-containing fuels. An example is a biomass fired system using a tower type scrubber where the removal efficiency of the smaller size fraction of ash is low, as shown in Figure C-10 (Ohlström and others, 2006).

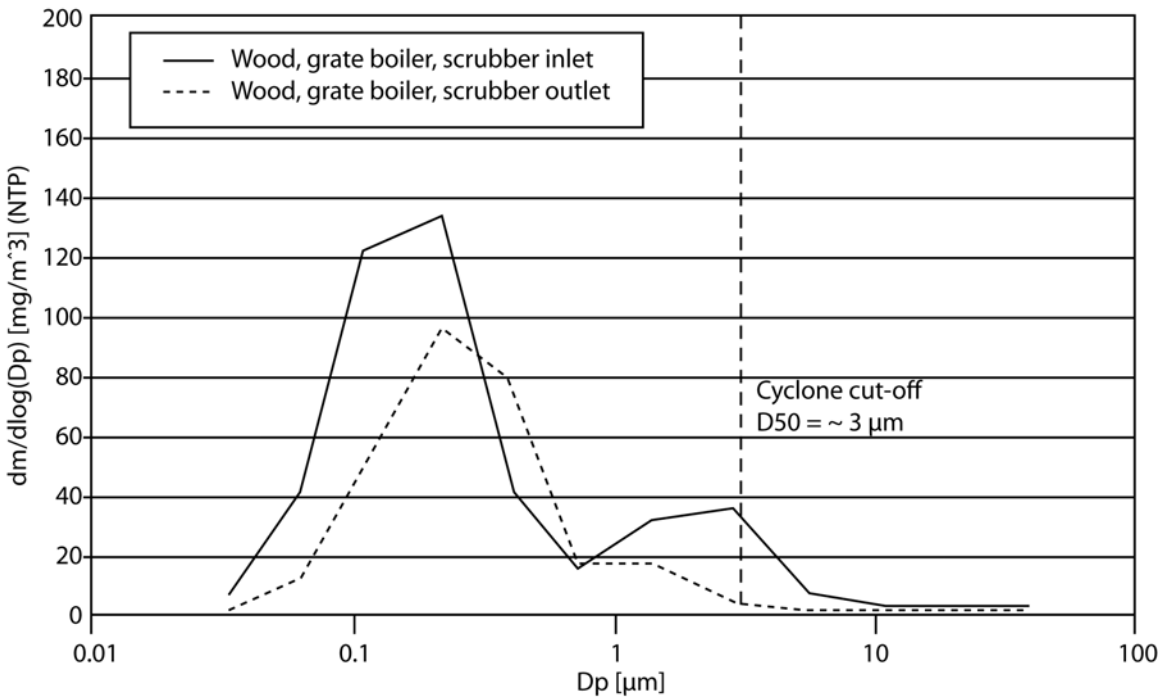


Figure C-10. Removal of fine aerosols using a scrubber on a wood fired combustor (Ohlström and others, 2006).

Minnesota Power's Boswell Energy Station found that when it fired high-sodium, lower-ash northern Powder River Basin subbituminous coal (7% Na_2O in the ash), it experienced increases in opacity. Hurley and Katrinak (1992) conducted a field-testing project on Unit No. 4, a pulverized coal-fired boiler equipped with a venturi wet scrubber, to better understand the reasons for the opacity problems. During the field testing, sampling of the coals, flue gases, and scrubber materials was conducted. The particulate in flue gases downstream of the scrubber was aerodynamically classified using multicyclone followed by an impactor and a Nucleopore filter. The sized fractions were weighed and analyzed to determine the abundance and composition of the submicron-sized fractions. The mass loadings in the various size bins are plotted in Figure C-11, showing that the scrubber is quite effective in removing the larger particles. However, the scrubber is not very effective in removing the aerosols less than 1 micrometer in diameter for both the blended coal and the high sodium coal (Coal A).

The results of the study indicated that the particulate collected downstream of the scrubber was coal-related and caused by the high sodium content of the coals. Vapor-phase sodium condenses in the boiler's convective pass to form fine sodium-rich aerosols or other Na species that later react with ash particles. Pure Na_2SO_4 particles are too small to be removed by such scrubbing. Figure C-12 shows the spikes of the ash material collected on Stage 10 of the impactor. This impactor accumulation represents particles of less than 0.7 to 2.5 micrometer size fraction of the submicron aerosol. The spikes are made up of submicron particulate matter, and the chemical analyses of the spikes and ash particles collected on the Nucleopore filters downstream of the impactor plates are shown in Table C-4. Both samples are dominated by sodium and sulfur that are likely in the form of sodium sulfate. These sulfate materials exhibit highly cohesive tendencies.

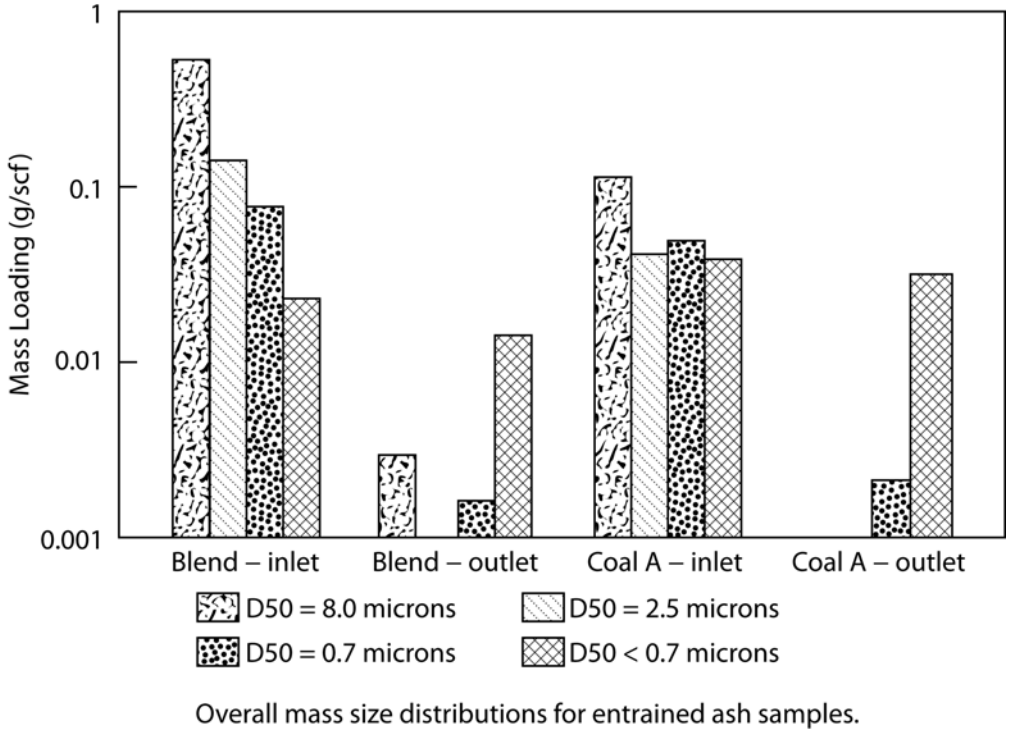


Figure C-11. Mass loadings and size for particulate collected upstream and downstream of the wet venturi scrubber at Clay Boswell (Hurley and Katrinak, 1992).

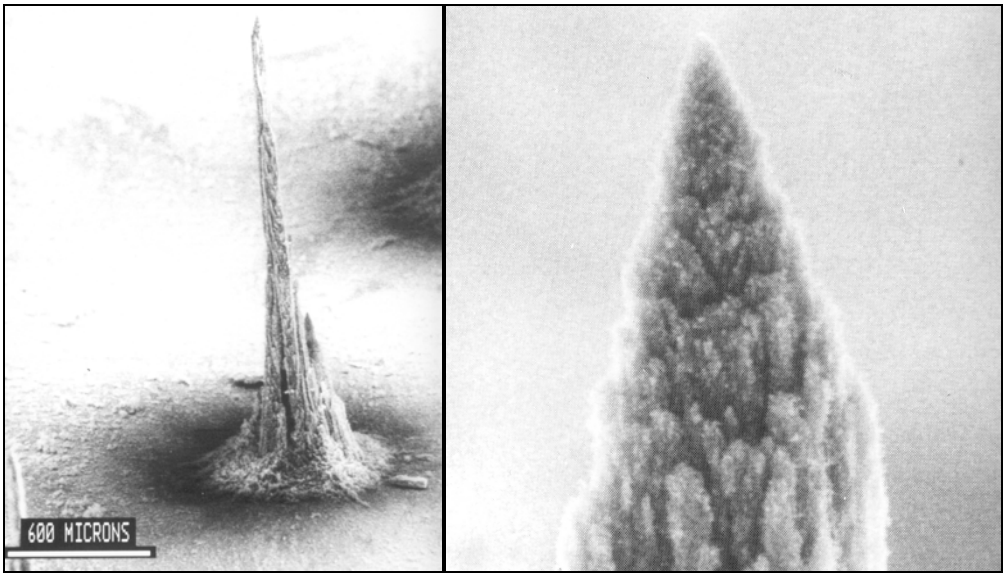


Figure C-12. Scanning electron microscope images of spike formed on impactor plate upon combustion of high-sodium subbituminous coal (right - close-up of spike) (Hurley and Katrinak, 1992).

Table C-4. Chemical Composition of the Spike Shown in Figure C-12 and the Filter (weight percent expressed as equivalent oxide).

	100% Coal A	
Oxide	Spike	Filter
Na_2O	**35.1**	**17.3**
MgO	1.4	7.8
Al_2O_3	2.0	9.8
SiO_2	9.1	10.6
P_2O_5	0.4	0.2
SO_3	**39.7**	**28.0**
K_2O	2.6	1.5
CaO	6.2	15.7
TiO_2	0.2	1.8
Cr_2O_3	1.4	0.1
Fe_2O_3	0.9	2.9
BaO	0.5	2.6

In addition to the aforementioned testing results, penetration of submicron particles through ESP and scrubbers has been reported by numerous researchers (Markowski and others, 1983, and Lighty and others, 2000).

Power Span Testing at MRY

Aerosols passing through the ESP at MRY Unit 1 resulted in significant accumulation on Powerspan's ECO barrier discharge reactor resulting in significant degradation in performance. The ECO DBD reactor is located just downstream of the plant's ESP or fabric filter (FF) and can be exposed to aerosols. The DBD reactor has quartz electrode rods inside where electric current is passed in order to generate the plasma used to oxidize NO. The temperature of the flue gas at the DBD reactor ranged between 300°F and 350°F. The temperature of the quartz electrodes is approximately 100°F higher than the gas temperature.

The Powerspan ECO reactor slip stream system was designed by Powerspan and the EERC. The slip stream system was installed by the EERC at Minnkota Power Company's Milton R. Young Station Unit #1 down stream of the ESP where the flue gas temperature was ranged from 300°F to 350°F. The system was commissioned on July 3, 2007, operated for 107 days. Operational performance of the system was monitored and data were archived for post processing. A pair of electrodes were extracted and replaced on a bi-weekly basis. Each pair of electrodes were shipped to Powerspan for testing in their laboratory reactor. Tested electrodes were then shipped to the EERC for scanning electron microscopy imaging and x-ray microanalysis. Measurement of NOx conversion by the slip stream system was not possible due to the nitric acid production of the DBD reactor.

The operational observations, performance results, and lab testing showed that the system was adversely affected by ash fouling. NOx conversion by ash covered electrodes was significantly reduced. Figure C-13 compares rods exposed to flue gas and aerosols downstream of the ESP at MRY Unit 1. The abundance of sodium in coal fired during the Powerspan testing is shown in Figure C-14. The results show sodium levels measured by the full stream elemental

analyzer (FSEA) ranged from 3.5 to 6 % Na2O in ash. Figure C-15 shows the degradation in NO conversion as a result of being coated with aerosols. The NO conversion was severely impacted.

Figure C-13. Comparison of (left) clean quartz rod and (right) dirty quartz rod exposed to flue gas downstream of ESP at MRY Unit 1 for sixteen days.

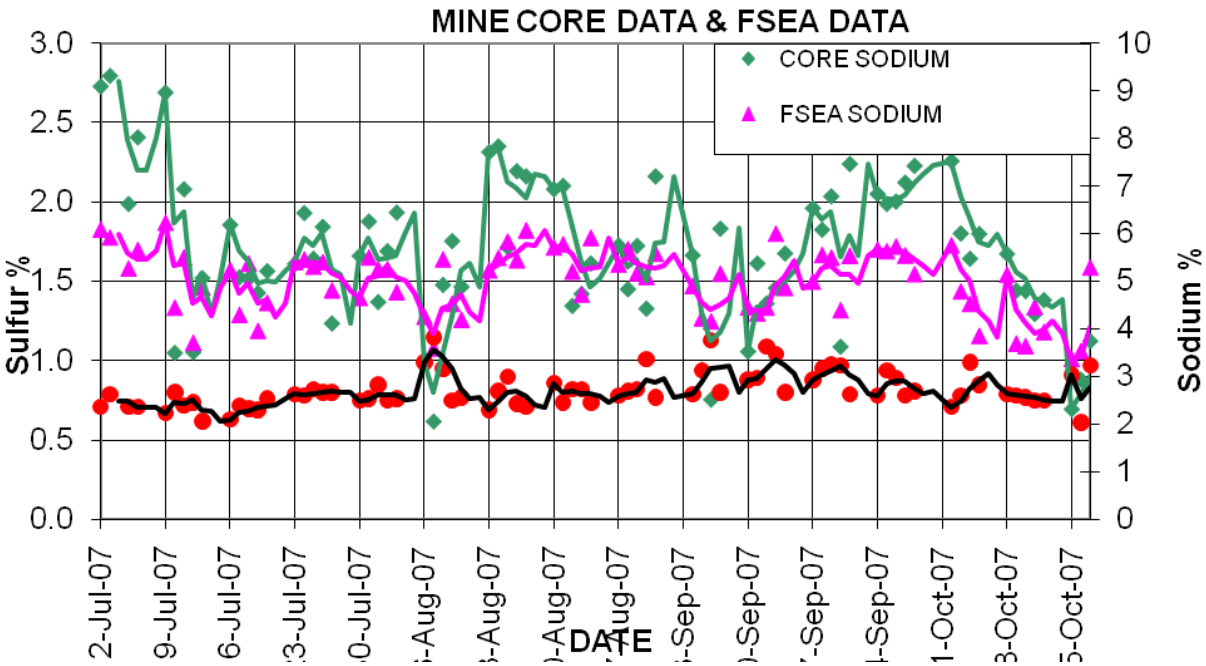


Figure C-14. Sodium and sulfur levels in lignite delivered during testing of the Powerspan barrier discharge reactor.

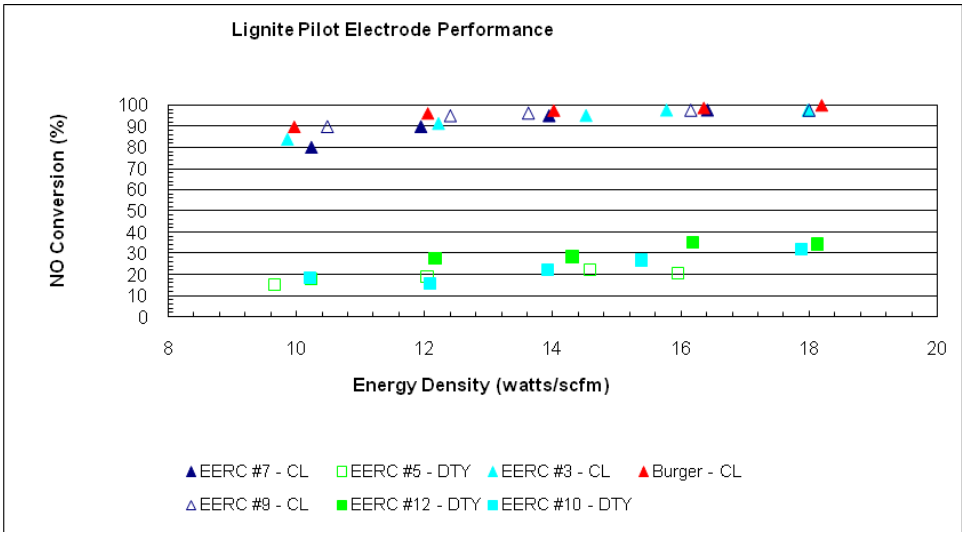
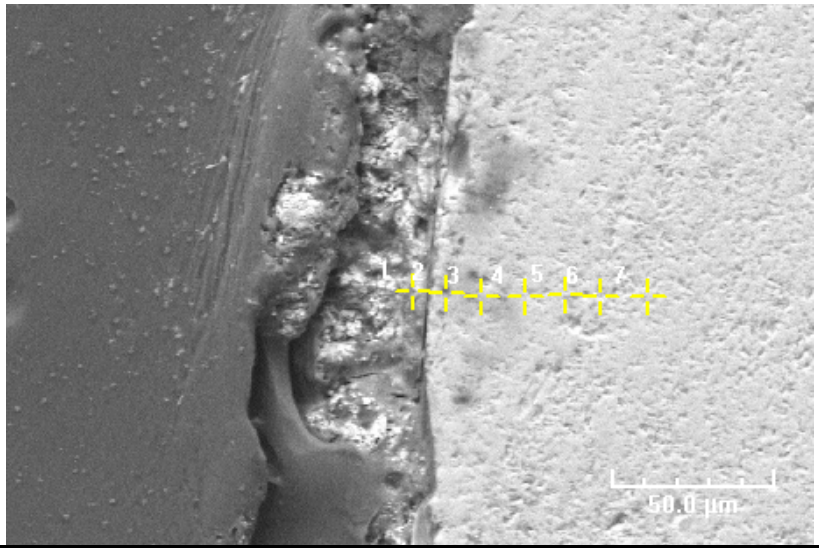


Figure C-15. NO conversion for clean (CL) and dirty (DTY) for quartz tube exposed the flue gas during the MRY testing.

Examination of the quartz rods (cross-sectioned to expose coating thickness) using scanning electron microscope elemental analysis showed significant elemental sodium, sulfur, and calcium in the ash coating the tubes after only 16 days of testing. The data is reported on Figure C-16. The thickness of the layer was approximately 25 µm. The rods were exposed to sootblowing. Images of the reactor and coatings on the electrodes are shown in Figure C-17.



Tag	Na	Mg	Al	Si	P	S	Cl	K	Ca	Ti	Fe	Ba
1	35.38%	0.98%	14.10%	4.68%	0.00%	35.75%	0.00%	1.42%	6.61%	0.02%	1.07%	0.00%
2	0.00%	0.00%	0.22%	98.52%	0.00%	0.00%	0.07%	0.89%	0.00%	0.30%	0.00%	0.00%
3	0.00%	0.00%	0.61%	98.11%	0.00%	0.00%	0.00%	1.05%	0.00%	0.00%	0.22%	0.00%
4	0.00%	0.00%	0.20%	98.33%	0.00%	0.00%	0.00%	1.19%	0.00%	0.00%	0.27%	0.00%
5	0.00%	0.00%	0.00%	98.70%	0.00%	0.00%	0.00%	1.24%	0.00%	0.00%	0.06%	0.00%
6	0.00%	0.00%	0.25%	97.26%	0.00%	0.00%	0.27%	1.70%	0.00%	0.00%	0.36%	0.16%
7	0.00%	0.00%	0.00%	97.93%	0.00%	0.00%	0.00%	1.55%	0.00%	0.00%	0.47%	0.05%

Figure C-16. SEM point analysis on electrode #11 (16 days of service).

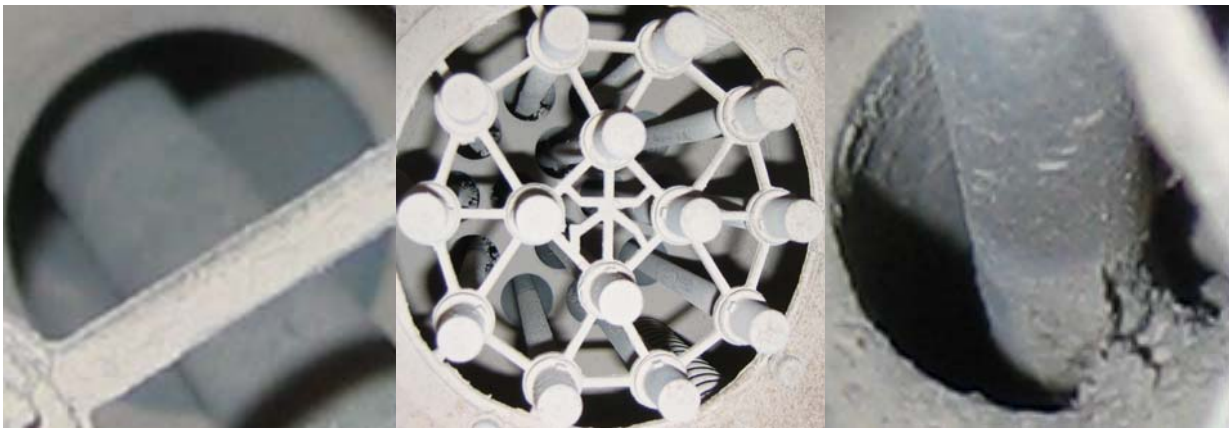


Figure C-17. Images of top of DBD reactor showing ash accumulations on electrodes and reactor surfaces.

Conclusions gained by this work were:

1. Sodium rich aerosols and small ash particles that had penetrated the ESP accumulate and become bonded on the surface of the silica electrodes in spite of soot blowing using a sonic horn as recommended by Powerspan.
2. Ash accumulations adversely affected the NOx conversion.
3. The adverse impact occurs within a two week time period.

MRY Sulfate Aerosol Sampling

The penetration of aerosols through ESP and wet scrubbers is well known and has been studied since the mid 1970s (McCain and others, 1975; Ensor and others, 1975). As a result of these challenges, the quantity of total aerosols and sulfate aerosols was measured at the MRY by Markowski and others, 1983. Markowski and others (1983) collected EPA Method 17 particulate samples and size-segregated the particles using an impactor (aerodynamically separates particles and allows for the characterization of each fraction). The results of the EPA method 17 sampling (mass concentration) conducted over a four-day period are illustrated in Figure C-18 for the inlet and outlet of the scrubber. At the inlet, aerosol mass concentrations ranged from a high of more than 10,000 $\mu g/m^3$ to a low of 4,000 $\mu g/m^3$. Significant levels were also found at the scrubber outlet, ranging from 8,800 to 2,500 $\mu g/m^3$. The removal efficiency varied from -25 to 66%.

Markowski and other (1983) offered no explanation of the differences in the levels of aerosols measured in the flue gas and removal efficiency. They did not consider that the ash content of the coal varied significantly during the testing. Results of testing at MRY have shown significant differences in the quantity vaporized for coals that have different ash contents (see Figure C-3). The variations in ash content shown in Figure C-18 reflect changing coal characteristics that resulted in differences in aerosol mass concentration.

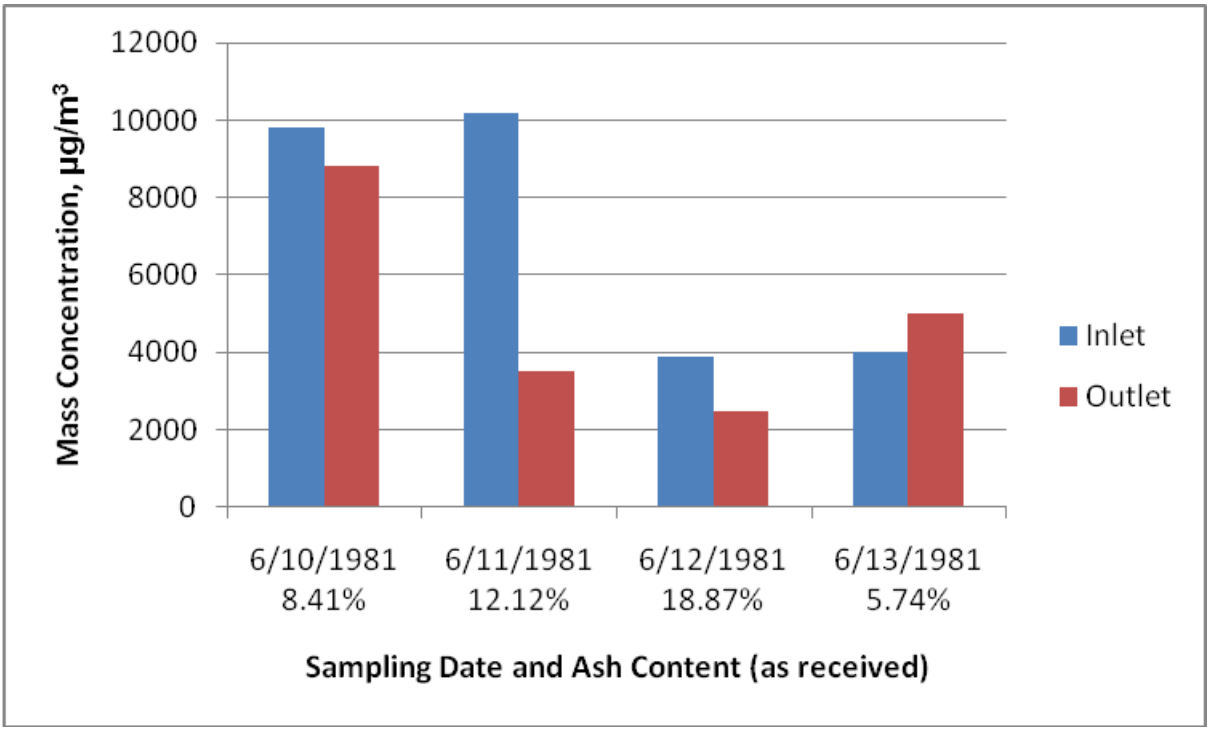


Figure C-18. Mass Concentration of Aerosol Collected at MRY Unit 2 at the Scrubber Inlet and Outlet (Markowski and others, 1983).

The results of the measurements of aerosol capture are illustrated in Figure C-19. The results show that aerosols less than one micrometer in diameter are not effectively captured in the wet FGD at the MRY facility. The graph also indicates the penetration of the particles through the FGD as a function of particle size. The penetration is the outlet size distribution divided by the inlet size distribution. (*Note: Penetration = 1- efficiency*). Markowski and others (1983) showed that the "metallic" sulfate aerosols (sodium sulfate) penetrated the FGD much more effectively than the larger particulate materials.

The mass of each of the impactor size fractions for the aerosols collected at the inlet and the outlet of the wet FGD upstream and downstream of the scrubber are illustrated in Figure C-20 and 21 with the results tabulated in Table C-5. The total mass distributions are summarized in Figure C-20 and the sulfate mass distribution is illustrated in Figure C-20.

Based on the impactor data the total mass of particulate that penetrates the scrubber is 5990 µg/m^3 (Markowski and others, 1983). These ash materials consist of a combination of sulfates and oxides of sodium, calcium, and sulfur. Much of the aerosol is present in the >14 µm size fraction. There are also significant mass in the less than 1 µm size fraction. All of these particles have the potential to penetrate the pores of the catalyst. In addition, there is a significant mass in the <0.26 µm fraction. This fraction represents the ultrafine component that has been implicated as the most significant contributor to catalyst poisoning (Kling and others, 2007).

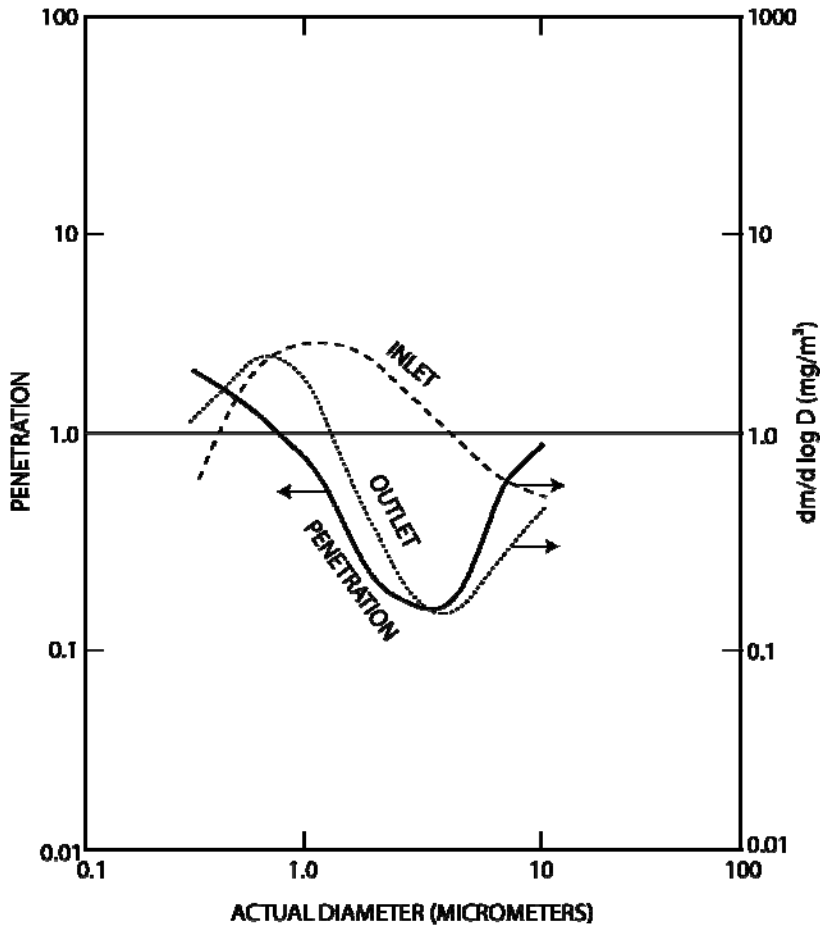


Figure C-19. Penetration through the wet scrubber (Markowski and others, 1983).

Table C-5. Size-segregated total and sulfate particulate collected upstream and downstream of the MRY FGD. (Markowski and others, 1983).

	Inlet	Outlet	Inlet	Outlet
Size, µm	Total, µg/m^3	Total, µg/m^3	Sulfate, µg/m^3	Sulfate, µg/m^3
<0.26	1910	769	436	602
0.26-0.52	401	640	164	274
0.52-1.1	883	1410	293	459
1.1-2.5	1020	265	291	69.2
2.5-6.7	337	154	173	94
6.7-14	300	367	100	103
>14	700	2390	439	46.2
Total	5550	5990	1896	1650
>1.1	2357	3176	1003	312.4
<1.1	3194	2819	893	1335
Percent				
>1.1	42.5 %	53.0 %	52.9 %	18.9 %
<1.1	57.5 %	47.1 %	47.1 %	80.9 %

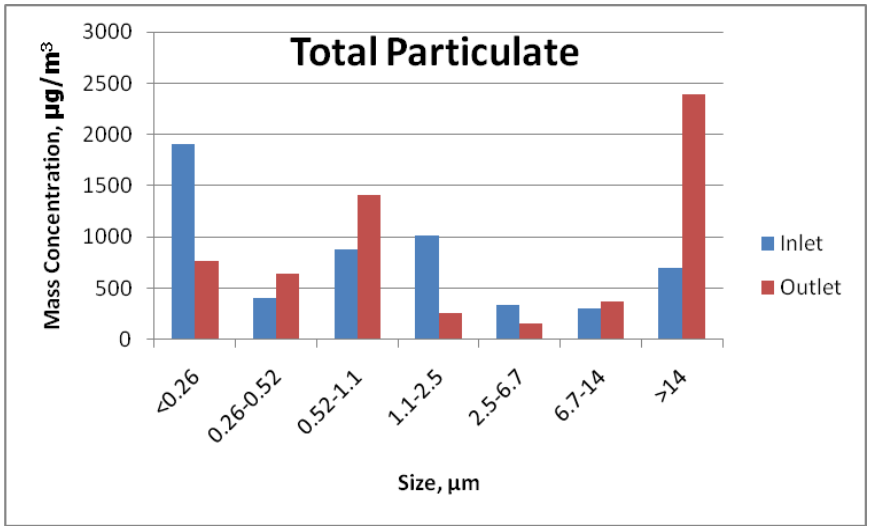


Figure C-20. Total particulate removal across scrubber at MRY.

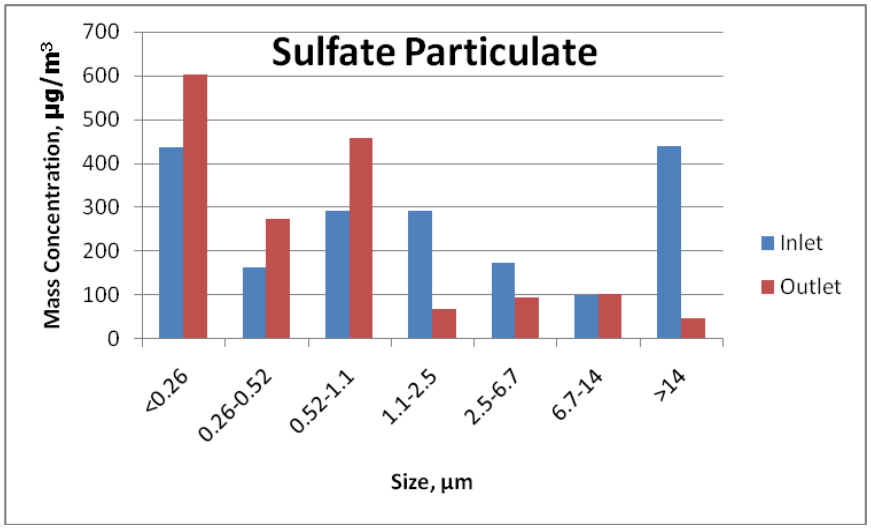


Figure C-21. Sulfate particulate removal across scrubber at MRY.

Estimation of Alkali Aerosol Loading and Catalyst Deactivation

The following data was used to estimate alkali aerosol loading and catalyst deactivation. The particle loading was based on the results of testing conducted by Markowski and others (1983) where they determined the mass loadings of aerosols at the inlet and outlet of the wet FGD at MRY Unit 2. The key data utilized is illustrated in Figure C-22 to estimate the loadings. The data provided shows a range of mass concentrations up to 8,800 µg/m^3 at the outlet of the scrubber. Based on results in mass size distribution of the aerosol 47 to 80% of the aerosols that pass through the scrubber is less than 1.1 µm. Much of this material is in the ultrafine fraction.

These materials have the potential to penetrate into the catalyst causing plugging and can react with active components in the catalyst. There are numerous publications supporting these mechanisms. Kling and others(2007) found that the rate of catalyst deactivation was related to the accumulation of sodium and potassium on the catalyst as shown in Figure C-23 and 24. The

work by Kling and others (2007) is consistent with the work conducted by Khodayari (2001) illustrated in Figure C-25 where it was shown that the deactivation rate is more significant for PC fired systems as compared to fluidized beds. The work based on Kling and others when applied to PC- and cyclone-fired systems will likely underestimate the degree of deactivation because of the firing methods.

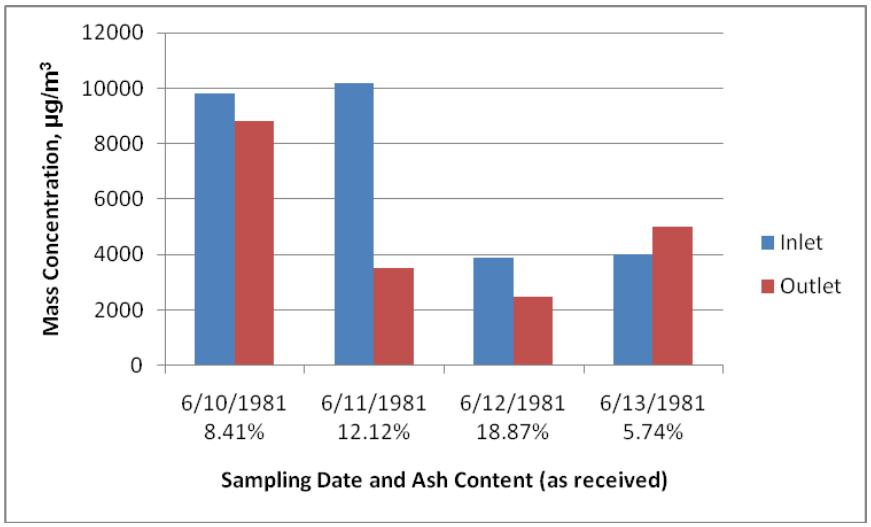


Figure C-22. Mass Concentration of particulate collected at MRY using EPA Method 17 (Markowski and others, 1983).

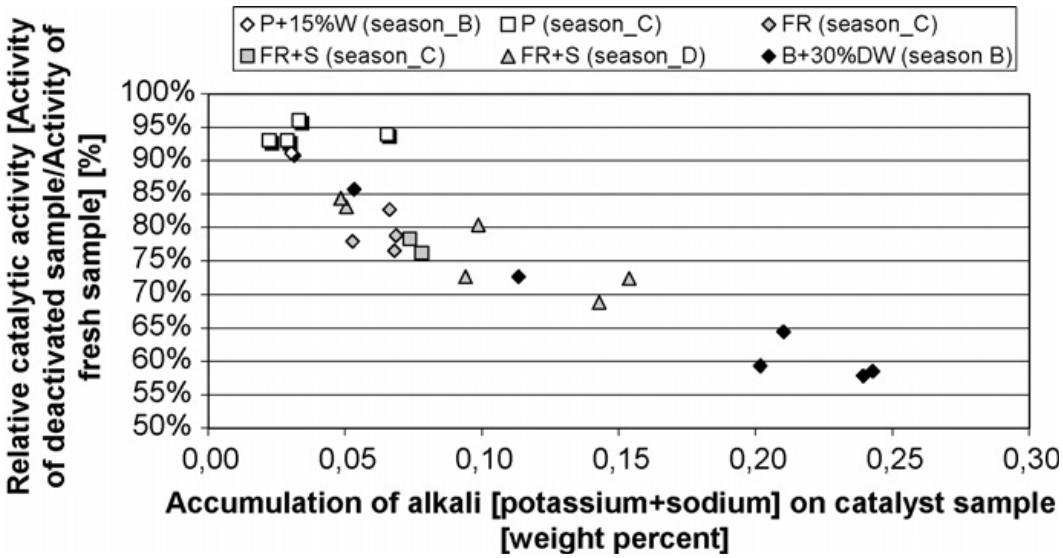


Figure C-23. Catalyst deactivation compared to accumulation of potassium and sodium on the catalyst surface (Kling and others, 2007).

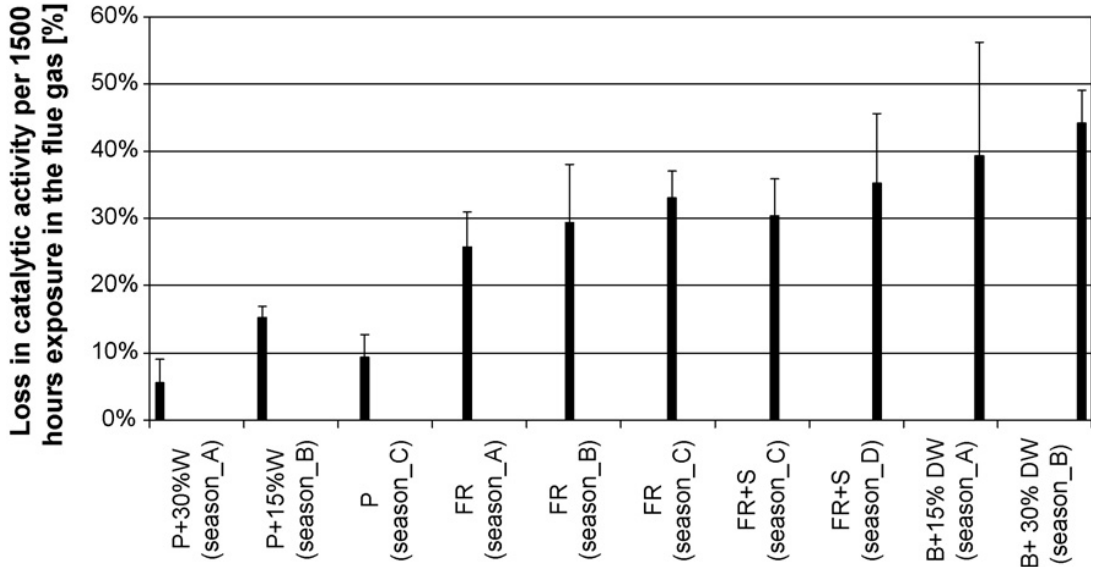


Figure C-24. Loss in catalyst activity when exposed to flue gases containing vaporized Na and K when combusting biomass in a fluidized bed combustion system (Kling and others, 2007).

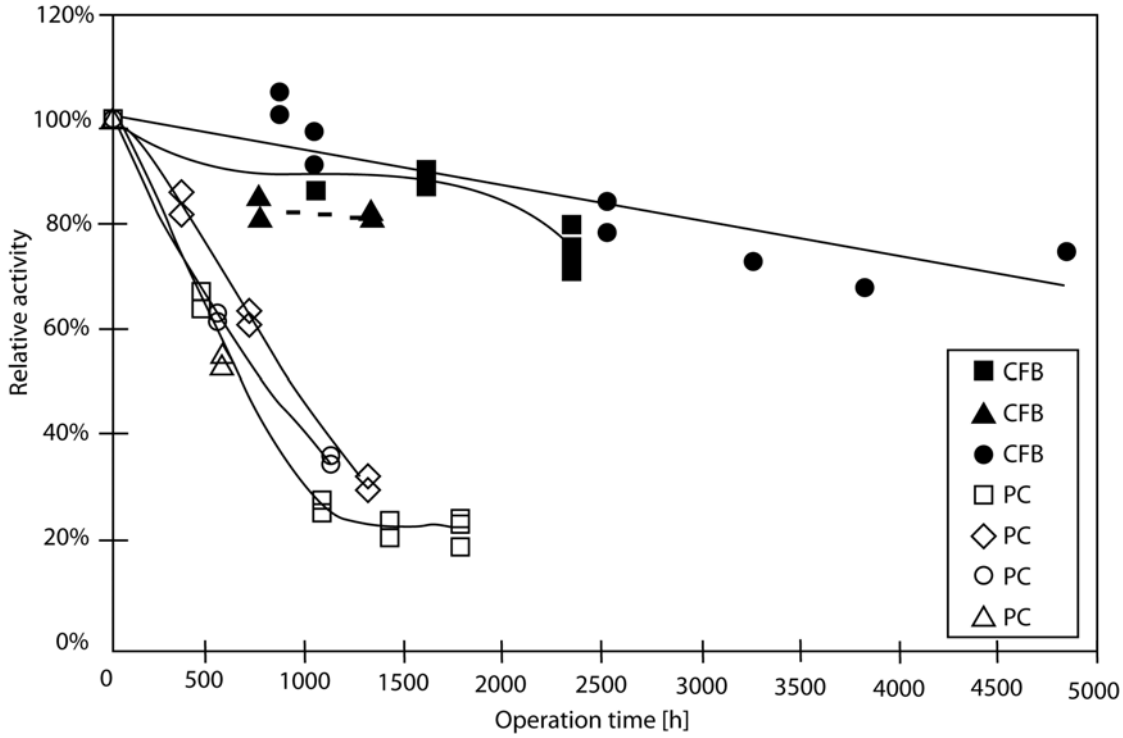


Figure C-25. Comparison of poisoning of catalysts in a CFB boiler firing forest residues, and in a PC firing pulverized wood (Khodayari, 2001).

REFERENCES

Benson, S.A.; Laumb, J.D.; Crocker, C.R.; Pavlish, J.H., SCR Catalyst Performance in Flue Gases Derived from Subbituminous and Lignite Coals. *Fuel Process*. *Technol*. **2005**, *86*, 577–613.

Benson, S.A.; Holm, P.L. Comparison of Inorganic Constituents in Three Low-Rank Coals. *Ind. Eng. Chem. Prod. Res. Dev.* **1985**, *24*, 145.

Benson, S.A.; Rindt, D.K.; Montgomery, G.G.; Sears, D.R. Microanalytical Characterization of a North Dakota Fly Ash. *Industrial and Engineering Product Research and Development* **1984**, *23*, 252.

Benson, S.A.; Jones, M.L.; Harb, J.N. Ash Formation and Deposition. In *Fundamentals of Coal Combustion for Clean and Efficient Use*; Smoot, D.L., Ed.; Coal Science and Technology 20 Series; Elsevier: Amsterdam, 1993; Chapter 4, pp 299–373.

Buecker, Brad, How Pollutants are Formed During Combustion (And How It Affects Control Methods), Power Engineering magazine, April 2008, accessed on-line at: http://pepei.pennnet.com/display_article/326581/6/ARTCL/none/none/1/How-Pollutants-AreFormed-During-Combustion-(And-How-It-Affects-Control-Methods)/

Chen, J.P.; Buzanowski, M.A.; Yang, R.T.; Cichanowicz, J.E., Deactivation of the Vanadia Catalyst in the Selective Catalytic Reduction Process. J. Air Waste Manage. Assoc. 1990, 40, 1403-1409.

Ensor, D.S., Jackson, B.S., Calvert, S., Lake, C., Walton, D.V., Nilan, R.E., Campbell, K.S., Cahill, T.A., Flocchini, R/G., EPA Report No. 600/12-75-074, Washington, D.C., 1975

Fisia Babcock SCR Installation Reference List, accessed on 11/3/2008 at http://www2.fisia-babcock.eu/references.php?list=5.

Guo, X., Poisoning and Sulfation on Vandia SCR Catalyst. Doctor of Philosophy Dissertation, Department of Chemical Engineering, Brigham Young University, August 2006.

Hurley, J.P.; Katrinak, K.A., Determination of Ash Formation and Deposition Mechanisms at Minnesota Power Clay Boswell Station; DOE/MC/10637-3365, July 1992.

ICAC Institute of Clean Air Companies, Particulate controls, http://www.icac.com/i4a/pages/index.cfm?pageid=3398

IEA Coal Research book “NOx control installations on coal-fired plants” (Rudow Unit 2 TESCR startup listed as 1990).

Khodayari, R., Andersson, C., Odenbrand, C.U.I., Andersson, L.H., in: Proceedings of the Fifth European Conference on Industrial Furnace and Boilers, vol. II, 11–14 April 2000, Espinho, Porto, Portugal, 2000.

Khodayari, R., Selective Catalytic Reduction of NOx: Deactivation and Regeneration Studies and Kinetic Modeling of Deactivation, Ph.D. Thesis, 2001, Dept. of Chemical Engineering II, Lund, Sweden.

Kling, A.; Andersson, C.; Myringer, A.; Eskilsson, D.; Jaras, S.G., Alkali Deactivation of High-Dust SCR Catalysts Used for NOx Reduction Exposed to Flue Gas from 100-MW-Scale Biofuel and Peat Fired Boilers: Influence of Flue Gas Composition. Applied Catalysis B: Environmental 2007, 69, 240-251.

Lind, T., Hokkinen, J., and Jokiniemi, J.K., Saarikoski,S., and Hillamo, R., Electrostatic Precipitator Collection efficiency and Trace Element Emissions from Co-Combustion of Biomass and Recovered Fuel in Fluidized-bed Combustion, Environmental Science and Technology, 2003, 37, 2842-2846.

Lighty, J.S., Varanth, J.M., and Sarofim, A.F., Combustion Aerosols: Factors Governing Their Size Composition and Implications to Human Health, J. Air & Waste Manage Assoc, 50:1565-1618, 2000.

Markowski, G.R., Downs, J.L., and Woffinden, G.J., Sulfate Aerosols from Western Low-Rank Coal-Fired Boilers with FGD: Summary of Tests at Coal Creek, Clay Boswell, Milton R. Young, and San Miguel Stations, DOE/FC/10182-t15 (DE83014539), May 1983.

McCain, J.D., Gooch, J.P., Smithw.B., J. Air Pollut. Control Assoc., 1975, 25, 117

Miles, T.R.; Miles, T.R.; Baxter, L.L.; Bryers, R.W.; Jenkins, B.M.; Oden, L.L., Alkali Deposits Found in Biomass Power Plants. A Preliminary Investigation of Their Extent and Nature; Summary Report for National Renewable Energy Laboratory Subcontract No. TZ-2-1-1226-1, April 1995.

Nobrega, S.W., Falaguasta, M.C.R., and Coury, J.R., A Study of a Wire-Plate Electrostatic Precipitator Operating in the Removal of Poly dispersed Particles, Brazilian Journal of Chemical Engineering, Vol 21, No. 02, pp 273-284, April-June 2004.

Noppenau, Henrik, Cleaner Fossil Fuels for Sustainable Development Co-firing Coal and Biomass, Accessed 10/28/2008 at http://www.usea.org/CFFS/CFFSNeptun/Co-firing%20-(WEC-CFFS)%20Neptun%20June%2013%202006.pdf

Ohlström, Mikeal, Jokiniemi, Jorma, Hokkinen, Jouni, Makkonen, Pasi, and Tissari, Jarkko, Combating Particulate Emissions in Energy Generation and Industry, Tekes, VTT Technical Research Centre of Finland, 2006.

Power Station Emissions Handbook, Cooperative Research Centre for Coal in Sustainable Development, http://www.ddsd.biz/PSE_Handbook/5/6/5/index.cfm accessed 11/24/2008.

Senior, C.L., Panagiotou, T, Sarofim, A. F., and Helble, J.J., Formation of Ultra-Fine Particulate Matter from Pulverized Coal Combustion, Preprints Division of Fuel Chemistry, American Chemical Society, 45(1), 2000.

Strege, J.R.; Zygarlicke, C.J.; Folkedahl, B.C.; SCR Deactivation in a Full-Scale Cofired Utility Boiler. Fuel 2008, 87 (7), 1341-1347.

Tolbert, S.G.; Benson, S.A. JV Task 117 - Impact of Lignite Properties on Powerspan's NOx Oxidation System; Final Report (May 1 - Dec 31, 2007) for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-98FT40321, Powerspan, Montana-Dakota Utilities Co., Minnesota Power, Basin Electric Power Cooperative, North Dakota Industrial Commission, and Minnkota Power Cooperative, Inc.; EERC Publication 2008-EERC-03-09; Energy & Environmental Research Center: Grand Forks, ND, April 2008.
White, Nathan, Washing Your Own Catalyst, NOx Round Table 2007, Cincinnati, Ohio, February 5-6, 2007.

Woodward, K. , Stationary Source Control Techniques Document for Fine Particulate Matter, EPA-452/R-97-001, October 1998. (http://www.epa.gov/ttncatc1/dir1/finepmtech.pdf)

Zheng, Y.; Jensen, A.D.; Johnsson, J.E. Deactivation of V2O5-WO3-TiO2 SCR Catalyst at a Biomass-Fired Combined Heat and Power Plant; Applied Catalysis B: Environmental 2005 60, 253-264.

Zheng, Y.; Jensen, A.D.; Johnsson, J.E.; Thøgersen, J.R. Deactivation of V2O5-WO3-TiO2 SCR Catalyst at Biomass Fired Power Plants: Elucidation of Mechanisms by Lab- and Pilot-Scale Experiments; Applied Catalysis B: Environmental. 2008, 83, 186-194.

Table 4 – MRYS Unit Design and Operating Parameters

Design Unit Operating Characteristics[1]	Unit 1 Design	Unit 2 Design
Boiler Type	Cyclone	Cyclone
Boiler Manufacturer	B&W	B&W
Boiler Design Heat Input Capacity (nameplate), mmBtu/hr	2,510	4,696
Unit Nameplate Generator Output Capacity, MW_g (gross)	257	477
Unit Nominal Full Load (NFL) Output, MW_g (gross)	235	450
Boiler Heat Input for Unit NFL Output, mmBtu/hr	2,508	4,814
Boiler Excess O_2, %, (wet, NFL)	3.17	4.04
Boiler Excess Air, % (NFL)	21.3	28.5
Fly Ash Portion of Total Ash, % (NFL)	45	50
Typical Maximum Continuous Rating (MCR) output, MW_g	253	462
Maximum Unit Output (URGE) Rating, MW_g	278	512
Boiler Firing Conditions for Flue Gas Flow Calculations:		
Boiler Heat Input, mmBtu/hr	2,852	4,740
Coal Higher Heating Value, Btu/lb as-received	6,578	6,578
Coal Flow Rate for heat input, lb/hr	433,500	720,500
Fly Ash Portion of Total Ash, %	50	50
Flue Gas Conditions at the boiler flue gas outlet:		
Boiler Excess O_2, %, (wet)	2.87	4.77
Boiler Excess Air, %	19.0	35.4
Flue Gas Mass Flow Rate, lb/hr	3,811,000	7,117,000
Flue Gas Volumetric Flow Rate, acfm	2,502,000	4,371,000
Flue Gas Temperature, degrees F	910	818
Flue Gas Pressure, in. w.g.	-11.5	-13.5
Boiler Outlet Maximum SO_2, lb/mmBtu	3.0[2]	3.0[2]
Boiler Outlet Maximum SO_2, lb/hr	8,970	15,474
Average Boiler Heat Input for SO_2, mmBtu/hr	2,990	5,158
Expected Boiler Outlet Maximum 30-day average SO_3, lb/hr	135[3]	236[3]

(1) – Boiler unit operating parameters are provided for more than one load or output condition.

(2) – Boiler Outlet Maximum SO_2 lb/mmBtu is based on 1.0% S and 6,578 Btu/lb higher heating value content in the as-received lignite coal.

(3) – Boiler Outlet Maximum SO_3 lb/hr is based on the assumed conversion of 1.5% of the boiler outlet SO_2 to SO_3 upstream of any flue gas treatment. This conversion percentage has not been confirmed by actual boiler outlet flue gas test measurements. The SO_2 lb/mmBtu and lb/hr values have not been reduced by this assumed SO_3 conversion.

Table C2 summarizes the average, maximum and minimum values for the entire as-fired coal database. The ranges on the various components can be very large. For example, the ash content ranges from 5 to 25%. Sodium oxide content ranges from 0.6 to 13% of the ash.

Table C2. Average, maximum, and minimum of basic coal analysis for all the coals in the as-fired database - Center Lignite Coal

ID NUMBER	Moisture	Ash	Sulfur	Btu	Volatile Matter	Fixed Carbon	Aluminum Oxide	Barium Oxide	Calcium Oxide	Iron Oxide	Magnesium Oxide	Manganese Dioxide	Phosphorus Pentoxide	Potassium Oxide	Silicon Dioxide	Sodium Oxide	Strontium Oxide	SO3	Titanium Dioxide	Basic total	Acid Total	Base/Acid Ratio
							Al_2O_3	Ba	CaO	Fe_2O_3	MgO	Mn	P_2O_5	K_2O	SiO_2	Na_2O	Sr	SO_3	TiO_2			
Average	**37.1**	**9.64**	**1.0**	**6578.1**	**25.3**	**28.0**	**11.7**	**0.5**	**13.2**	**8.9**	**4.0**	**0.1**	**0.1**	**1.3**	**36.0**	**4.4**	**0.4**	**18.4**	**0.5**			**0.7**
Max	**39.4**	**25.5**	**2.6**	**7101.0**	**31.1**	**31.2**	**15.6**	**1.2**	**24.0**	**24.7**	**7.1**	**0.3**	**1.0**	**2.3**	**56.0**	**13.0**	**37.0**	**34.5**	**0.7**			**2.5**
Min	**33.6**	**5.0**	**0.5**	**5852.0**	**22.3**	**13.7**	**6.3**	**0.2**	**6.8**	**5.4**	**2.3**	**0.0**	**0.0**	**0.2**	**12.3**	**0.6**	**0.2**	**8.1**	**0.2**			**0.3**
90th Perc.	**38.10**	**12.51**	**1.29**	**6820**	**26.5**	**29.9**	**14.2**	**0.8**	**19.9**	**12.2**	**5.7**	**0.1**	**0.4**	**1.9**	**46.0**	**8.71**	**0.6**	**26.3**	**0.6**			**1.26**
10th Perc.	**35.95**	**7.06**	**0.72**	**6359**	**24.3**	**26.1**	**9.6**	**0.4**	**9.7**	**7.1**	**3.0**	**0.1**	**0.0**	**0.6**	**22.7**	**1.99**	**0.2**	**14.4**	**0.4**			**0.44**
45th Perc.	**37.17**	**9.33**	**0.90**	**6552**	**25.2**	**28.0**	**11.6**	**0.5**	**12.2**	**8.3**	**3.8**	**0.1**	**0.1**	**1.4**	**37.0**	**4.09**	**0.3**	**17.3**	**0.5**			**0.592**
55th Perc.	**37.37**	**9.75**	**0.94**	**6592**	**25.4**	**28.3**	**12.0**	**0.5**	**12.7**	**8.7**	**4.0**	**0.1**	**0.1**	**1.4**	**38.4**	**4.61**	**0.4**	**18.0**	**0.5**			**0.637**

1. Ash weight percent was determined on an “as-fired” lignite coal basis.
2. BTU (higher heating value) content expressed on an “as-fired” lignite coal basis.
3. Constituent weight percent of the ash, elemental weight percent expressed as equivalent oxide.
4. B/A is the base to acid weight ratio of the ash constituents ($B/A=[Na_2O+MgO+CaO+ K_2O+FeO]/[SiO_2+Al_2O_3+TiO_2]$).

MDJ 3019-1

UTILITY BOILER PERFORMANCE SUMMARY

THIS SUMMARY SHEET IS THE PROPERTY OF THE BABCOCK & WILCOX CO. AND IS LOANED UPON THE UNDERSTANDING THAT IT IS NOT TO BE COPIED, IN WHOLE OR IN PART, OR USED FOR FURNISHING INFORMATION TO OTHERS, OR FOR ANY OTHER PURPOSE DETRIMENTAL TO THE INTERESTS OF THE BABCOCK & WILCOX CO. AND IS TO BE RETURNED UPON REQUEST.

A. FUEL AS FIRED

SAMPLES			
ANALYSES	SPECIFIED		
COAL — KIND			-
COAL — ASTM CLASS			IV
COAL — ASTM GROUP			I
COAL — SOURCE MINE			
COAL — SOURCE SEAM			
COAL — SOURCE DISTRICT			
COAL — SOURCE COUNTY			OLIVER
COAL — SOURCE STATE			N.D.
COAL — SIZE			
COAL — GRINDABILITY		22	30
COAL — SURFACE MOISTURE, %		3.0-5.0	5.0
ASH SOFT. TEMP., F (REDUCING)			
PROX. ANAL., % — MOISTURE, TOTAL		276-403	36.0
PROX. ANAL., % — VOLATILE MATTER		270-320	29.1
PROX. ANAL., % — FIXED CARBON		270-320	29.1
PROX. ANAL., % — ASH		3.9-8.3	5.8
PROX. ANAL., % — TOTAL			100.0
ULTIMATE ANALYSIS — FUEL		LIGNITE	LIGNITE
ULTIMATE ANALYSIS — % BY			WT.
ULTIMATE ANALYSIS — ASH		3.9-8.3	5.80
ULTIMATE ANALYSIS — S			0.74
ULTIMATE ANALYSIS — H_2		2.9-3.5	3.00
ULTIMATE ANALYSIS — C		38.9-46.1	40.40
ULTIMATE ANALYSIS — CH_4			
ULTIMATE ANALYSIS — C_2H_6			
ULTIMATE ANALYSIS — C_3H_8			
ULTIMATE ANALYSIS — C_4H_{10}			
ULTIMATE ANALYSIS — C_5H_{12}			
ULTIMATE ANALYSIS — C_6H_{14}			
ULTIMATE ANALYSIS — CO		.001-.001	0.01
ULTIMATE ANALYSIS — CO_2			
ULTIMATE ANALYSIS — SO_2			
ULTIMATE ANALYSIS — H_2O		275-40.3	36.00
ULTIMATE ANALYSIS — N_2		.4-.74	0.65
ULTIMATE ANALYSIS — O_2			13.40
ULTIMATE ANALYSIS — TOTAL			100.00
HHV/LB		6250-7830	6900
BTU/CU FT AT 60F 30 IN. HG			

B. PREDICTED PERFORMANCE

STEAM LEAVING SH, M LB/HR	990	1650	1714
STEAM LEAVING RH1, M LB/HR	876	1460	1534
STEAM LEAVING RH2, M LB/HR			
TYPE OF FUEL	LIGNITE		
LOAD DURATION	CONTINUOUS		
EXCESS AIR ENTERING AIRHEATER	31	28	28
NO. OF BURNERS IN OPERATION	7	7	7
FUEL INPUT, MMB/HR	1565	2422	2510
HEAT AVAIL. MMB/HR (FUEL & HEATED AIR)	1620	2559	2649
QUANTITY, LB/HR — FUEL (MCFH-NAT. GAS)	227	352	364
QUANTITY, LB/HR — FLUE GAS ENTERING AIR HEATER	2250	2817	2919
QUANTITY, LB/HR — AIR LEAVING SEC. AH & PRI. AH	1520	2312	2396
QUANTITY, LB/HR — AIR HEATER LEAKAGE			
PRESSURE, PSIG — STEAM AT SH OUTLET	1875	1875	1970
PRESSURE, PSIG — STEAM AT RH1 INLET	258	457	480
PRESSURE, PSIG — STEAM AT RH2 INLET			
PRESSURE DROP — REHEATER 1	15	25	26
PRESSURE DROP — REHEATER 2			
PRESSURE DROP — ECONOMIZER	11	30	33
PRESSURE DROP — DRUM TO SH OUTLET	45	125	135
TEMPERATURE, F — STEAM — LEAVING SUPERHEATER	1010	1010	1010
TEMPERATURE, F — STEAM — LEAVING REHEATER 1	970	1010	1010
TEMPERATURE, F — STEAM — ENTERING REHEATER 1	590	664	663
TEMPERATURE, F — STEAM — LEAVING REHEATER 2			
TEMPERATURE, F — STEAM — ENTERING REHEATER 2			
TEMPERATURE, F — FLUE GAS — LEAVING PRI. SH	810	890	900
TEMPERATURE, F — FLUE GAS — LEAVING AH (EXCL. LKG)	370	325	330
TEMPERATURE, F — FLUE GAS — LEAVING AH (INCL. LKG)			
TEMPERATURE, F — WATER ENTERING ECONOMIZER	408	461	466
TEMPERATURE, F — AIR — ENTERING AIR HEATER	100	100	100
TEMPERATURE, F — AIR — LEAVING AIR HEATER	735	768	777
RESISTANCE, IN. OF WATER — GAS — FURNACE & CONVECTION BANKS	2.4	3.7	4.0
RESISTANCE, IN. OF WATER — GAS — FLUES TO STACK	1.3	1.9	2.0
RESISTANCE, IN. OF WATER — GAS — AIR HEATER & ECON.	4.9	7.6	8.1
RESISTANCE, IN. OF WATER — GAS — DUST COLLECTOR	1.7	2.7	3.0
RESISTANCE, IN. OF WATER — GAS — TOTAL DRAFT LOSS	10.3	15.9	17.1
RESISTANCE, IN. OF WATER — AIR — FUEL BURNERS & WINDBOX	36.5	36.5	36.5
RESISTANCE, IN. OF WATER — AIR — DUCTS & FLOW METER	2.1	3.2	3.5
RESISTANCE, IN. OF WATER — AIR — AIR HEATER	1.5	2.4	2.6
RESISTANCE, IN. OF WATER — AIR — STEAM COIL AH	0.3	0.5	0.5
TOT. AIR RESISTANCE	40.4	42.6	43.1
HEAT LOSS, % — DRY GAS	6.70	5.46	5.58
HEAT LOSS, % — H_2 & H_2O IN FUEL	10.51	10.38	10.40
HEAT LOSS, % — MOISTURE IN AIR	0.17	0.14	0.14
HEAT LOSS, % — UNBURNED COMBUSTIBLE	0.10	0.10	0.10
HEAT LOSS, % — RADIATION	0.32	0.19	0.18
HEAT LOSS, % — UNACC. FOR & MFRS. MARGIN	1.10	1.10	1.10
HEAT LOSS, % — SLAG TANK	0.40	0.40	0.40
HEAT LOSS, % — TOTAL HEAT LOSS	19.30	17.77	17.90
EFFICIENCY OF UNIT, %	80.70	82.23	82.10
PULVERIZERS — NO. IN USE PER BOILER			
PULVERIZERS — TOTAL POWER, KWHR/TON MOTOR OUTPUT			
PULVERIZERS — % THRU 200 U.S.S. SIEVE			

PREDICTED PERFORMANCE IS BASED ON COMBUSTION AIR ENTERING UNIT WITH 0.013 LB MOISTURE/LB DRY AIR, ON 27.72 IN. HG. BAROMETRIC PRESSURE, ON CONDITIONS & EQUIPMENT GIVEN ON THIS SUMMARY SHEET & ON ARRANGEMENT SHOWN ON DRAWING 11X0

C. EQUIPMENT PER UNIT

TYPE	RADIANT
SIZE	RBC 57/CY.
	DESIGN PRESSURE 2325 PSIG
FURNACE PRESSURE PART. HEATING SURFACE, SQ FT — WATER COOLED SCREEN (CIRCUMFERENTIAL)	
WATER COOLED (PROJECTED)	33760
SUPERHEATER (CIRCUMFERENTIAL)	9229
SUPERHEATER (PROJECTED)	1200
TOTAL FURNACE HEATING SURFACE	44189
CONVECTION — SATURATED (CIRCUMFERENTIAL)	5910
CONVECTION — SUPERHEATER (CIRCUMFERENTIAL)	91607
CONVECTION — REHEATER 1 (CIRCUMFERENTIAL)	36947
CONVECTION — REHEATER 2 (CIRCUMFERENTIAL)	
CONVECTION — ECONOMIZER	44900
CONVECTION — TOTAL CONVECTION HEATING SURFACE	179164
TOTAL FURN. & CONV. PRESSURE PART. HTG. SURF.	223353
FLAT PROJECTED FURNACE HEATING SURFACE	
TO FACE OF PLATENS	37925
TO FACE OF CONVECTION SURFACE	
FURNACE VOLUME, CU FT	148800
AIR HEATER — TYPE TUBULAR	NO. 1
AIR HEATER — TOTAL HEATING SURFACE, SQ FT	742,000
FUEL BURNER — TYPE CYCLONE	
FUEL BURNER — NO. 7-10 FT. DIA.	
PULVERIZER — TYPE / SIZE / NO.	
PULVERIZER — CAPACITY OF / PULV. IS M LB STEAM/HR BASED ON GRIND	
PULVERIZER — BTU COAL AT % THRU 200 U.S.S. SIEVE	
PULVERIZER — FOR M LB COAL/PULV.-HR AT % THRU 200 U.S.S. SIEVE, MIN. GRIND	
PULVERIZER — IS , MAXIMUM SURFACE MOISTURE IS % REQUIRING F AIR	
STEAM TEMP. CONTROL	STEAM TEMPERATURE CONTROLLED BY GAS RECIRCULATION
UNIT CONSTRUCTION FEATURES	BALANCED DRAFT
	SEMI-OUTDOOR
	MEMBRANE WALL
	SOLIDS IN STEAM 1 PPM

REVISIONS	DESCRIPTION	BY	DATE

BY [illegible] APPD. DATE APRIL 1967

THE BABCOCK & WILCOX COMPANY

P1-3941-11X0-1S0

1

MINNESOTA POWER COOPERATIVE
SANDERSON AND PORTER, INC.
ENGINEERS

235MWe UNIT 1 RB-457

TO:9P18163333690 P:5/5
FROM:MINNKOTA POWER 7017947258
7-2002 13:44
THIS SHEET IS THE PROPERTY OF THE BABCOCK & WILCOX COMPANY AND IS LOANED UPON CONDITION THAT IT IS NOT TO BE COPIED, IN WHOLE OR IN PART OR USED FOR FURNISHING INFORMATION TO OTHERS, OR FOR ANY OTHER PURPOSE DETRIMENTAL TO THE INTERESTS OF THE BABCOCK & WILCOX COMPANY AND IS TO BE RETURNED UPON REQUEST.

A FUEL AS FIRED

SAMPLES

ANALYSES CUSTOMER SPECIFICATIONS

		DESIGN	PERF.
COAL SOURCE	KIND	LIGNITE	LIGNITE
	CLASS		
	GROUP		
	MINE		
	SEAM		
	DISTRICT		
	COUNTY		
	STATE		OLIVER N. DAK.
SIZE			1¼ - 1½
GRINDABILITY		20 MIN	25
SURFACE MOISTURE, %	H=½W		
ASH SOFT. TEMP., F (REDUCING)		2235-2500	2410
PROX. ANAL., %	MOISTURE, TOTAL	38	38.4
	VOLATILE MATTER		25.0
	FIXED CARBON	1	25.0
	ASH	13	11.6
	TOTAL		100.0
ULTIMATE ANALYSIS	FUEL		LIGNITE
	% BY		WT.
	ASH		11.60
	S		0.63
	H_2		2.60
	C		34.70
	CH_4		
	C_2H_4		
	C_2H_6		
	C_3H_8		
	C_4H_{10}		
	C_5H_{12}		
	C_6H_{14}		
	CO		0.61
	CO_2		
	SO_2		
	H_2O		38.40
	N_2		0.56
	O_2		11.50
	TOTAL		100.00
	BTU/LB	6000	6250
	BTU/CU FT AT 60F 30 IN.HG		

* EXCL. STATIC HEAD AND FEED STOP AND CHECK VALVE.

** INPUT & ALL GENERAL PERFORMANCE INCLUDES ALLOWANCE FOR AVERAGE SOOT BLOWER STEAM CONSUMPTION RATE (40,000 LB/HR).

UTILITY BOILER PERFORMANCE SUMMARY

BY VFH APPD. RTP DATE 3-27-73

THE BABCOCK & WILCOX COMPANY

PS-2783-1Y0-1S1

B PREDICTED PERFORMANCE

STEAM LEAVING SH, M LB/HR		1830	2560	3050	3200
STEAM LEAVING RH1, M LB/HR		1510	2110	2513	2729.6
BLOWDOWN, M LB/HR		18.5	25.9	30.8	32.1
TYPE OF FUEL		LIGNITE	LIGNITE	LIGNITE	LIGNITE
LOAD CONDITION		NORMAL	NORMAL	NORMAL	NORMAL MAX
EXCESS AIR LEAVING ECON., %		38	31	28	25
NO. OF BURNERS IN OPERATION		12	12	12	12
FUEL INPUT, MMB/HR **		2849	3883	4505	4675
HEAT AVAIL. MMB/HR (FUEL & HEATED AIR)		2974	4080	4761	4975
QUANTITY, M LB/HR	FUEL	455.8	621.2	720.7	751.4
	FLUE GAS ENTERING AIR HEATER	3410	4439	5050	5264
	AIR TO BURNING EQUIPMENT	2932	3802	4330	4491
	AIR HEATER LEAKAGE				
PRESSURE, PSIG	STEAM AT SH OUTLET	2495	2495	2495	2620
	STEAM AT RH1 INLET	296	407	518	570
	STEAM AT RH2 INLET				
PRESSURE DROP	REHEATER 1	27	23	28	30
	REHEATER 2				
	ECONOMIZER TO DRUM*	17	30	46	50
	DRUM TO SH OUTLET	60	106	155	180
TEMPERATURE, F	STEAM: LEAVING SUPERHEATER	1005	1005	1005	1005
	LEAVING REHEATER 1	980	1005	1005	1005
	ENTERING REHEATER 1	545	582	618	626
	LEAVING REHEATER 2				
	ENTERING REHEATER 2				
	FLUE GAS: LEAVING ECONOMIZER TO AH/TO CR	756/560	818/620	863/685	870/695
	LEAVING AH (EXCL. LKG)	284	310	328	330
	LEAVING AH (INCL. LKG)				
	AIR: WATER ENTERING ECONOMIZER	421	450	473.7	483.7
	ENTERING UNIT	108	100	100	100
	LEAVING AIR HEATER	661	710	745	750
RESISTANCE, IN. OF WATER	GAS: FURNACE & CONVECTION BANKS	3.7	5.1	8.0	8.8
	FLUES TO AH OUTLET	1.6	2.2	2.7	2.8
	AIR HEATER	3.0	5.0	6.5	6.9
	TOT. FURN. TO AH OUTLET	8.3	12.5	17.2	18.5
	AIR: FUEL BURNERS & WINDBOX	43.0	43.0	43.0	44.5
	DUCTS	1.5	2.5	3.2	3.5
	AIR HEATER	2.1	3.6	4.7	5.1
	TOT. FROM FD FAN TO FURN.	46.6	49.1	50.9	53.1
HEAT LOSS, %	DRY GAS	4.79	5.20	5.53	5.58
	H_2 & H_2O IN FUEL	11.08	11.21	11.28	11.30
	MOISTURE IN AIR	0.12	0.13	0.14	0.14
	UNBURNED COMBUSTIBLE	0.10	0.10	0.10	0.10
	RADIATION	0.28	0.21	0.18	0.17
	UNACC. FOR & MFRS. MARGIN & SLAG TANK LOSS	1.83	1.83	1.83	1.83
	TOTAL HEAT LOSS	18.20	18.68	19.06	19.12
EFFICIENCY OF UNIT, %		81.80	81.32	80.94	80.88
PULVERIZER POWER	NO. IN USE PER BOILER				
	TOTAL POWER, KW HR/TON MOTOR OUTPUT				
	% THRU 200 U.S.S. SIEVE				

PREDICTED PERFORMANCE IS BASED ON COMBUSTION AIR ENTERING UNIT WITH 0.013 LB MOISTURE/LB DRY AIR, ON 27.72 IN. HG. BAROMETRIC PRESSURE, OR CONDITIONS & EQUIPMENT GIVEN ON THIS SUMMARY SHEET & ON ARRANGEMENT SHOWN ON DRAWING PS-2783-1Y0

C EQUIPMENT PER UNIT

TYPE RADIANT

SIZE RBC 48/CY

DESIGN PRESSURE 2950 PSIG

PRESSURE PART HEATING SURFACE, SQ FT — FURNACE	WATER COOLED SCREEN (CIRCUMFERENTIAL)	
	WATER COOLED (PROJECTED)	43,260
	SUPERHEATER (CIRCUMFERENTIAL)	
	SUPERHEATER (PROJECTED)	15,360
	TOTAL FURNACE HEATING SURFACE	58,620
CONVECTION	SATURATED (CIRCUMFERENTIAL)	7,120
	SUPERHEATER (CIRCUMFERENTIAL)	127,300
	REHEATER 1 (CIRCUMFERENTIAL)	55,060
	REHEATER 2 (CIRCUMFERENTIAL)	
	ECONOMIZER	161,425
	TOTAL CONVECTION HEATING SURFACE	351,905
TOTAL FURN. & CONV. PRESSURE PART. HTG. SURF.		410,525
FLAT PROJECTED FURNACE HEATING SURFACE	TO FACE OF PLATENS	45,520
	TO FACE OF CONVECTION SURFACE	60,390
FURNACE VOLUME, CU FT		403,500
a/h HEATER	TYPE TUBULAR	NO. 1
	TOTAL HEATING SURFACE, SQ FT	1,336,400
FUEL BURNER	TYPE CYCLONE	
	NO. 12	
PULVERIZER	TYPE SIZE NO.	
	CAPACITY OF PULV. IS M LB STEAM/HR BASED ON GRIND	
	BTU COAL AT % THRU 200 U.S.S. SIEVE	
	FOR M LB COAL/PULV.-HR AT % THRU 200 U.S.S. SIEVE MIN. GRIND	
	IS MAXIMUM SURFACE MOISTURE IS % REQUIRING F AIR	

SOLIDS IN STEAM - 0.1 PPM

STEAM TEMP. CONTROL: GAS RECIRCULATION

UNIT CONSTRUCTION FEATURES: MEMBRANE WALL, BALANCED DRAFT, INDOOR

REVISIONS	NO.	DESCRIPTION	BY	DATE
	0-1	C59	VFH	4/25/73

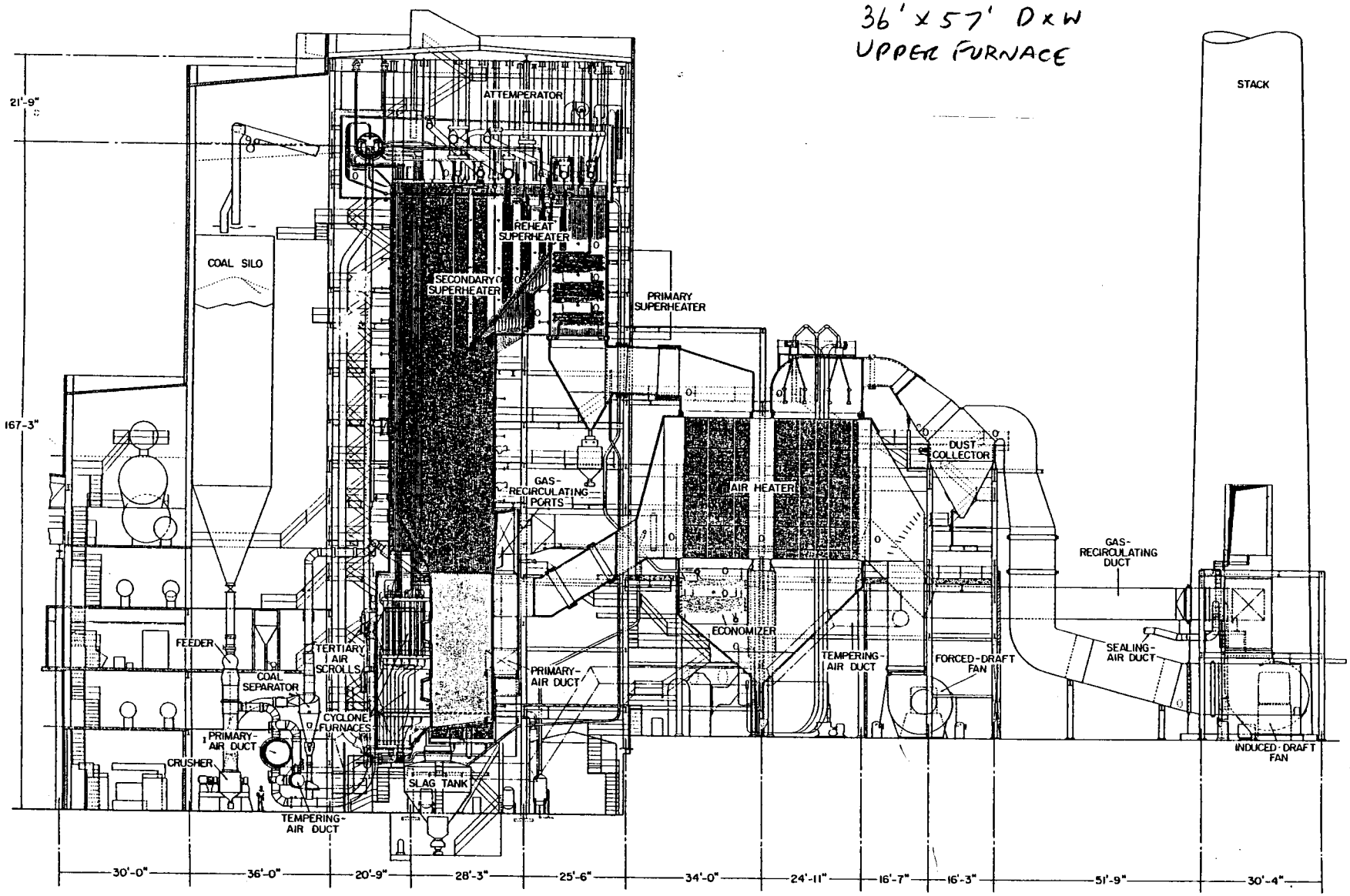
SANDERSON & PORTER, INC.
FOR: SQUARE BUTTE ELECTRIC COOPERATIVE, INC.
MILTON R. YOUNG STATION, NORTH DAKOTA

2

439 MWe RB-525

26' x 57' DxW
LOWER FURNACE

36' x 57' DxW
UPPER FURNACE

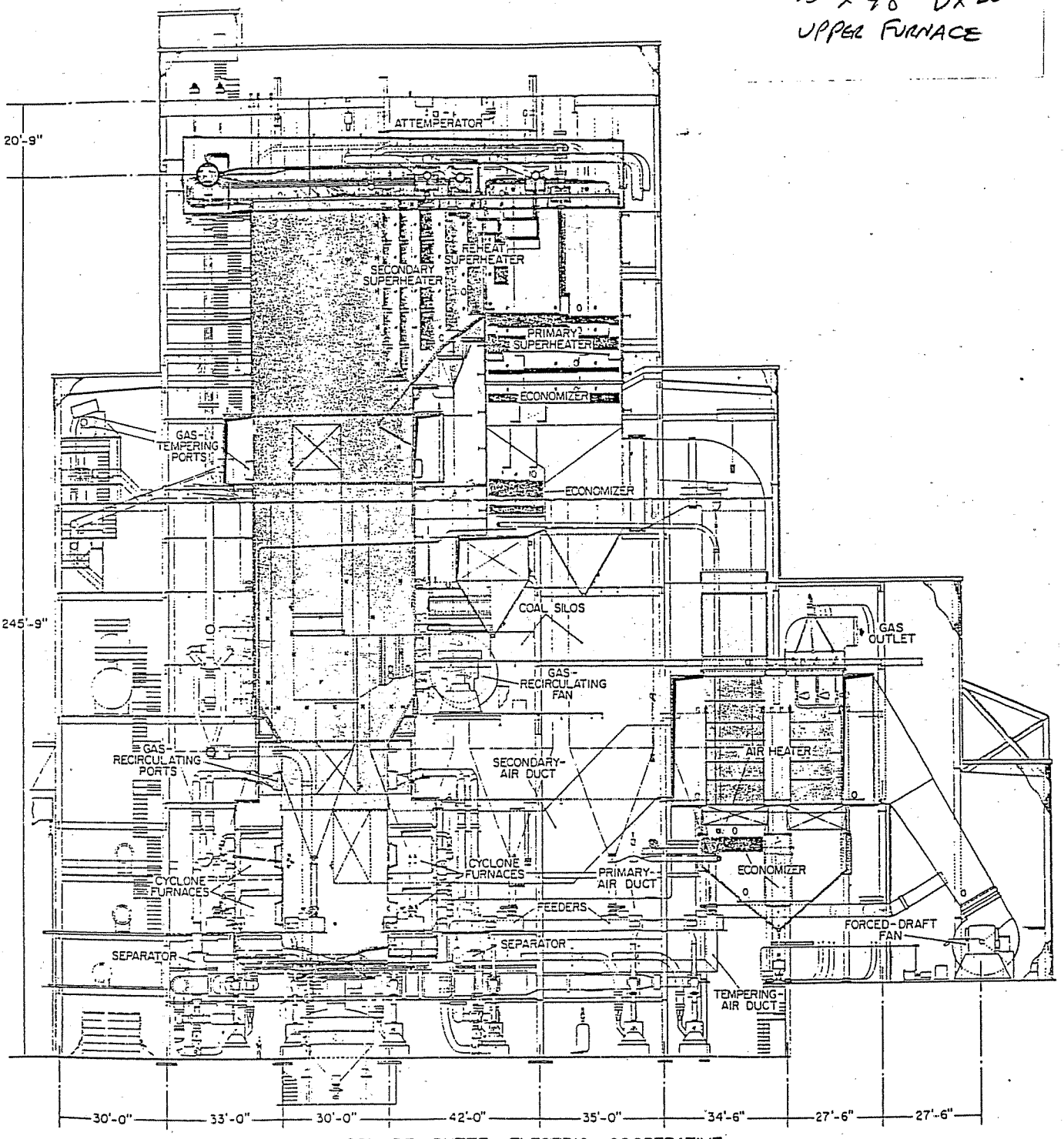


MINNKOTA POWER COOPERATIVE, INC.
CENTER POWER PLANT – UNIT NO. 1
CENTER, NORTH DAKOTA
B & W CONTRACT NO. RB-457

RB-457-500-2N

30' x 48' D x W
LOWER FURNACE

45' x 48' D x W
UPPER FURNACE



SQUARE BUTTE ELECTRIC COOPERATIVE
CENTER POWER PLANT—UNIT NO. 2
CENTER, NORTH DAKOTA
B & W CONTRACT NO. RB-525

Bryant, Ronald

From: Bryant, Ronald

Sent: Wednesday, August 26, 2009 4:30 PM

To: Noel Rosha

Cc: 'lkvernen@minnkota.com'; John Graves; Craig Bleth (cbleth@minnkota.com); Gerry Pfau (gpfau@minnkota.com); Andy Freidt; Weilert, Carl; Blakley, Robert; sbenson@undeerc.org; 51684

Subject: Minnkota SCR Catalyst Recommendations

Attachments: Scope of Services 26Aug09.doc; Report 1084 - Particulate - FINAL 8-20-09.pdf; MRY SCR Vendor Query (4-18-07) - Abbreviated.pdf

Noel

Minnkota Power is requesting recommendations on SCR catalyst design for low-dust and tail-end applications as discussed in our offices on August 11.

Attached are the following documents for your consideration:

1. Scope of Services 26Aug09
2. Report 1084 - Particulate - FINAL 8-20-09
3. MRY SCR Vendor Query (4-18-07) – Abbreviated

The first document summarizes items Minnkota Power is requesting in support of the required BACT.

The second document is flue gas testing data performed at the Milton R. Young Station. This information should be treated confidential.

The third document includes some basic boiler operating parameters and was extracted from the MRY SCR Vendor Query originally transmitted in April of 2007.

Please contact us if you need any additional information or would like to discuss the project.

Thank you for your assistance.
Ron Bryant
816-822-3023

Scope of Services
SCR Catalyst Recommendations

Minnkota Power Cooperative
Milton R Young Station
August 26, 2009

1. Minnkota Power Cooperative (MPC) operates two coal-fired electric generating units at the Milton R. Young Station. Both units are Babcock & Wilcox balanced-draft cyclone fired boilers burning 100% North Dakota lignite coal supplied from an adjacent mine. Unit 1 has a gross design output capacity of 257 MW and was initially placed into commercial service in 1970. Unit 2 has a gross original design output capacity of 477 MW and was initially put into service in 1977. The units are located approximately 40 miles northwest of Bismarck, ND.

2. MPC is performing a SCR cost estimate for both units as part of a NO_X BACT Study required by the North Dakota Department of Health. Because of the unique characteristics of North Dakota lignite, MPC is requesting assistant with SCR catalyst selection and sizing.

3. The scope of services MPC is requesting includes the following for both low dust and tail end SCR applications for both units:

    a. Size the reactors to provide the optimal gas velocity and NO_X reduction for the specific applications.

    b. Provide anticipated guarantees for NO_X reduction for the specific applications. Nominal anticipated NO_X concentration entering the reactors is 0.5 lb/million Btu. Nominal desired maximum NO_X concentration exiting the reactors is 0.05 lb/million Btu.

    c. Provide anticipated guarantees for ammonia usage and ammonia slip for the specific applications. The maximum ammonia slip should not exceed 5 ppm.

    d. Provide anticipated guarantees for catalyst deactivation rate and life (number of operating hours between catalyst replacement). It is desired to have a 3 year interval between catalyst layer change-out. If a 3 year interval is not achievable, provide the longest interval the catalyst vendor is able to guarantee.

    e. Provide budgetary pricing for the recommended catalyst.

    f. Review preliminary ductwork layout drawings to determine if any fatal flaws are apparent.

4. Additional design parameters and flue gas testing results are included as an attachment. It is the intent that Dr. Steve Benson and other team members will discuss the test data and related implications of the catalyst selection and design with the catalyst supplier.

5. Please provide requested items by September 18, 2009.

FINAL REPORT:

ASSESSMENT OF PARTICULATE CHARACTERISTICS UPSTREAM AND DOWNSTREAM OF ESP AND WET FGD

Prepared for:

Andrew Freidt
Permit and Compliance Engineer
Minnkota Power Cooperative, Inc.
Milton R. Young Power Station
Center, ND

Prepared by:

Margaret Laumb, Research Engineer and
Steve Benson, President
Microbeam Technologies, Inc.

John Kay and
Don McCollor
UND Energy and Environmental Research Center

Frank Bowman and
Dennis Sisk
UND Chemical Engineering

July 1, 2009

Shipping:
4200 James Ray Drive, Ste. 191
Grand Forks, ND 58203

Mailing:
PO Box 14758
Grand Forks, ND 58208-4758

Phone: 701-777-6530
Fax: 701-777-6532
info@microbeam.com

EXECUTIVE SUMMARY

Particulate sampling was conducted at Minnkota Power Cooperative's Milton R. Young plant to determine the particulate size and composition distribution of samples collected upstream of the ESP, upstream of the wet scrubber, and downstream of the wet scrubber. Emphasis was placed on determining the fate of sodium, potassium, and calcium since these elements can cause significant plugging and deposition problem.

During the testing, operating conditions of the plant were constant and there was no gas bypass. The coal fired during the testing remained relatively consistent. The as-received ash content ranged from 7.73 to 7.89%. Sodium oxide content of the ash ranged from 7.22 to 7.57% and the base-to-acid ratio decreased the last two days of testing (a result of a decrease in CaO content and an increase in SiO_2 and Al_2O_3 levels). Sampling upstream of the ESP and scrubber were conducted using a combination multicylones and impactors. The cyclones collected sized fractions of larger particles (greater than one to five microns) and the impactor collected the sub-micron particulate. Sampling downstream of the scrubber was conducted with a single cyclone followed by a 13-stage advanced impactor. In addition, the submicron particle number concentration was measured using a scanning mobility particle sizer (SMPS).

The results of the particulate mass information indicated a high loading at the ESP inlet of 4.96×10^6 µg/dscm, a scrubber inlet loading of 1.1×10^4 µg/dscm, and a scrubber outlet loading of 1.08×10^4 µg/dscm. These results show very little overall removal of the submicron particulate across the wet scrubber system. A significant fraction of the particulate was removed by the ESP, with a removal efficiency of 99.76%.

The size distribution of the particulate collected upstream of the ESP and upstream of the scrubber was multi-modal as summarized below:

- Upstream of the ESP there were at least three modes – a larger mode at 40 to 50 µm, a second mode at just under 10 µm, and third mode at about 1 µm. The larger particles are typically derived from mineral grains in the coal such as quartz, clays, and pyrite. The intermediate-sized particles are typically derived from small minerals and organically associated elements. The smaller mode (about one-micron and smaller) contains fine particles and condensed vapor phase species.
- Upstream of the scrubber there were two distinct modes – a larger mode between 8 to 10 µm and another mode centered at about 1 to 2 µm in diameter. The smaller mode is typically condensed vapor phase and small particles.
- Downstream of the scrubber, the primary mode centered at about 0.5 to 0.7 µm, and another possible mode occurred at 3 µm and larger.
- Particle number distributions were as follows:
    - Inlet to the ESP – between 1×10^7 to 10^8 particles per dry normal cubic centimeter (dncc);
    - Inlet to the scrubber is 10^5 particles/dncc;
    - Outlet of the scrubber 7×10^5 particles/dncc.

- Particle number distributions into the nanometer scale (1 μm = 1000 nm) was found to be as high as 10^5 particles/dncc.

Particle composition distributions of the particulate were determined for each of the major elements. The results were reported as μg/dscm of the element as illustrated in the Appendix and in the figures in the text.

- Upstream of the ESP the composition trends for sodium, potassium, calcium and sulfur showed greater concentrations of these elements in the particles that are smaller than 10 μm, with a significant increase in concentration in the flue gas at a particle size of less than 2 μm. There is another increase at 0.1 μm.
- Upstream of the scrubber the compositional trends for sodium, potassium, calcium and sulfur show higher levels at the 1 μm level. The ESP was effective in removing larger-sized particles, as well as some of the 0.1 μm particles. However, in the intermediate 1 μm particles, the ESP is not as effective in removing the particles.
- Downstream of the scrubber the composition size distribution determined for sodium, potassium, calcium and sulfur showed significant levels of sodium and sulfur in size fraction finer than 1 μm. The DLPI sampling system provides very accurate sizing data in the submicron size range. Other elements such as aluminum, silicon and iron show a significant depletion below 1 μm.

Comparison of the characteristics of the particles in terms of mass and composition indicate that, at the time of the testing, the total average mass of the particulate was about 10,800 μg/dscm. The particulate consisted mainly of sodium, potassium, and sulfur. The total quantity of sodium and potassium exiting was between 2000 to 3000 μg/dscm.

INTRODUCTION AND BACKGROUND

Microbeam Technologies, Inc. (MTI) teamed with Energy & Environmental Research Center (EERC) and the Chemical Engineering Department at the University of North Dakota (UND-ChE) to determine the abundance and composition of particulate materials produced at Unit #2 of Minnkota Power Cooperative's Milton R. Young Station (MRY), equipped with an electrostatic precipitator (ESP) and a wet flue gas desulfurization (FGD) system.

Very small particles or aerosols are produced upon combustion of all fuels. These particles have diameters less than ten microns, and in many cases less than one micron. They are formed during the combustion process - when the fuel is exposed to high temperatures and gaseous environments, impurities within the fuel are vaporized. When the gas is cooled, the vaporized species condense to form the small particles or aerosols.

Abundance and composition of the aerosols vary depending upon the fuel type and the combustion system. High-temperature combustion systems, such as cyclone-fired systems, produce higher levels of vaporized species than other combustion system types. Fuels (such as biomass or lignite) that contain high levels of alkali (sodium and potassium) and alkaline earth elements (calcium and magnesium) are especially likely to produce abundant aerosols in the cooler regions of combustion systems, such as air pollution control systems.

Collection of aerosol particles finer than five- to ten-microns in electrostatic precipitators and scrubbers is difficult because physical processes used by these technologies to capture particles are very limited in the one-tenth to five-micron size range. Detailed discussion of the processes can be found in the appendix of this report.

This report contains the results of analyses performed on coal and ash samples collected during field testing at MRY Unit 2. The work was performed to determine the properties (including size, mass, and composition) of particulates collected upstream and downstream electrostatic precipitator and wet FGD.

GOALS AND OBJECTIVES

Objectives of the project were as follows: 1) obtain representative, size-segregated samples of particulate material, including super- and sub-micron particulate, from three locations; 2) perform analyses on these samples to determine the size, mass, and composition distribution; and 3) provide an assessment of the probable impact of particulate inorganic species on the performance of NO_x reduction technologies.

SAMPLE COLLECTION AND CHARACTERIZATION

Sampling

Particulate material in the flue gas was collected and measured upstream and downstream of the MRY electrostatic precipitator, also denoted as the "air heater inlet" and at the wet flue gas desulfurization (FGD) or "scrubber inlet". Multi-cyclone samples were taken at the locations

during the impactor testing. Sampling at the ESP inlet and scrubber inlet were conducted at single port locations and traversed for depth. The sampling at the ESP inlet was performed using two different ports; the total sampling time was divided equally between the selected sampling depths. The sampling depths, along with a summary of sampling activities, are summarized in **Table 1**. Sampling locations are shown on a simplified schematic in **Figure 1**.

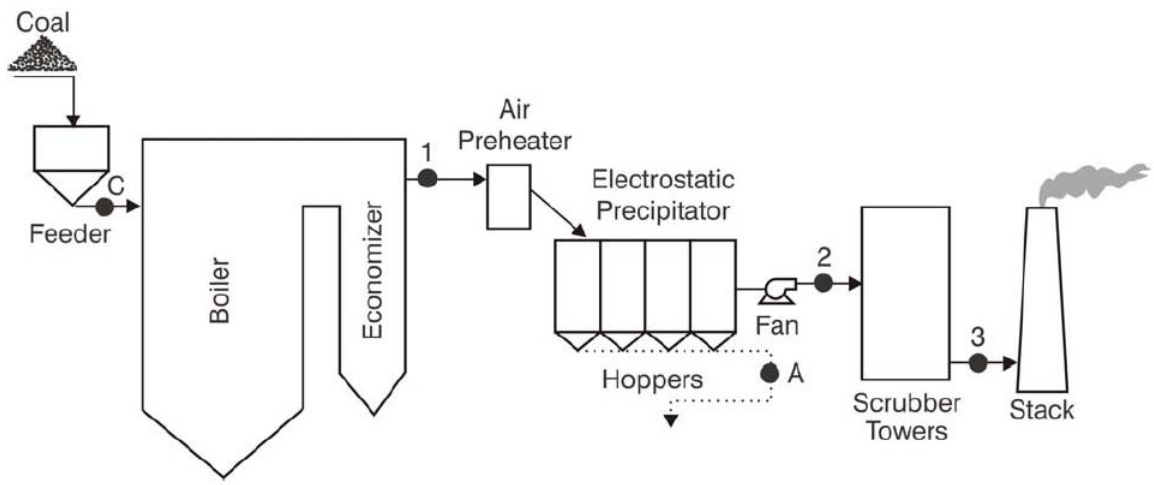


Figure 1. Location of sampling points at MRY Unit 2.

Table 1. Summary of sampling activities at MRY Unit 2.

Test	Location	Date	Start Time	End Time	Duration (minutes)	Sampling Depth (inches)	Notes
IMP/MC Test #1	ESP inlet	3/17/2009	15:40	16:23	43	56,112,161	Figure 1 – point 1
IMP/MC Test #5	ESP inlet	3/19/2009	13:37	13:49	12	56,112,168	Figure 1 – point 1
IMP/MC Test #2	ESP outlet/B scrubber inlet	3/16/2009	16:35	18:13	98	48,102,161	Figure 1 – point 2
IMP/MC Test #3	ESP outlet/B scrubber inlet	3/17/2009	13:47	15:47	120	48,102,161	Figure 1 – point 2
IMP/MC Test #4	ESP outlet/B scrubber inlet	3/18/2009	13:00	15:00	120	48,102,161	Figure 1 – point 2
IMP/MC Test #6	ESP outlet/B scrubber inlet	3/19/2009	12:20	14:20	120	48,102,161	Figure 1 – point 2
SMPS	B Scrubber outlet	3/18/2009			240	~84	Figure 1 – point D
SMPC	B Scrubber outlet	3/19/2009			240	~84	Figure 1 – point D
Dekati "SEM"	B Scrubber outlet	3/18/2009	16:30	17:30	60		*Not weighed* Figure 1 – point D
Dekati Run #1	B Scrubber outlet	3/18/2009	22:00	23:15	75		Figure 1 – point D
Dekati Run #2	B Scrubber outlet	3/19/2009	13:00	16:00	180		Figure 1 – point D
Sample	**Location**	**Date**	**Time Collected**			**Notes**	
ESP ash sample	3B1 - row 1	3/19/2009	14:00			Figure 1 – point A	
ESP ash sample	3B2 - row 2	3/19/2009	14:00			Figure 1 – point A	
ESP ash sample	3B3 - row 3	3/19/2009	14:00			Figure 1 – point A	
ESP ash sample	3B4 - row 4	3/19/2009	14:00			Figure 1 – point A	
Coal sample	Feeder 1	3/16/2009	17:05			Figure 1 – point C	
Coal sample	Feeder 6	3/16/2009	17:10			Figure 1 – point C	
Coal sample	Feeder 7	3/16/2009	17:15			Figure 1 – point C	
Coal sample	Feeder 12	3/16/2009	17:00			Figure 1 – point C	
Coal sample	Feeder 1	3/17/2009	14:40			*Labeled 13:40 - Assumed to be 14:40* Figure 1 – point C	

Sample	Location	Date	Time Collected	Notes
Coal sample	Feeder 6	3/17/2009	14:50	Figure 1 – point C
Coal sample	Feeder 7	3/17/2009	14:55	Figure 1 – point C
Coal sample	Feeder 12	3/17/2009	14:30	Figure 1 – point C
Coal sample	Feeder 1	3/17/2009	17:55	Figure 1 – point C
Coal sample	Feeder 6	3/17/2009	18:00	Figure 1 – point C
Coal sample	Feeder 7	3/17/2009	18:30	Figure 1 – point C
Coal sample	Feeder 12	3/17/2009	17:50	Figure 1 – point C
Coal sample	Feeder 1	3/18/2009	14:10	Figure 1 – point C
Coal sample	Feeder 6	3/18/2009	16:25	Figure 1 – point C
Coal sample	Feeder 7	3/18/2009	16:15	Figure 1 – point C
Coal sample	Feeder 12	3/18/2009	14:00	Figure 1 – point C
Coal sample	Feeder 1	3/18/2009	19:50	Figure 1 – point C
Coal sample	Feeder 6	3/18/2009	19:45	Figure 1 – point C
Coal sample	Feeder 7	3/18/2009	19:45	Figure 1 – point C
Coal sample	Feeder 12	3/18/2009	19:50	Figure 1 – point C
Coal sample	Feeder 1	3/19/2009	14:15	Figure 1 – point C
Coal sample	Feeder 6	3/19/2009	14:30	Figure 1 – point C
Coal sample	Feeder 7	3/19/2009	14:20	Figure 1 – point C
Coal sample	Feeder 12	3/19/2009	14:10	Figure 1 – point C

Multicyclone Sampling

Size-fractionated fly ash samples were collected with a Southern Research Institute multi-staged multi-cyclone placed in the duct work at the air heater inlet (ESP inlet). The multicyclone consists of five cyclones, with decreasing d50 cut points, placed in series. The d50 particle size for each test is determined by the temperature and gas flow rate through the cyclone. For the testing at the MRY station, three of the five cyclone stages were used, along with the impactor, to collect selected coarser and finer fractions simultaneously. Size cut data for the multicyclone sampling performed at the air heater inlet are shown in **Table 2**.

Impactor Sampling

Size-fractionated fly ash samples were collected with a University of Washington seven-stage impactor placed in the gas stream behind the three multi-cyclone stages at the ESP inlet, and was used without multi-cyclone stages at the ESP outlet/scrubber inlet sampling location. The impactor is a round hole, multiple jet-type impactor with seven stages and a backup filter. Each stage has a decreasing d50 cut point. The d50 particle sizes for each test are determined by temperature and gas flow rate through the impactor. Cut points for the impactor at the air heater inlet are shown in **Table 2**. Cut points for the impactor at the scrubber inlet are shown in **Table 3**.

Table 2. D50 cut points for sampling (multicyclone and impactor) at the air heater inlet.

03/17/2009			3/19/2009		
Stage	Mass, g	d_{50} Cut Point, µm	Stage	Mass, g	d_{50} Cut Point, µm
Multicyclone			Multicyclone		
1	1.45614	9.70	1	0.49872	9.61
3	0.21646	4.07	3	0.05665	4.02
4	0.07816	2.58	4	0.02363	2.55
Impactor			Impactor		
1	0.00178	14.24	1	0.00051	14.13
2	0.00482	10.77	2	0.00179	10.69
3	0.01474	3.95	3	0.00542	3.92
4	0.02174	2.31	4	0.00624	2.286
5	0.05468	1.33	5	0.00769	1.31
6	0.03949	0.58	6	0.01154	0.57
7	0.03260	0.14	7	0.01136	0.13
Filter	0.04926	–	Filter	–	–

Table 3. D50 cut points for sampling (impactor) at the B scrubber inlet.

	03/16/2009		03/17/2009		03/18/2009		03/19/2009	
Impactor Stage	Mass, g	d_{50} Cut Point, µm	Mass, g	d_{50} Cut Point, µm	Mass, g	d_{50} Cut Point, µm	Mass, g	d_{50} Cut Point, µm
1	0.00228	13.54	0.00105	12.99	0.00555	13.06	0.00534	13.04
2	0.00503	10.22	0.00345	9.80	0.00337	9.85	0.00358	9.83
3	0.00183	3.81	0.00224	3.65	0.00278	3.67	0.00195	3.66
4	0.00192	2.03	0.00326	1.92	0.00259	1.93	0.00191	1.93
5	0.00336	1.15	0.00410	1.07	0.00311	1.08	0.00278	1.08
6	0.00110	0.54	0.00174	0.45	0.00146	0.50	0.00145	0.50
7	–	0.17	–	0.16	–	0.16	–	0.16
Filter	0.00008	–	–	–	–	–	–	–

DLPI Sampling

The Dekati Low Pressure Impactor (DLPI) is a state-of-the-art 13-stage cascade impactor for measuring gravimetric particle size distribution of very small particles. It size-classified particles from 10 microns (µm) to 30 nm, and a filter stage accessory enables collection of particles smaller than 30 nm in diameter. **Figure 2** shows the impactor and stages. The d50 cut points for sampling with the DLPI are shown in **Table 4**.

Figure 2. Dekati Low-Pressure Impactor.

Table 4. D50 cut points for sampling (Dekati Low Pressure Impactor) at the B scrubber outlet.

Stage #	$D_{50\%}$ [1] (μm)
13	10
12	6.8
11	4.4
10	2.5
9	1.6
8	1
7	0.65
6	0.4
5	0.26
4	0.17
3	0.108
2	0.06
1	0.03

[1] $D_{50\%}$ is the particle diameter where half of these particles pass through the stage and half are captured by the stage.

SMPS Sampling

Sampling at the scrubber outlet was conducted utilizing the scanning mobility particle scanning (SMPS) system that consists of an electrostatic classifier (EC), a condensation particle counter (CPC), and data analysis center (DAC). A schematic of the system is shown in **Figure 3**. The EC classifies the particles, and the concentration is measured by the CPC. The DAC includes a personal computer with custom software, which controls individual instruments and performs data reduction. The components of the SMPS system, particularly the CPC, function normally at about 35°C (95°F). However, the EC does not appear to be too sensitive to temperature conditions.

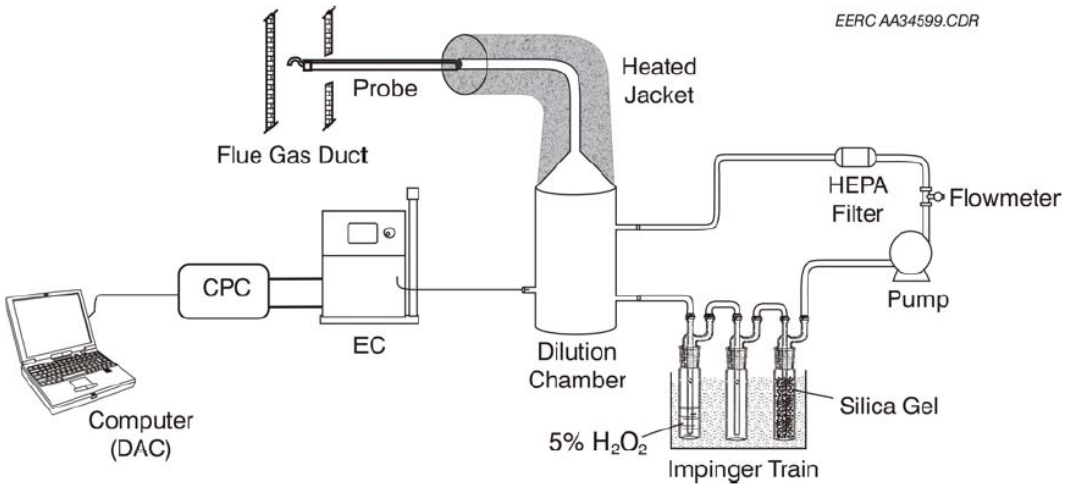


Figure 3. Schematic of the scanning mobility particle scanning (SMPS) system used at the B scrubber outlet.

The procedure for making particulate measurements with the SMPS system is conceptually simple, although manipulating the entire system is quite complex. Typically, flue gas enters the dilution chamber and is mixed with excess air fed through an external pump and at the flow rate of about 45–50 liters per minute (lpm). Dilution air from the pump passes through a HEPA filter to remove any particles that may be in the air. Part of the dilution air is sucked back from the dilution chamber and passed through an impinger train; the wet impinger contains about 250 milliliters (mL) of a 5% hydrogen peroxide (H_2O_2) solution, and the air is dried by passing it through a silica gel flask. The air from the flask is circulated through the pump back to the dilution chamber, and the recirculation process continues for the duration of the measurement. At the bottom of the dilution chamber, a ¼-inch line extracts a sample of the diluted flue gas and delivers it to the EC. The flow rates and pressure drop used in the EC are shown in **Table 5**.

Table 5. Electrostatic classifier (EC) flow meter set points.

Parameter	Monodisperse Air	Sheath Air	Excess Air
Flow Rate, lpm	0.3	3	3
Output, volts	2.305	2.735	2.627
Pressure Drop, cm H_2O	9	N/A*	N/A

* Not applicable.

Measurement does not begin until the CPC is running normally and flow is stable. At a typical working temperature of about 35°C (95°F), indicator lights are checked to ensure all parts are functioning properly (including the liquid level, laser, optics, pump flow, condenser, and saturator). The liquid used in running the CPC is n-butyl alcohol (n-butanol).

Analysis

Table 6 contains a full list of the samples collected and analyses performed. Samples collected were analyzed to determine chemical composition. Scanning electron microscopy with

x-ray elemental analysis was performed on the ash samples. Information gained from this method included images and point and area (average) analyses. This type of analysis is called "morphology" because it combines image analysis for features of interest with chemical analysis.

The multicyclone samples were analyzed using bulk chemical anlaysis at EERC. The bulk analysis involved microwave digestion of the ash followed by inductively-coupled plasma-mass spectrometry (ICP-MS). Concentrations of the major elements sodium, potassium, phosphorus, calcium, magnesium and iron were determined.

The coal samples collected during the tests were composited for standard ASTM tests (proximate and ash composition or "mineral ash" analysis) and for computer-controlled scanning electron microscopy (CCSEM) analysis, which provides information on mineral types, abundance, and sizes within the coal.

Table 6. List of samples and analyses performed.

Sample #	Date	Sample	Sample Location	Analysis
09-083	3/17/2009	IMP/MC Test #1 - Cyclone nozzle	ESP inlet (A/H inlet)	None
09-084	3/17/2009	IMP/MC Test #1 - Cyclone #1	ESP inlet (A/H inlet)	Morphology
09-085	3/17/2009	IMP/MC Test #1 - Cyclone #3	ESP inlet (A/H inlet)	Morphology
09-086	3/17/2009	IMP/MC Test #1 - Cyclone #4	ESP inlet (A/H inlet)	Morphology
09-087	3/17/2009	IMP/MC Test #1 - Impactor Stage 1	ESP inlet (A/H inlet)	Morphology
09-088	3/17/2009	IMP/MC Test #1 - Impactor Stage 2	ESP inlet (A/H inlet)	Morphology
09-089	3/17/2009	IMP/MC Test #1 - Impactor Stage 3	ESP inlet (A/H inlet)	Morphology
09-090	3/17/2009	IMP/MC Test #1 - Impactor Stage 4	ESP inlet (A/H inlet)	Morphology
09-091	3/17/2009	IMP/MC Test #1 - Impactor Stage 5	ESP inlet (A/H inlet)	Morphology
09-092	3/17/2009	IMP/MC Test #1 - Impactor Stage 6	ESP inlet (A/H inlet)	Morphology
09-093	3/17/2009	IMP/MC Test #1 - Impactor Stage 7	ESP inlet (A/H inlet)	Morphology
09-094	3/17/2009	IMP/MC Test #1 - Impactor outlet (backup filter)	ESP inlet (A/H inlet)	Morphology
09-097	3/18/2009	Dekati Run #1 - Stage 1	Scrubber outlet	Morphology
09-098	3/18/2009	Dekati Run #1 - Stage 2	Scrubber outlet	Morphology
09-099	3/18/2009	Dekati Run #1 - Stage 3	Scrubber outlet	Morphology
09-100	3/18/2009	Dekati Run #1 - Stage 4	Scrubber outlet	Morphology
09-101	3/18/2009	Dekati Run #1 - Stage 5	Scrubber outlet	Morphology
09-102	3/18/2009	Dekati Run #1 - Stage 6	Scrubber outlet	Morphology
09-103	3/18/2009	Dekati Run #1 - Stage 7	Scrubber outlet	Morphology
09-104	3/18/2009	Dekati Run #1 - Stage 8	Scrubber outlet	Morphology
09-105	3/18/2009	Dekati Run #1 - Stage 9	Scrubber outlet	Morphology
09-106	3/18/2009	Dekati Run #1 - Stage 10	Scrubber outlet	Morphology
09-107	3/18/2009	Dekati Run #1 - Stage 11	Scrubber outlet	Morphology
09-108	3/18/2009	Dekati Run #1 - Stage 12	Scrubber outlet	Morphology
09-109	3/18/2009	Dekati Run #1 - Stage 13	Scrubber outlet	Morphology
09-110	3/18/2009	Dekati "SEM" - Stage 1	Scrubber outlet	None
09-111	3/18/2009	Dekati "SEM" - Stage 2	Scrubber outlet	None
09-112	3/18/2009	Dekati "SEM" - Stage 3	Scrubber outlet	None
09-113	3/18/2009	Dekati "SEM" - Stage 4	Scrubber outlet	None
09-114	3/18/2009	Dekati "SEM" - Stage 5	Scrubber outlet	None
09-115	3/18/2009	Dekati "SEM" - Stage 6	Scrubber outlet	None
09-116	3/18/2009	Dekati "SEM" - Stage 7	Scrubber outlet	None
09-117	3/18/2009	Dekati "SEM" - Stage 8	Scrubber outlet	None

Table 6. List of samples and analyses performed.

Sample #	Date	Sample	Sample Location	Analysis
09-118	3/18/2009	Dekati "SEM" - Stage 9	Scrubber outlet	None
09-119	3/18/2009	Dekati "SEM" - Stage 10	Scrubber outlet	None
09-120	3/18/2009	Dekati "SEM" - Stage 11	Scrubber outlet	None
09-121	3/18/2009	Dekati "SEM" - Stage 12	Scrubber outlet	None
09-122	3/18/2009	Dekati "SEM" - Stage 13	Scrubber outlet	None
09-123	3/19/2009	Dekati Run #2 - Stage 1	Scrubber outlet	Morphology
09-124	3/19/2009	Dekati Run #2 - Stage 2	Scrubber outlet	Morphology
09-125	3/19/2009	Dekati Run #2 - Stage 3	Scrubber outlet	Morphology
09-126	3/19/2009	Dekati Run #2 - Stage 4	Scrubber outlet	Morphology
09-127	3/19/2009	Dekati Run #2 - Stage 5	Scrubber outlet	Morphology
09-128	3/19/2009	Dekati Run #2 - Stage 6	Scrubber outlet	Morphology
09-129	3/19/2009	Dekati Run #2 - Stage 7	Scrubber outlet	Morphology
09-130	3/19/2009	Dekati Run #2 - Stage 8	Scrubber outlet	Morphology
09-131	3/19/2009	Dekati Run #2 - Stage 9	Scrubber outlet	Morphology
09-132	3/19/2009	Dekati Run #2 - Stage 10	Scrubber outlet	Morphology
09-133	3/19/2009	Dekati Run #2 - Stage 11	Scrubber outlet	Morphology
09-134	3/19/2009	Dekati Run #2 - Stage 12	Scrubber outlet	Morphology
09-135	3/19/2009	Dekati Run #2 - Stage 13	Scrubber outlet	Morphology
09-136	3/18/2009	IMP Test #4 - Inlet nozzle	ESP outlet/scrubber inlet	Morphology
09-137	3/18/2009	IMP Test #4 - Impactor stage 1	ESP outlet/scrubber inlet	Morphology
09-138	3/18/2009	IMP Test #4 - Impactor stage 2	ESP outlet/scrubber inlet	Morphology
09-139	3/18/2009	IMP Test #4 - Impactor stage 3	ESP outlet/scrubber inlet	Morphology
09-140	3/18/2009	IMP Test #4 - Impactor stage 4	ESP outlet/scrubber inlet	Morphology
09-141	3/18/2009	IMP Test #4 - Impactor stage 5	ESP outlet/scrubber inlet	Morphology
09-142	3/18/2009	IMP Test #4 - Impactor stage 6	ESP outlet/scrubber inlet	Morphology
09-143	3/18/2009	IMP Test #4 - Impactor stage 7	ESP outlet/scrubber inlet	Morphology
09-144	3/18/2009	IMP Test #4 - Impactor outlet (backup filter)	ESP outlet/scrubber inlet	Morphology
09-145	3/19/2009	IMP/MC Test #5 - Impactor stage 1	ESP inlet (A/H inlet)	Morphology
09-146	3/19/2009	IMP/MC Test #5 - Impactor stage 2	ESP inlet (A/H inlet)	Morphology
09-147	3/19/2009	IMP/MC Test #5 - Impactor stage 3	ESP inlet (A/H inlet)	Morphology
09-148	3/19/2009	IMP/MC Test #5 - Impactor stage 4	ESP inlet (A/H inlet)	Morphology
09-149	3/19/2009	IMP/MC Test #5 - Impactor stage 5	ESP inlet (A/H inlet)	Morphology
09-150	3/19/2009	IMP/MC Test #5 - Impactor stage 6	ESP inlet (A/H inlet)	Morphology
09-151	3/19/2009	IMP/MC Test #5 - Impactor stage 7	ESP inlet (A/H inlet)	Morphology
09-152	3/19/2009	IMP Test #5 - Impactor outlet (backup filter)	ESP inlet (A/H inlet)	Morphology
09-153	3/19/2009	IMP Test #6 - Inlet nozzle	ESP outlet/scrubber inlet	Morphology
09-154	3/19/2009	IMP Test #6 - Impactor stage 1	ESP outlet/scrubber inlet	Morphology
09-155	3/19/2009	IMP Test #6 - Impactor stage 2	ESP outlet/scrubber inlet	Morphology
09-156	3/19/2009	IMP Test #6 - Impactor stage 3	ESP outlet/scrubber inlet	Morphology
09-157	3/19/2009	IMP Test #6 - Impactor stage 4	ESP outlet/scrubber inlet	Morphology
09-158	3/19/2009	IMP Test #6 - Impactor stage 5	ESP outlet/scrubber inlet	Morphology
09-159	3/19/2009	IMP Test #6 - Impactor stage 6	ESP outlet/scrubber inlet	Morphology
09-160	3/19/2009	IMP Test #6 - Impactor stage 7	ESP outlet/scrubber inlet	Morphology
09-161	3/19/2009	IMP Test #6 - Impactor outlet (backup filter)	ESP outlet/scrubber inlet	Morphology
09-162	3/19/2009	IMP Test #5 - Film from stage 1	ESP outlet/scrubber inlet	Morphology
09-163	3/18/2009	IMP Test #4 - Film from stage 2 (bottom of jets)	ESP outlet/scrubber inlet	None

Table 6. List of samples and analyses performed.

Sample #	Date	Sample	Sample Location	Analysis
09-164	3/18/2009	IMP Test #4 - Film from stage 3 (bottom of jets)	ESP outlet/scrubber inlet	None
09-165	3/18/2009	IMP Test #4 - Film from stage 4 (bottom of jets)	ESP outlet/scrubber inlet	None
09-166	3/18/2009	IMP Test #4 - Film from stage 5 (bottom of jets)	ESP outlet/scrubber inlet	None
09-167	3/19/2009	IMP Test #6 - Film from stage 4 (back of jets)	ESP outlet/scrubber inlet	Morphology
09-168	3/19/2009	IMP/MC Test #5 - Cyclone stage 6	ESP inlet (A/H inlet)	Morphology
09-169	3/19/2009	IMP/MC Test #5 - Cyclone stage 7	ESP inlet (A/H inlet)	Morphology
09-170	3/19/2009	IMP/MC Test #5 - Cyclone #1	ESP inlet (A/H inlet)	Morphology
09-171	3/19/2009	IMP/MC Test #5 - Cyclone #3	ESP inlet (A/H inlet)	Morphology
09-172	3/19/2009	IMP/MC Test #5 - Cyclone #4	ESP inlet (A/H inlet)	Morphology
09-173	3/19/2009	IMP/MC Test #5 - Cyclone nozzle	ESP inlet (A/H inlet)	Morphology
09-174	3/19/2009	ESP Ash - Row 1 3B1	ESP	None
09-175	3/19/2009	ESP Ash - Row 2 3B2	ESP	None
09-176	3/19/2009	ESP Ash - Row 3 3B3	ESP	None
09-177	3/19/2009	ESP Ash - Row 4 3B4	ESP	None
09-178	3/16/2009	Coal sample – composite	Feeders	Proximate, ash composition, CCSEM
09-179	3/17/2009	Coal sample – composite	Feeders	Proximate, ash composition, CCSEM
09-180	3/18/2009	Coal sample – composite	Feeders	Proximate, ash composition, CCSEM
09-181	3/19/2009	Coal sample – composite	Feeders	Proximate, ash composition, CCSEM
09-184	3/16/2009	IMP Test #2 - Impactor stage 1	ESP outlet/scrubber inlet	Morphology
09-185	3/16/2009	IMP Test #2 - Impactor stage 2	ESP outlet/scrubber inlet	Morphology
09-186	3/16/2009	IMP Test #2 - Impactor stage 3	ESP outlet/scrubber inlet	Morphology
09-187	3/16/2009	IMP Test #2 - Impactor stage 4	ESP outlet/scrubber inlet	Morphology
09-188	3/16/2009	IMP Test #2 - Impactor stage 5	ESP outlet/scrubber inlet	Morphology
09-189	3/16/2009	IMP Test #2 - Impactor stage 6	ESP outlet/scrubber inlet	Morphology
09-190	3/16/2009	IMP Test #2 - Impactor stage 7	ESP outlet/scrubber inlet	Morphology
09-191	3/16/2009	IMP Test #2 - Impactor outlet (backup filter)	ESP outlet/scrubber inlet	Morphology
09-192	3/16/2009	IMP Test #2 - Impactor nozzle	ESP outlet/scrubber inlet	None
09-193	3/17/2009	IMP Test #3 - Impactor stage 1	ESP outlet/scrubber inlet	None
09-194	3/17/2009	IMP Test #3 - Impactor stage 2	ESP outlet/scrubber inlet	None
09-195	3/17/2009	IMP Test #3 - Impactor stage 3	ESP outlet/scrubber inlet	None
09-196	3/17/2009	IMP Test #3 - Impactor stage 4	ESP outlet/scrubber inlet	None
09-197	3/17/2009	IMP Test #3 - Impactor stage 5	ESP outlet/scrubber inlet	None
09-198	3/17/2009	IMP Test #3 - Impactor stage 6	ESP outlet/scrubber inlet	None
09-199	3/17/2009	IMP Test #3 - Impactor stage 7	ESP outlet/scrubber inlet	None
09-200	3/17/2009	IMP Test #3 - Impactor outlet (backup filter)	ESP outlet/scrubber inlet	None
09-201	3/17/2009	IMP Test #3 - Impactor nozzle	ESP outlet/scrubber inlet	None

RESULTS AND DISCUSSION

Coal Analysis and Plant Operating Conditions during Testing

The coal samples for each day were composited to form one larger sample; the four resulting composite coal samples were subjected to proximate and ash composition analyses. The results of the analyses are shown in **Table 7**. The coal was relatively consistent over the time period sampled. The as-received ash content ranged from 7.73 to 7.89%. Sodium content ranged from 7.22 to 7.57% and the base-to-acid ratio decreased the last two days of testing as a result of a decrease in CaO content and an increase in SiO_2 and Al_2O_3 levels.

Table 7. Proximate and ash composition analyses for four composite coal samples taken from MRY coal feeders on March 16 through 19, 2009.

	MTI 09-178 3/16/09 Composite		MTI 09-179 3/17/09 Composite		MTI 09-208 3/18/09 Composite		MTI 09-209 3/19/09 Composite	
Proximate (wt% in coal)	*As-rec'd*	*Dry*	*As-rec'd*	*Dry*	*As-rec'd*	*Dry*	*As-rec'd*	*Dry*
Total moisture	37.58		37.24		37.23		36.10	
Ash	7.89	12.64	7.85	12.51	7.84	12.49	7.73	12.10
Volatile matter	24.80	39.73	25.15	40.07	25.22	40.18	25.81	40.39
Fixed carbon	29.73	47.63	29.76	47.42	29.71	47.33	30.36	47.51
Heating value (BTU/lb)	6732	10785	6784	10810	6701	10676	6851	10721
Total sulfur	0.90	1.44	1.00	1.59	0.65	1.04	0.77	1.21
Ash Composition (wt% in ash)								
SiO2		26.92		26.08		34.46		31.06
Al2O3		8.78		8.81		11.61		10.63
TiO2		0.39		0.36		0.44		0.39
Fe2O3		11.17		12.96		7.75		8.49
CaO		15.23		14.99		14.01		15.26
MgO		4.55		4.38		4.37		4.70
K2O		1.24		1.55		1.68		1.46
Na2O		7.22		7.57		7.31		7.24
SO3		19.50		18.70		14.88		16.92
P2O5		0.45		0.40		0.33		0.47
SrO		0.45		0.43		0.41		0.44
BaO		0.72		0.55		0.61		0.63
MnO2		0.09		0.08		0.08		0.08
SiO2/Al2O3		***3.07***		***2.96***		***2.97***		***2.92***
Base/Acid		***1.09***		***1.18***		***0.76***		***0.88***

Figures 4 and **5** show the overall coal flow rate, along with the ash quantity and base-to-acid ratio determined with the Full-Stream Elemental Analyzer (FSEA) during the test period. The FSEA data was corrected for a 23-hour lag time between filling the hoppers and feeding coal to the cyclones. These data show a decrease in the base-to-acid ratio during the testing period. This was observed in the analysis of the four daily composite samples.

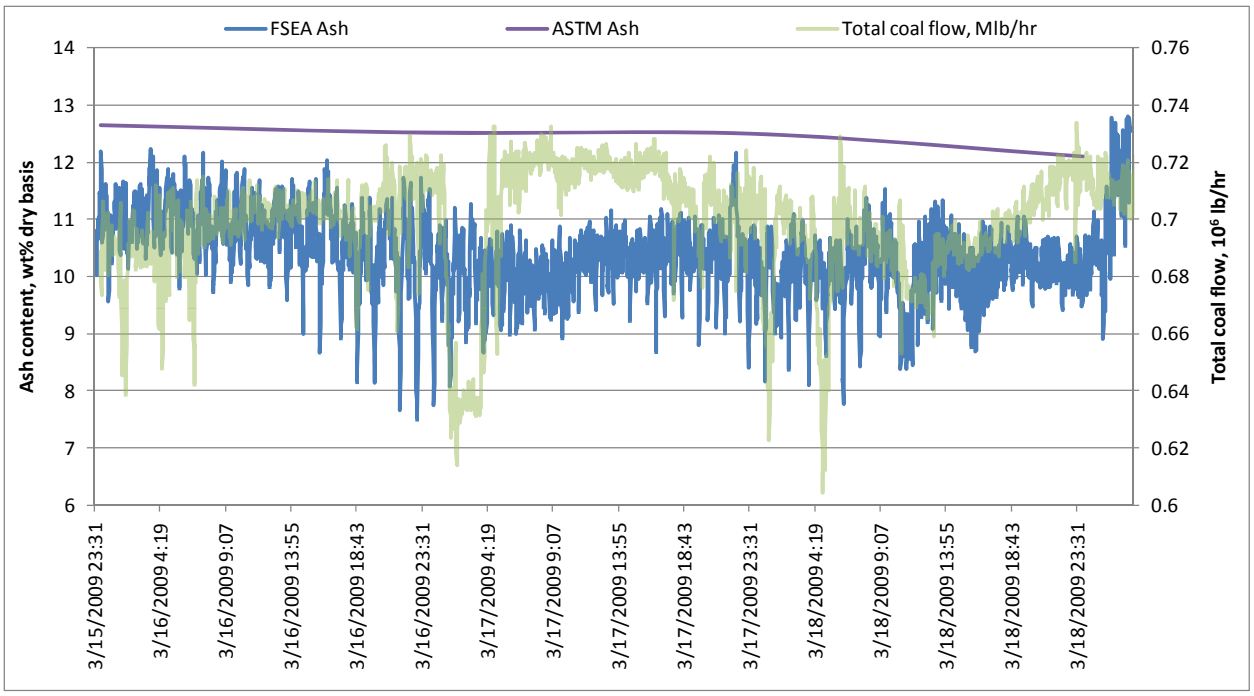


Figure 4. Coal belt flow and fuel ash quantity (determined with FSEA and by ASTM method on composite coal samples) during the testing. The FSEA data was corrected for a 23-hour lag time between filling the hoppers and estimated fuel fed to the cyclones.

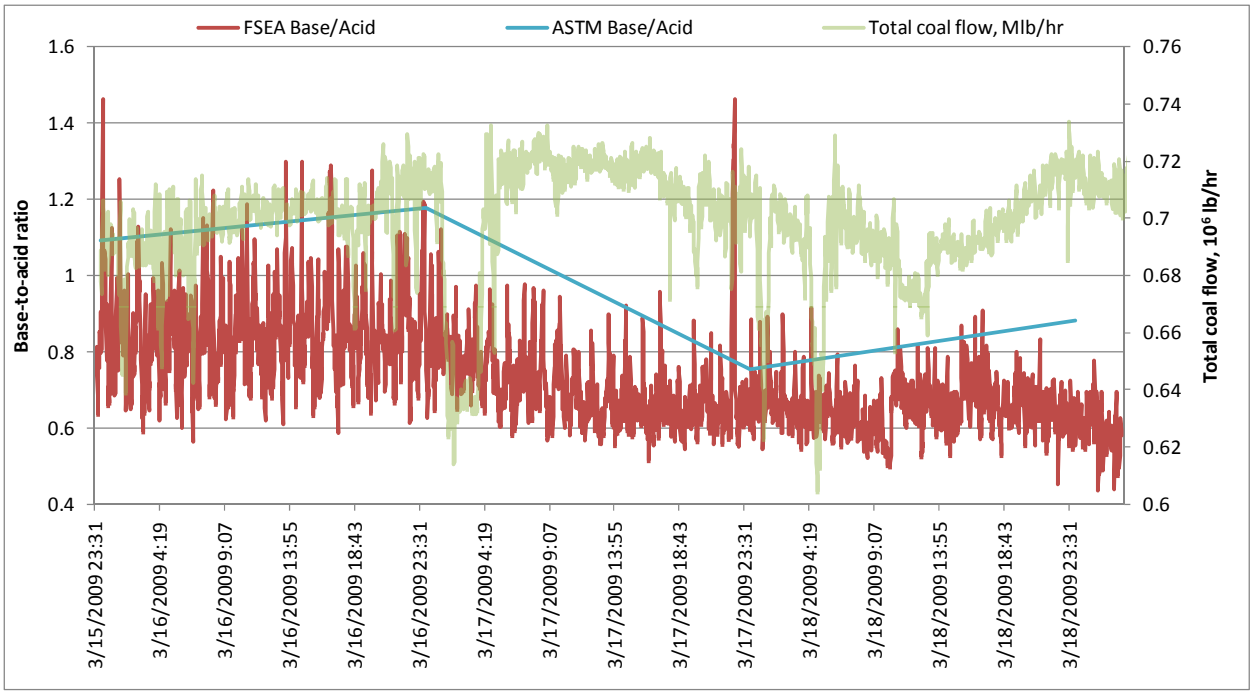


Figure 5. Coal belt flow and base-to-acid ratio (determined with FSEA and by ASTM ash composition analyses performed on composite coal samples) during the testing. The FSEA data was corrected for a 23-hour lag time between filling the hoppers and estimated fuel fed to the cyclones.

Particulate Mass and Number Distribution

Mass Distribution as Function of Location

The total mass loadings obtained with the multicyclone and impactors are illustrated in **Figure 6**. The results show a high average loading of 4.96×10^6 micrograms per dry standard cubic meter (µg/dscm) at the ESP inlet, and average scrubber inlet and outlet loadings of 1.1×10^4 µg/dscm and 1.08×10^4 µg/dscm, respectively. Significant removal of particulate occurred across the ESP, with removal efficiency of 99.76%. These results show that very little removal of particulate material has occurred across the wet scrubber system. This is consistent with past work conducted by Markowski and others (1983) (a literature review is contained in **Appendix B** of this report). The results are also summarized in **Table 8**.

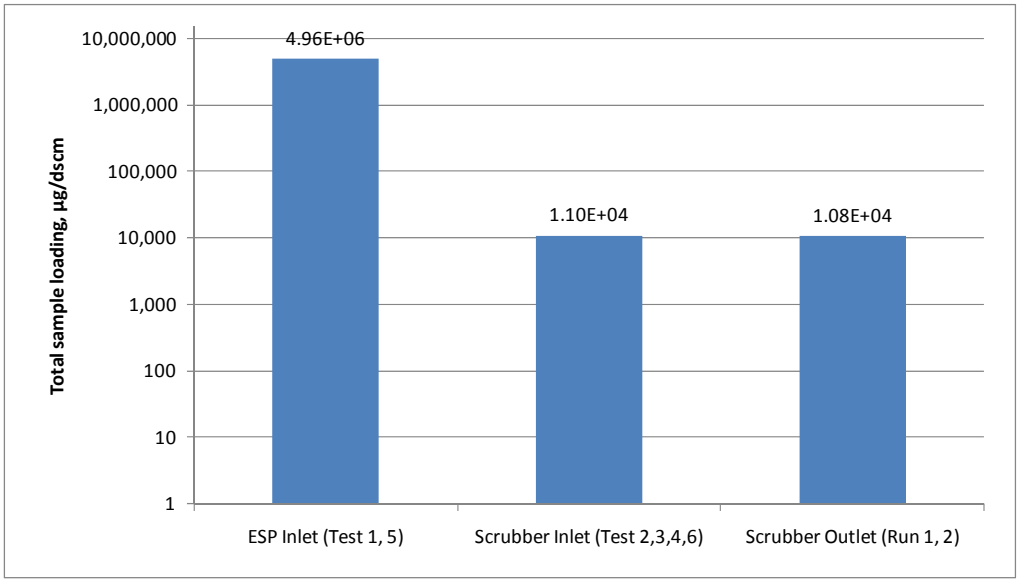


Figure 6. Total mass loadings at ESP inlet, wet scrubber inlet, and wet scrubber outlet.

Table 8. Total mass loadings for all testing conducted at ESP inlet, wet scrubber inlet, and wet scrubber outlet.

				Sampler loading		Total loading
Location	**Date**	**Test #**	**Sampler type**	**mg/dscm**	**µg/dscm**	**µg/dscm**
ESP inlet	3/17/2009	Test 1	Impactor	5.25E+02	5.25E+05	
ESP inlet	3/17/2009	Test 1	Cyclone	4.19E+03	4.19E+06	4.72E+06
Scrubber inlet	3/16/2009	Test 2	Impactor	1.25E+01	1.25E+04	1.25E+04
Scrubber inlet	3/17/2009	Test 3	Impactor	9.77E+00	9.77E+03	9.77E+03
Scrubber inlet	3/18/2009	Test 4	Impactor	1.15E+01	1.15E+04	1.15E+04
ESP inlet	3/19/2009	Test 5	Impactor	3.73E+02	3.73E+05	
ESP inlet	3/19/2009	Test 5	Cyclone	4.84E+03	4.84E+06	5.21E+06
Scrubber inlet	3/19/2009	Test 6	Impactor	1.03E+01	1.03E+04	1.03E+04
Scrubber outlet	3/18/2009	Run 1	Dekati Impactor		9109.506	9.11E+03
Scrubber outlet	3/19/2009	Run 2	Dekati Impactor		12560.87	1.26E+04

Particulate Mass Loading as a Function of Size

Sampling at the ESP inlet was conducted using both the multicyclone and the impactor. The cyclones are designed to capture larger-size particles and the impactor collects small particles. **Figure 7** shows the mass size distributions for the cyclone and impactor. The size distribution of the particulate at the ESP inlet is multimodal. The larger particles are typically derived from mineral grains in the coal such as quartz, clays, and pyrite minerals. The intermediate-sized particles are typically derived from small minerals and organically associated elements. Particles less than a micron in diameter and finer are condensed vapor phase species.

The sample collected on 3/17/09 show a multimodal size distribution, with a mode occurring at one to three microns, and another mode at 0.1 µm. The sample collected on 3/19/09 also has a multimodal distribution, with a shift in the finer mode from 0.1 µm to about 0.5 µm. This shift may be due to the change in fuel composition (the coal sample collected on 3/17/09 had a higher base-to-acid ratio as compared to the coal collected on 3/19/09).

The mass size distribution of the particulate collected upstream of the scrubber is illustrated in **Figure 8**. Sampling was conducted at this location on all four days of the period. The results show a bimodal distribution of particles with a mode between one to two microns and another mode between seven and eleven microns. A general trend of decreasing abundance of the modes during the testing is observed. The change in abundance is likely due to changes in coal ash composition. Coals sampled on 3/16 and 3/17 had higher base-to-acid ratios; coals on 3/18 and 3/19 had lower ratios.

The mass size distribution of the scrubber outlet particulate is illustrated in **Figure 9**. The size distribution shows a main mode at about 0.8 µm and possibly a minor larger mode of 2 µm. The particle size distribution is shifted to finer particles downstream of the scrubber and the smaller particle size mode appears to dominate the size distribution. The samples were collected on 3/18 and 3/19, when the coals fired had lower base-to-acid ratios.

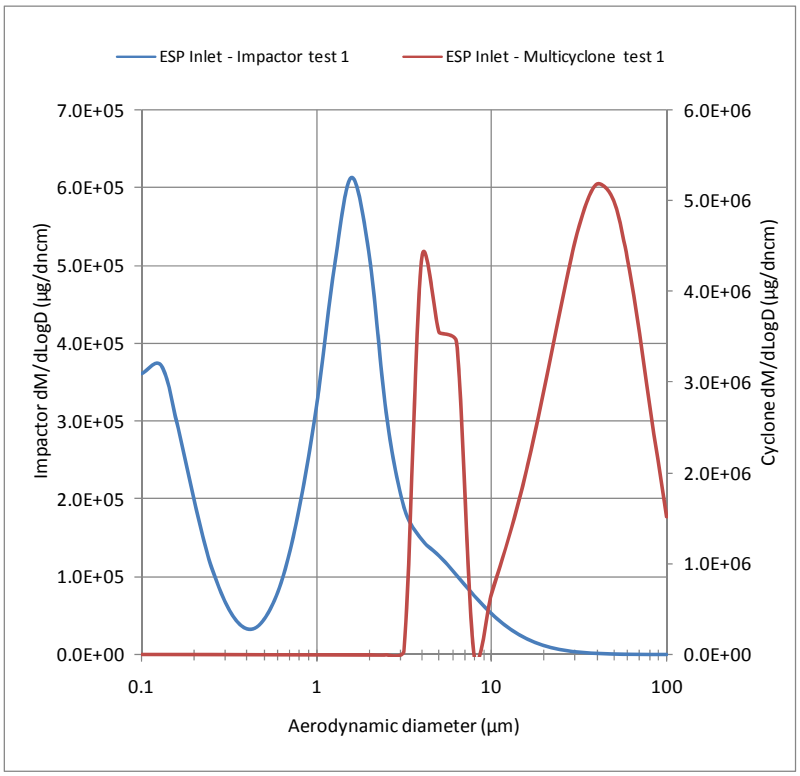


Figure 7a. Multicyclone and impactor data collected at ESP inlet on 3/17/09.

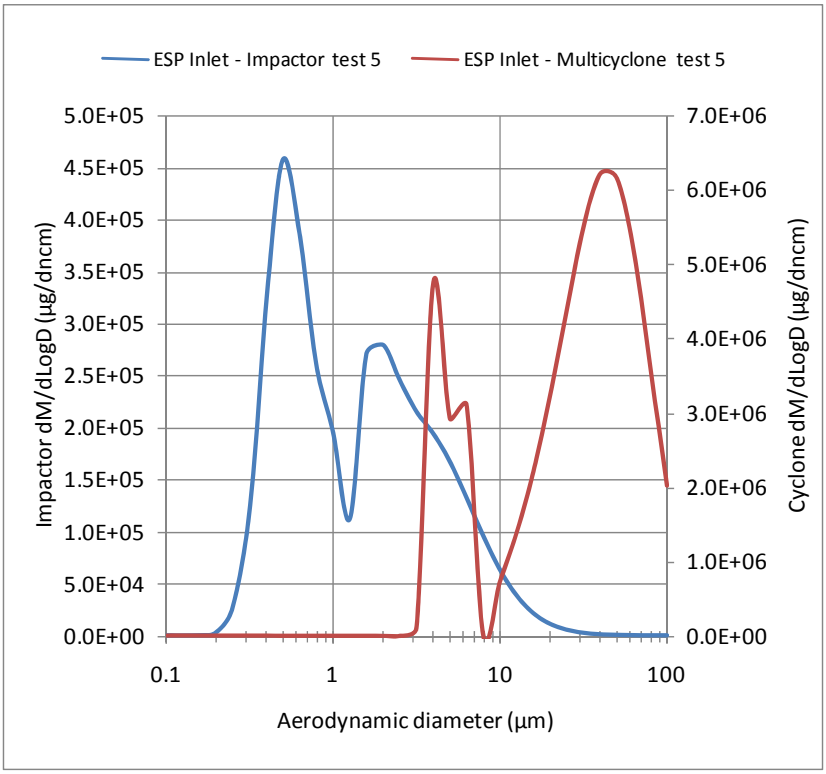


Figure 7b. Multicyclone and impactor data collected at ESP inlet on 3/19/09.

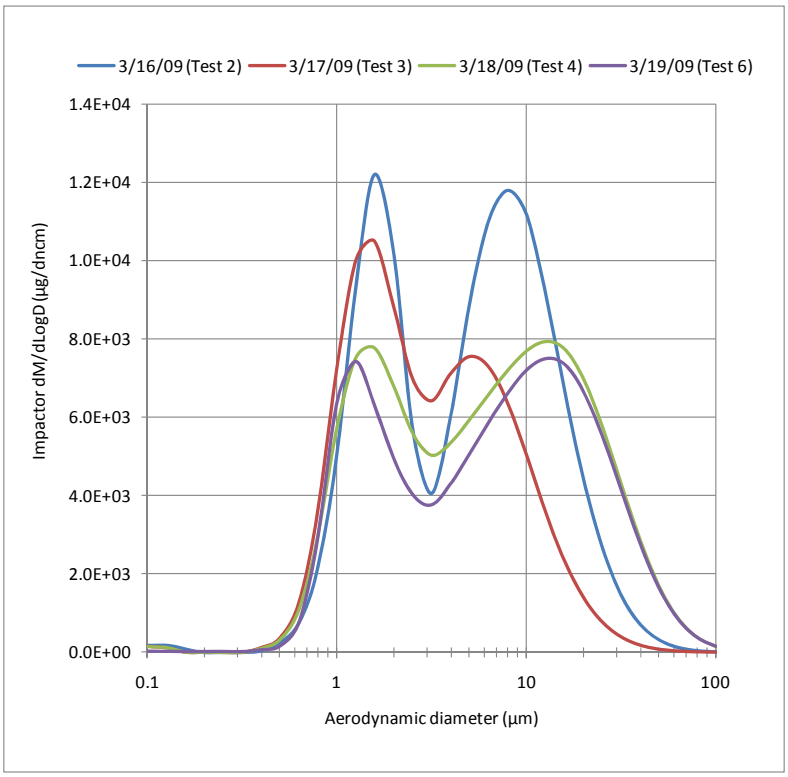


Figure 8. Mass versus size distribution of ash collected downstream of the ESP at the scrubber inlet.

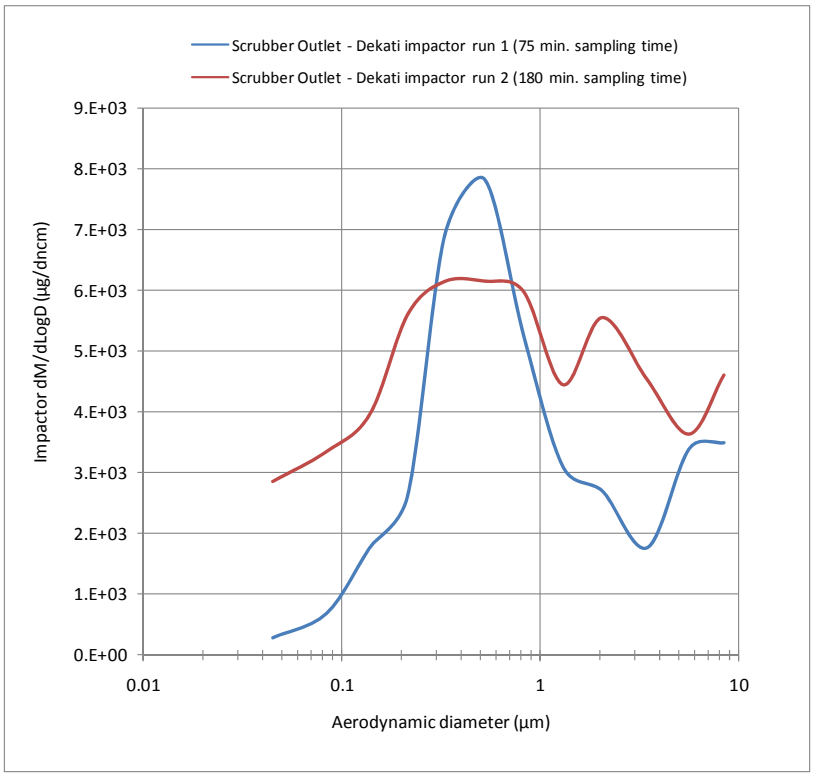


Figure 9. Mass distribution of particulate collected downstream of scrubber.

Particle Number Size Distribution

The number distributions for the particles are shown in **Figures 10** through **12** for the ESP inlet, scrubber inlet, and scrubber outlet. This information is shown as the number of particles per dry normal cubic centimeters (*not* cubic meters ash summarized above). This is the convention used by researchers.

The number of particle increases significantly with decreasing particles size. **Figure 10** shows the number of particles for the scrubber inlet. The ESP inlet sample had the highest number of particles in the smallest size fraction. The number of particles in the smallest size fraction at the scrubber inlet and outlet are similar – the slight increase in number at the scrubber outlet is likely to differences in sampling methods.

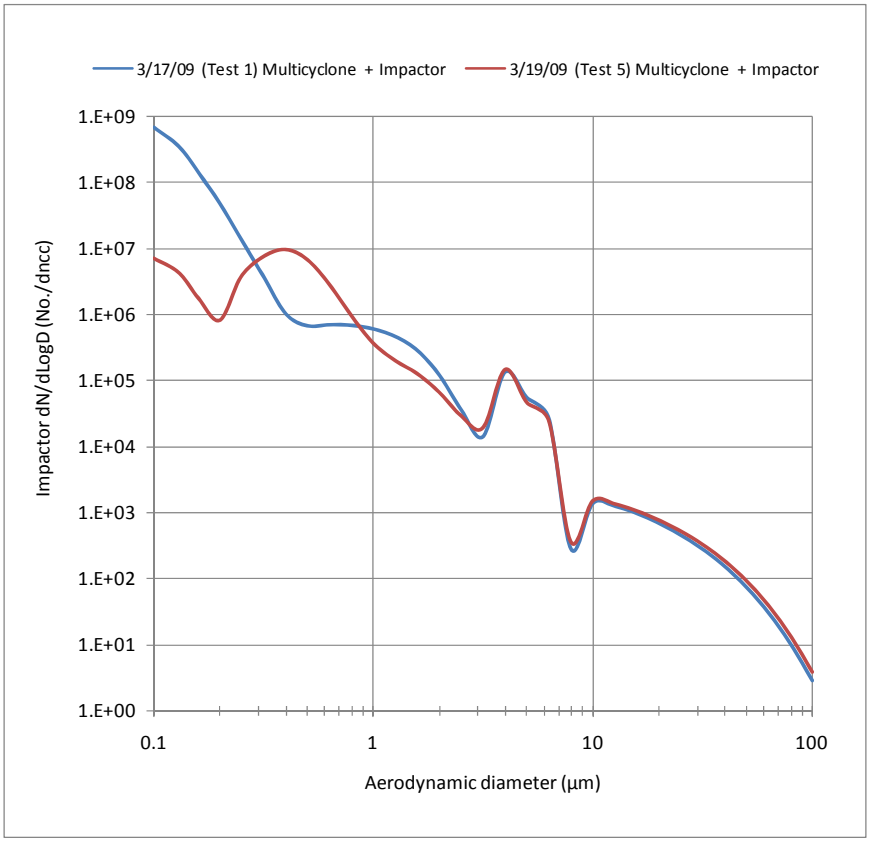


Figure 10. Number of particles as a function of size at the ESP Inlet.

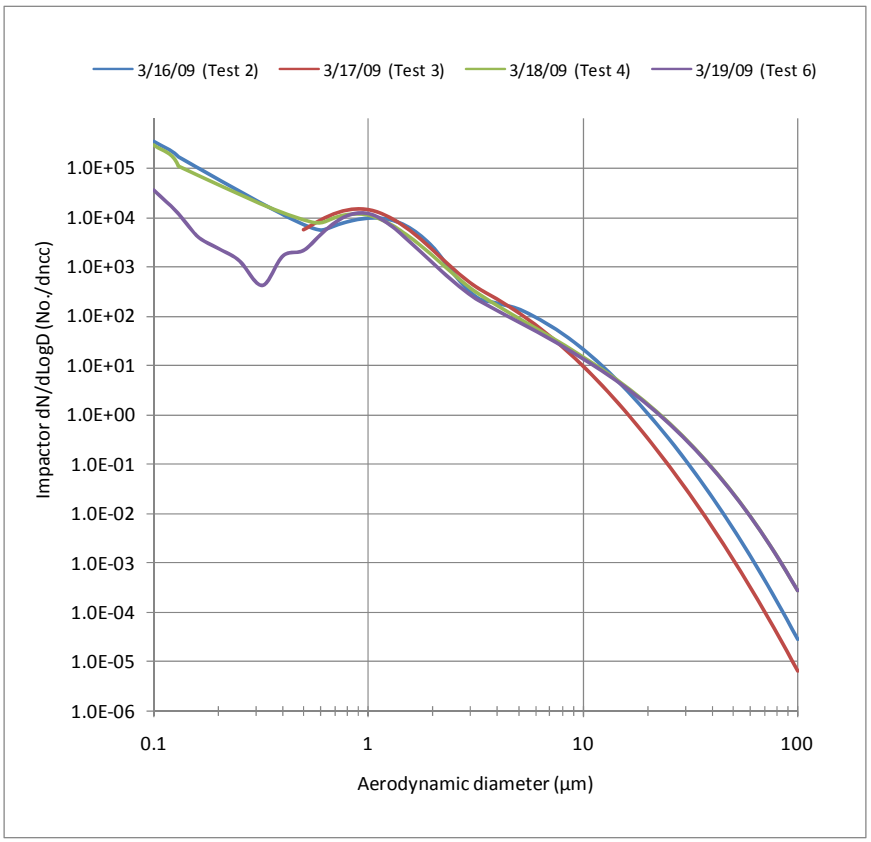


Figure 11. Number of particles as a function of size at the scrubber inlet.

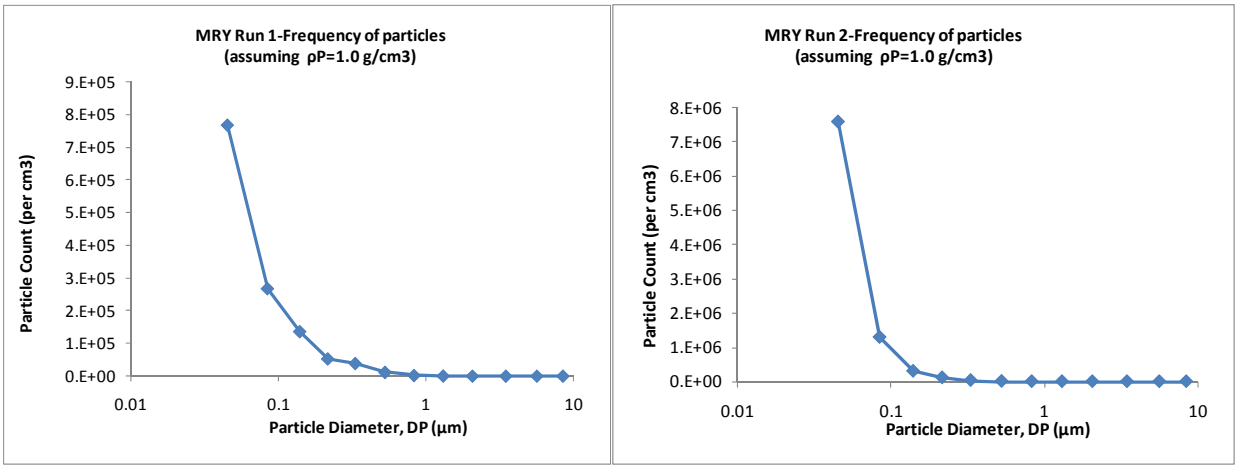


Figure 12. Number of particles as a function of size at the scrubber outlet.

Scanning Mobility Particle Scanning (SMPS)

Number-based concentration data obtained by the SMPS system at the scrubber outlet is shown in **Figures 13** and **14**. The data shown are for the on one good data set obtained during the sampling trip. A summary of the conditions at the sampling site that limited the ability of the SMPS to gain reliable data is listed in the Appendix.

The SMPS reports size data on a nanometer (nm) scale, not a micrometer (µm) scale. There are 1,000 nm in one micron. The data shown was obtained from a 10-sample test run, each 60 seconds apart, and includes two scans per sample: 60 seconds for the up scan and 30 seconds for the down scan. The scan window of the instrument covers a particle range of 16.5–605 nm (0.0165–0.605 µm).

Plots of the concentration versus particle diameter are given in **Figure 13** for number basis and in **Figure 14** for the mass basis. The number of particles observed using the SMPS is larger than that observed for the impactors but it is generally consistent the impactor data.

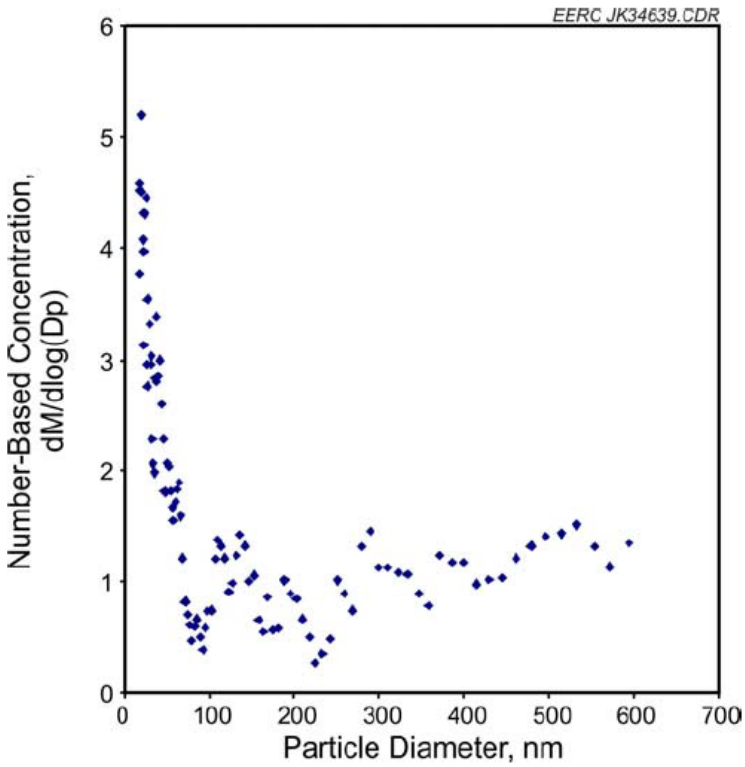


Figure 13. Plot of number-based particle concentration as a function of particle diameter (nanometers).

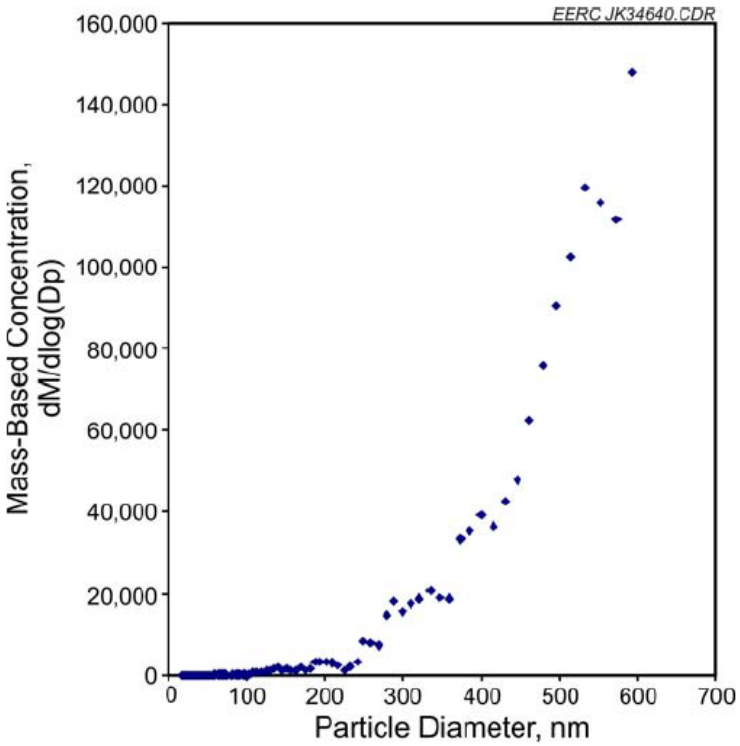


Figure 14. Plot of mass-based particle concentration as a function of particle diameter (nanometers).

Bulk Composition of Ash Materials

The composition of the size fractions of ash materials collected using the multicyclone are summarized for the element of interest specifically the Na, K, Ca, and S. These elements produce very small particles upon combustion. Data is available in the appendix that includes the major elements determined. The trends for the ESP inlet are shown in **Figure 15** for sodium, potassium, calcium and sulfur, and in **Figure 16** for silicon, aluminum, magnesium and iron. The results show concentrating of the elements in the particles that are less than 10 μm in diameter.

Figure 17 shows the trend for the ESP inlet cyclone samples (cyclones 1, 3 and 4) for sodium, potassium, calcium and sulfur and **Figure 18** shows the trends for silicon, aluminum, magnesium and iron for the ESP inlet cyclone samples.

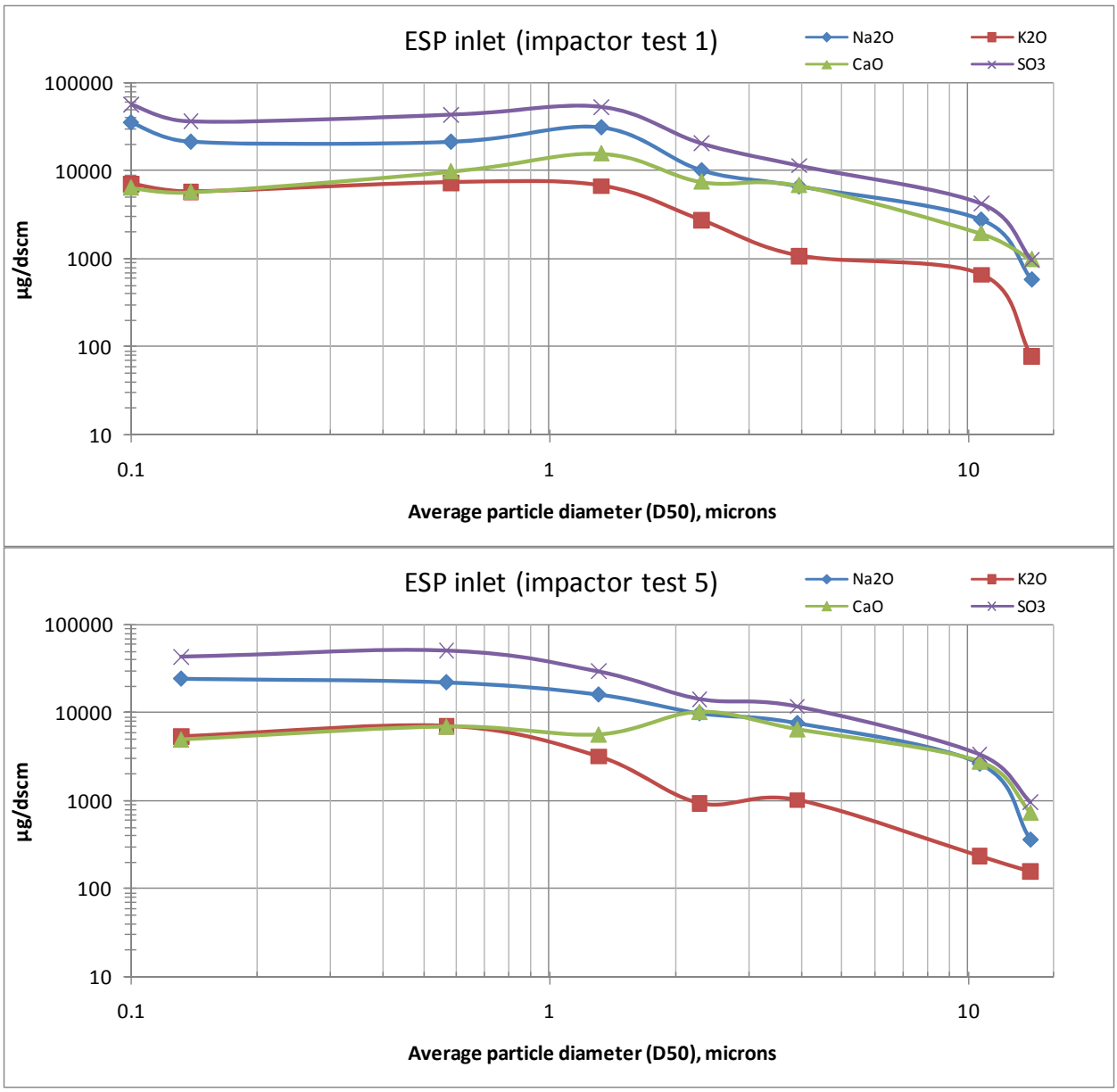


Figure 15. Sodium, potassium, calcium and sulfur concentrations as a function of average particle diameter for ESP inlet (impactor) samples.

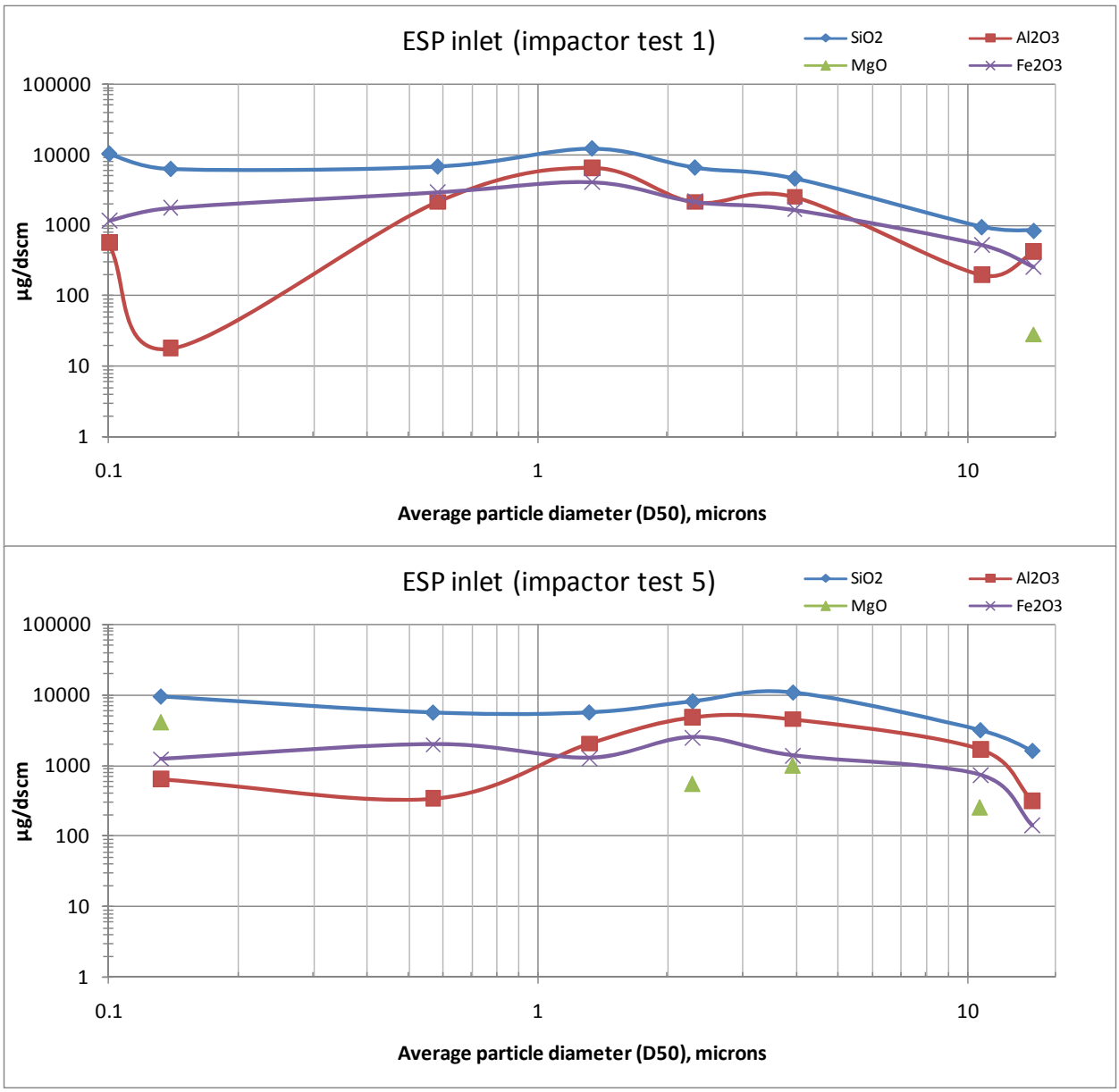


Figure 16. Silicon, aluminum, magnesium and iron concentrations as a function of average particle diameter for ESP inlet (impactor) samples.

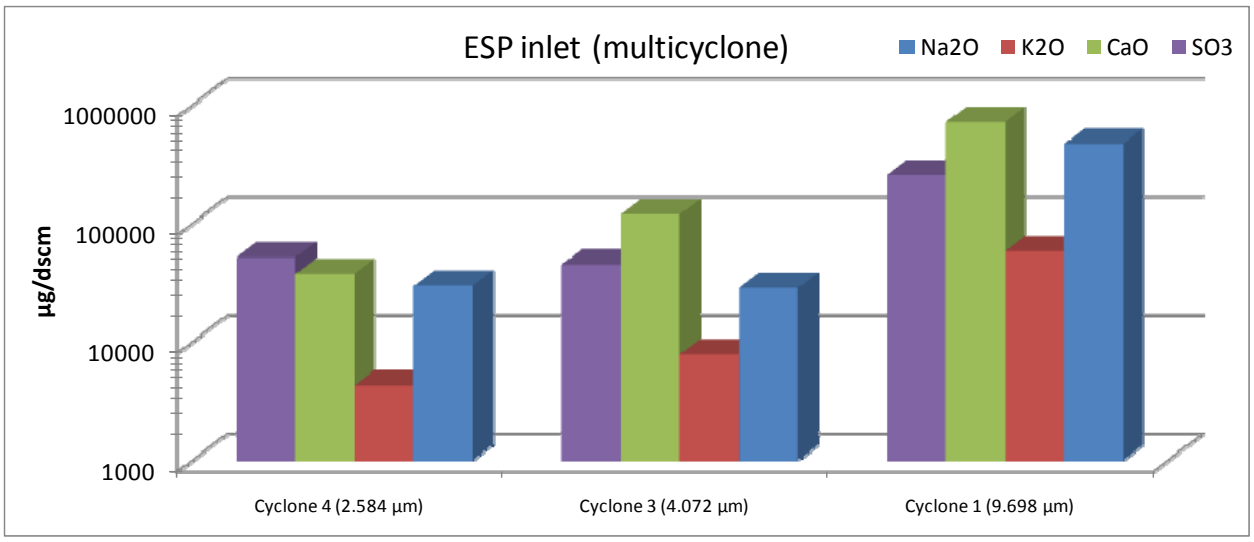


Figure 17. Sodium, potassium, calcium and sulfur concentrations for ESP inlet cyclone samples.

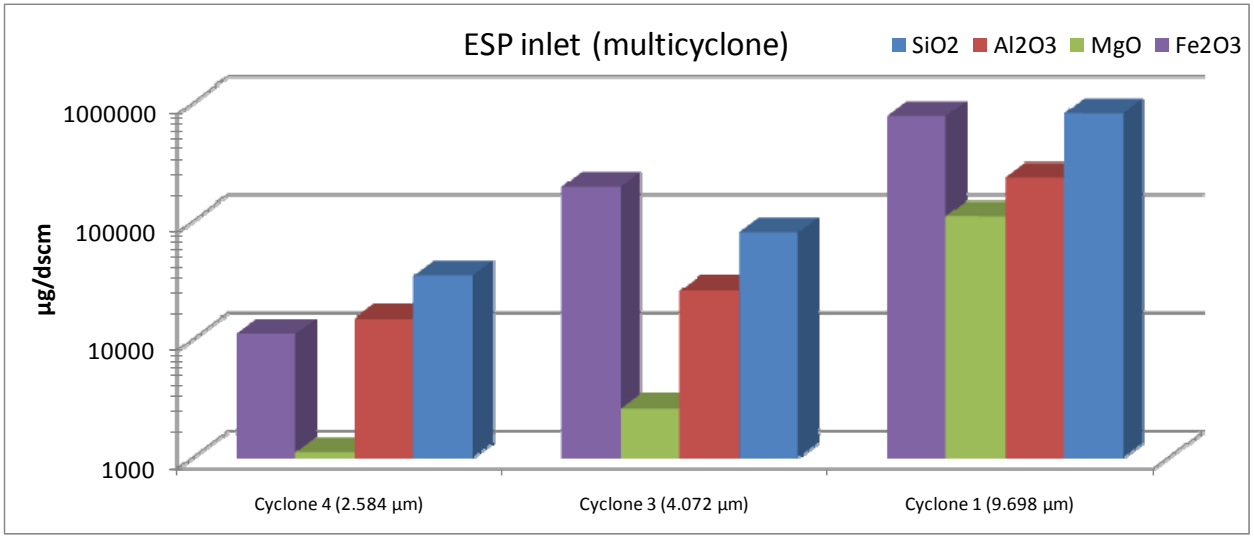


Figure 18. Silicon, aluminum, magnesium and iron concentrations for ESP inlet cyclone samples.

Analysis using digestion and inductively coupled plasma–mass spectrometry was performed to determine the concentrations of selected major elements (Ca, Fe, Mg, P, K, and Na) in the ash collected in the multicyclone stages. Table 9 lists the composition of selected elements based on the total sample collected in the multicyclone. Table 10 displays the fraction of each element, based on the total percent found in Table 9, by each cyclone stage. The largest concentrations of the selected elements were found in the first cyclone stage. The nozzle sample is material collected within the nozzle before the first multicyclone stage. This material is not size-fractionated.

The concentrations of the cyclone ash analyzed with ICP-MS cannot be compared well with the ash analyzed using SEM, as the ICP-MS samples were not analyzed for all major elements (including silicon, aluminum and sulfur).

Table 9. Percentage of each element in the total multicyclone sample (EERC).

Element	03/17/2009	03/19/2009
Calcium	13.36	12.15
Iron	6.85	6.54
Magnesium	3.27	3.14
Phosphorous	LBD*	LBD
Potassium	0.93	1.00
Sodium	6.63	6.26

* Level below detection (<400 ppm).

Table 10. Fractional percentage of each element by stage (EERC).

	03/17/2009				03/19/2009			
Element	Nozzle	Stage 1	Stage 3	Stage 4	Nozzle	Stage 1	Stage 3	Stage 4
Calcium	3.96	81.23	11.63	3.18	4.99	81.98	9.77	3.26
Iron	4.21	81.77	10.16	3.86	5.25	81.06	8.90	4.79
Magnesium	4.10	81.45	11.71	2.75	5.25	81.81	9.91	3.03
Phosphorous	LBD	LBD	LBD	LBD	LBD	LBD	LBD	LBD
Potassium	3.91	77.32	12.77	5.99	5.08	80.67	10.18	4.07
Sodium	4.21	77.80	12.82	5.17	5.67	80.59	9.88	3.85

The distribution of sodium, potassium, calcium and sulfur is illustrated in **Figure 19** and the distribution of silicon, aluminum, magnesium and iron is shown in **Figure 20**. The results show higher levels of sodium, potassium and sulfur at the one-micron level. The ESP was effective in removing larger-sized particles as well as some of the 0.1-µm particles. However, in the intermediate one-micron particle range the ESP is not as effective in removing the particles. This is a characteristic of all ESPs.

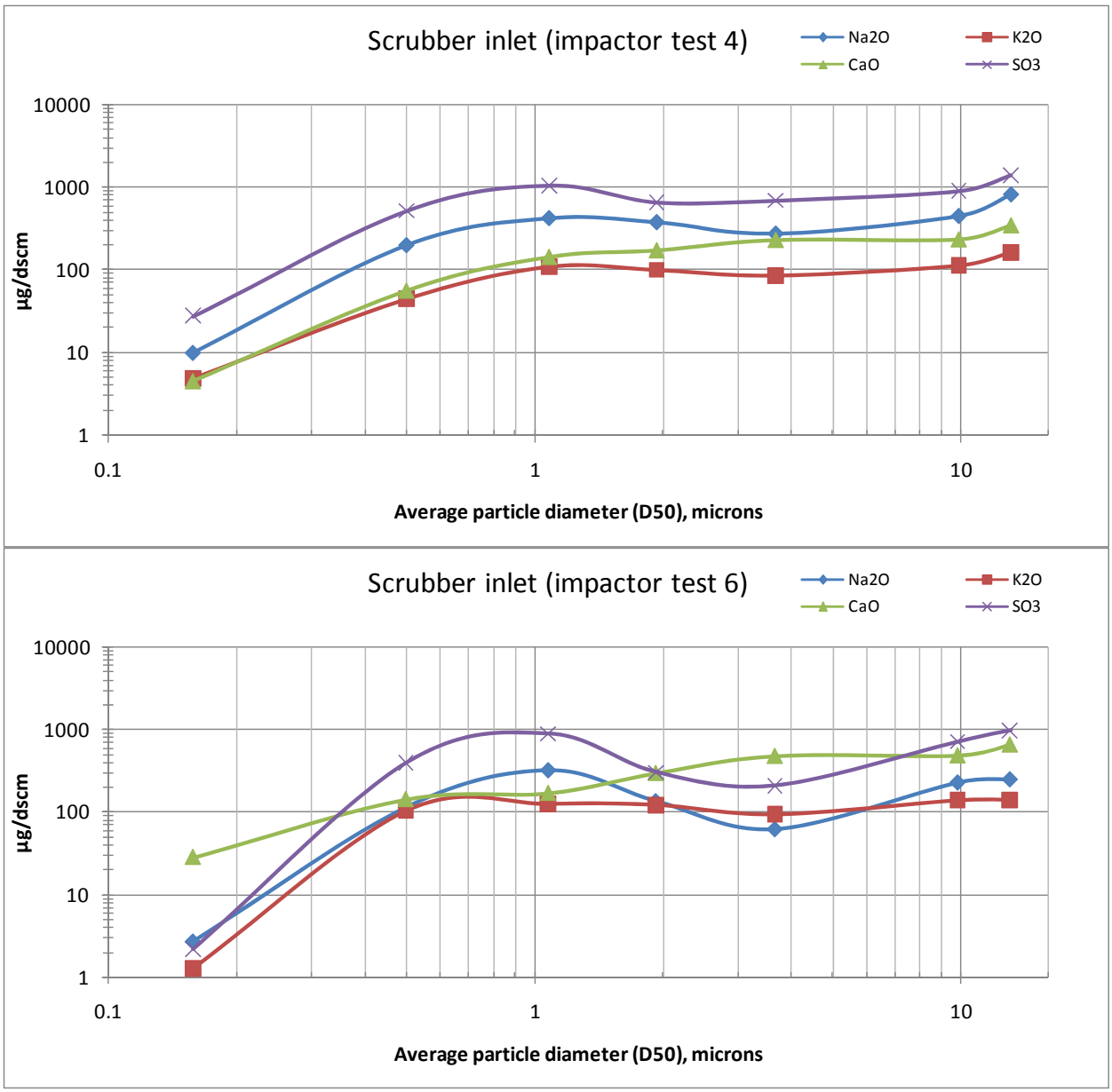


Figure 19. Sodium, potassium, calcium and sulfur concentrations as a function of average particle diameter in scrubber inlet samples.

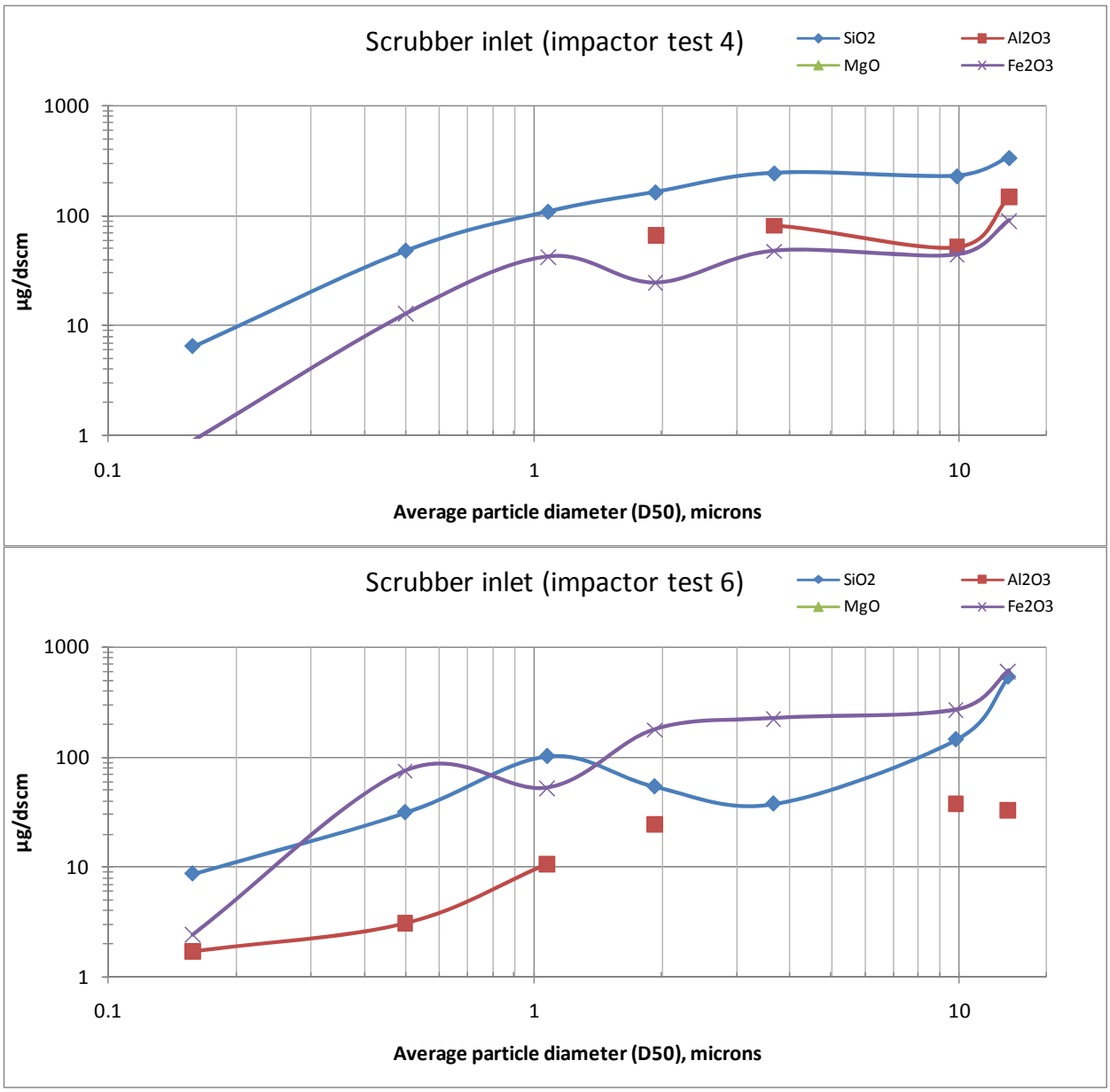


Figure 20. Silicon, aluminum, magnesium and iron concentrations as a function of average particle diameter in scrubber inlet samples.

The composition size distribution determined for sodium, potassium, calcium and sulfur downstream of the scrubber is illustrated in Figure 21. The results show a significant level of sodium and sulfur in the less than 1 µm size fraction. The DLPI sampling system provides very accurate sizing data in the submicron size range. The results show a maximum for sodium and sulfur at about 0.3 µm.

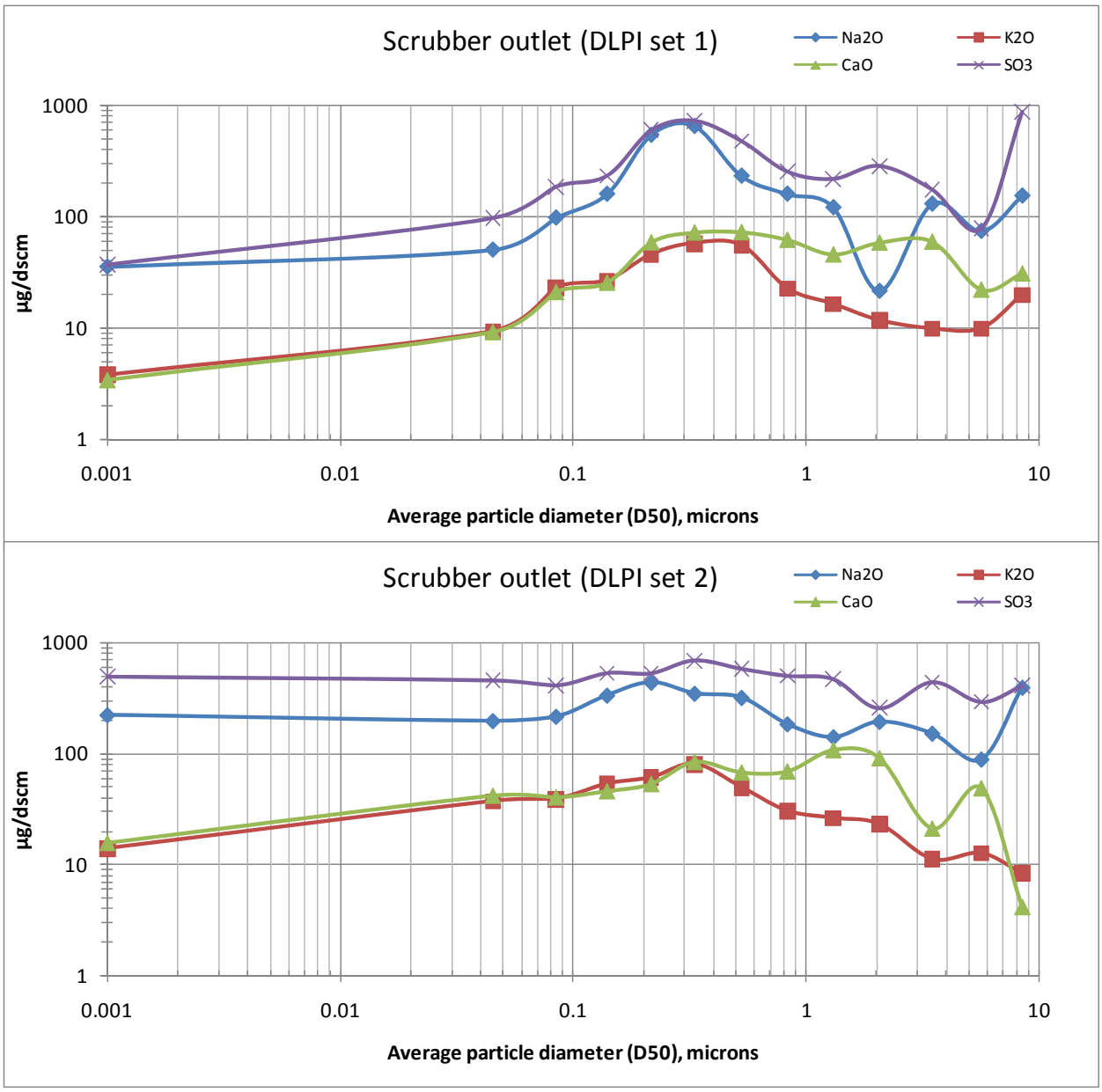


Figure 21. Sodium, potassium, calcium and sulfur concentrations as a function of average particle diameter in scrubber outlet samples.

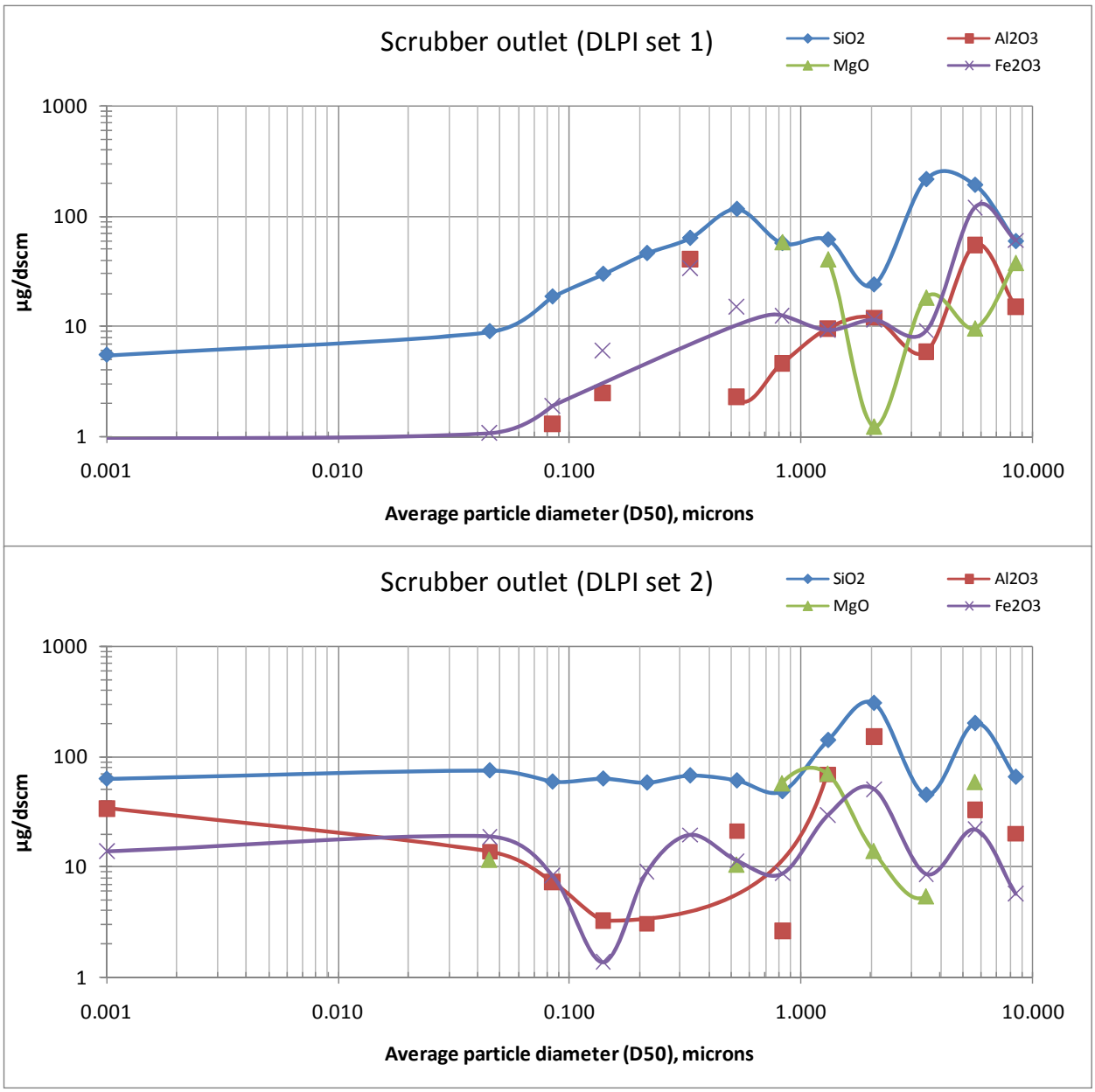


Figure 22. Silicon, aluminum, magnesium and iron concentrations as a function of average particle diameter in scrubber outlet samples.

Comparison of the mass of the particles in terms of composition is shown in **Figure 23**. The results show that sodium and potassium are reduced across the ESP. However, no reduction of sodium and potassium was observed across the scrubber. This is consistent with other scrubbers operating globally.

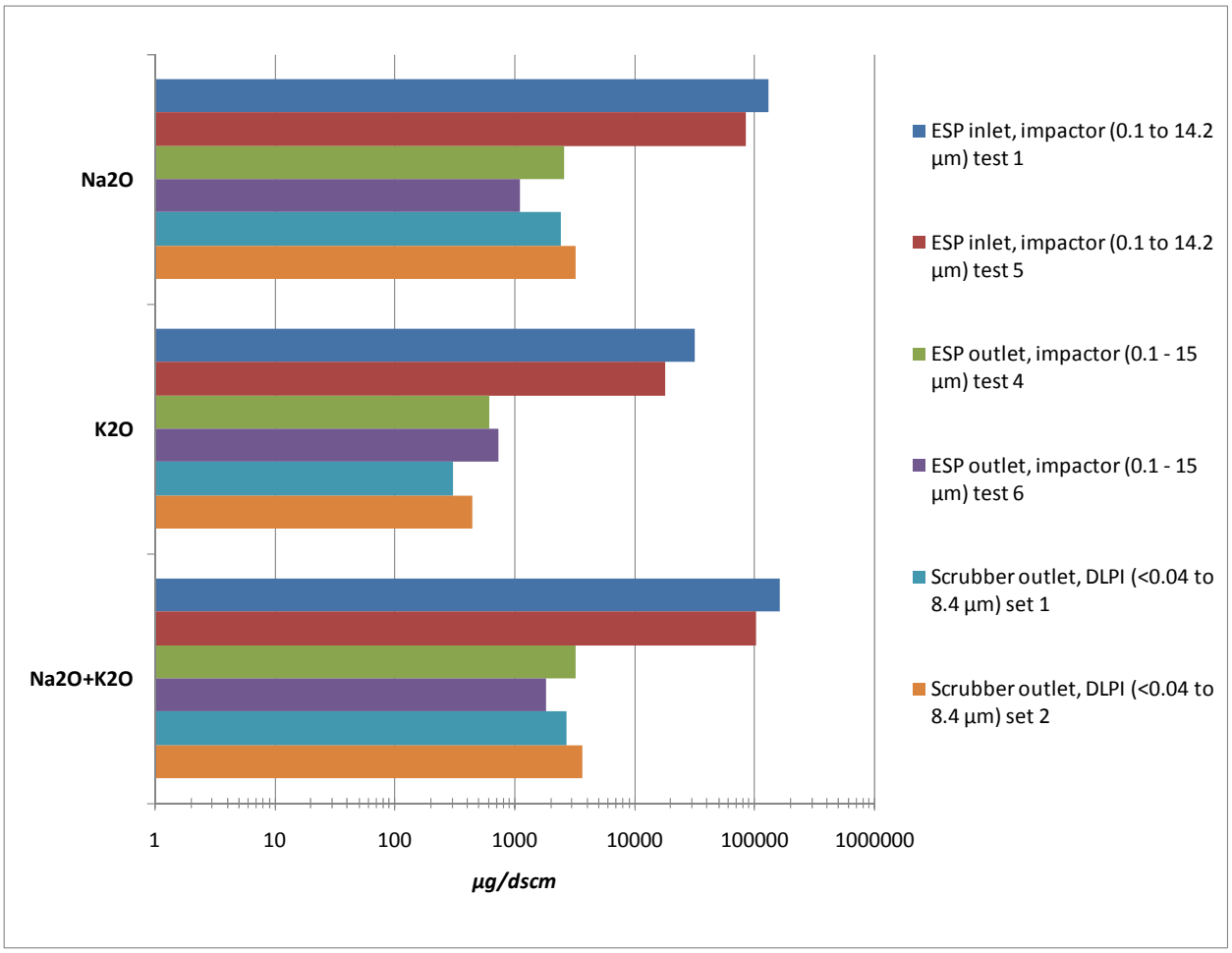


Figure 23. Mass of sodium and potassium oxide in the flue gas upstream and downstream of air pollution control devices at MRY.

SUMMARY AND CONCLUSIONS

Particulate sampling was conducted at Minnkota Power Cooperative's Milton R. Young plant to determine the particulate size and composition distribution of samples collected upstream of the ESP, upstream of the wet scrubber, and downstream of the wet scrubber. Emphasis was placed on determining the fate of sodium, potassium, and calcium since these elements can cause significant plugging and deposition problem.

During the testing, operating conditions of the plant were constant and there was no gas bypass. The coal fired during the testing remained relatively consistent. The as-received ash content ranged from 7.73 to 7.89%. Sodium oxide content of the ash ranged from 7.22 to 7.57% and the base-to-acid ratio decreased the last two days of testing (a result of a decrease in CaO content and an increase in SiO_2 and Al_2O_3 levels). Sampling upstream of the ESP and scrubber were conducted using a combination multicylones and impactors. The cyclones collected sized fractions of larger particles (greater than one to five microns) and the impactor collected the sub-micron particulate. Sampling downstream of the scrubber was conducted with a single cyclone followed by a 13-stage advanced impactor. In addition, the submicron particle number concentration was measured using a scanning mobility particle sizer (SMPS).

The results of the particulate mass information indicated a high loading at the ESP inlet of 4.96×10^6 µg/dscm, a scrubber inlet loading of 1.1×10^4 µg/dscm, and a scrubber outlet loading of 1.08×10^4 µg/dscm. These results show very little overall removal of the submicron particulate across the wet scrubber system. A significant fraction of the particulate was removed by the ESP, with a removal efficiency of 99.76%.

The size distribution of the particulate collected upstream of the ESP and upstream of the scrubber was multi-modal as summarized below:

- Upstream of the ESP there were at least three modes – a larger mode at 40 to 50 µm, a second mode at just under 10 µm, and third mode at about 1 µm. The larger particles are typically derived from mineral grains in the coal such as quartz, clays, and pyrite. The intermediate-sized particles are typically derived from small minerals and organically associated elements. The smaller mode (about one-micron and smaller) contains fine particles and condensed vapor phase species.
- Upstream of the scrubber there were two distinct modes – a larger mode between 8 to 10 µm and another mode centered at about 1 to 2 µm in diameter. The smaller mode is typically condensed vapor phase and small particles.
- Downstream of the scrubber, the primary mode centered at about 0.5 to 0.7 µm, and another possible mode occurred at 3 µm and larger.
- Particle number distributions were as follows:
    - Inlet to the ESP – between 1×10^7 to 10^8 particles per dry normal cubic centimeter (dncc);
    - Inlet to the scrubber is 10^5 particles/dncc;
    - Outlet of the scrubber 7×10^5 particles/dncc.
- Particle number distributions into the nanometer scale (1 µm = 1000 nm) was found to be as high as 10^5 particles/dncc.

Particle composition distributions of the particulate were determined for each of the major elements. The results were reported as μg/dscm of the element as illustrated in the Appendix and in the figures in the text.

- Upstream of the ESP the composition trends for sodium, potassium, calcium and sulfur showed greater concentrations of these elements in the particles that are smaller than 10 μm, with a significant increase in concentration in the flue gas at a particle size of less than 2 μm. There is another increase at 0.1 μm.
- Upstream of the scrubber the compositional trends for sodium, potassium, calcium and sulfur show higher levels at the 1 μm level. The ESP was effective in removing larger-sized particles, as well as some of the 0.1 μm particles. However, in the intermediate 1 μm particles, the ESP is not as effective in removing the particles.
- Downstream of the scrubber the composition size distribution determined for sodium, potassium, calcium and sulfur showed significant levels of sodium and sulfur in size fraction finer than 1 μm. The DLPI sampling system provides very accurate sizing data in the submicron size range. Other elements such as aluminum, silicon and iron show a significant depletion below 1 μm.

Comparison of the characteristics of the particles in terms of mass and composition indicate that, at the time of the testing, the total average mass of the particulate was about 10,800 μg/dscm. The particulate consisted mainly of sodium, potassium, and sulfur. The total quantity of sodium and potassium exiting was between 2000 to 3000 μg/dscm.

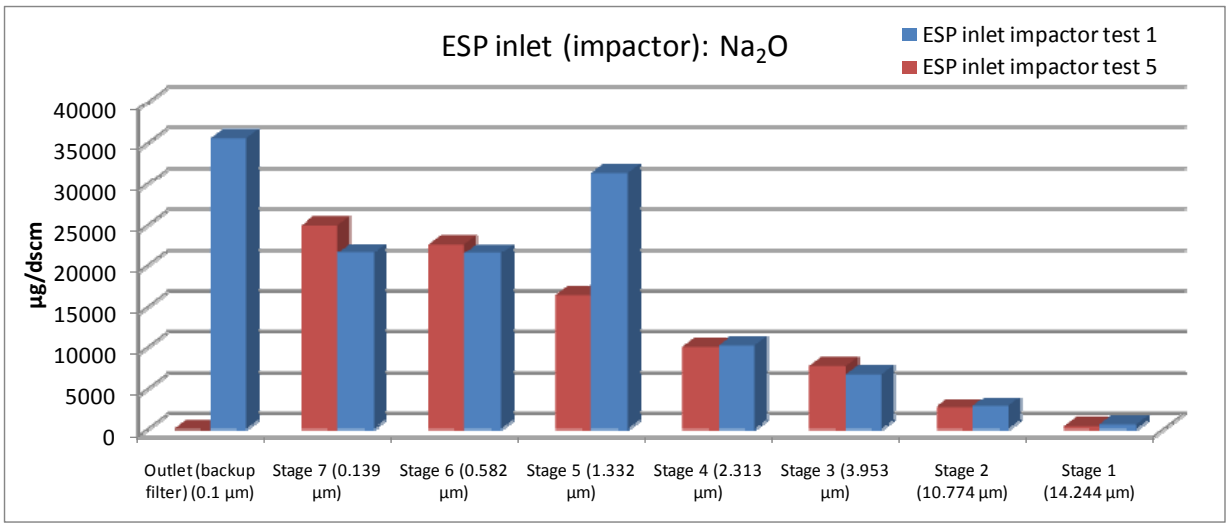


Figure A-1. Sodium concentration by sample stage (average diameter in microns).

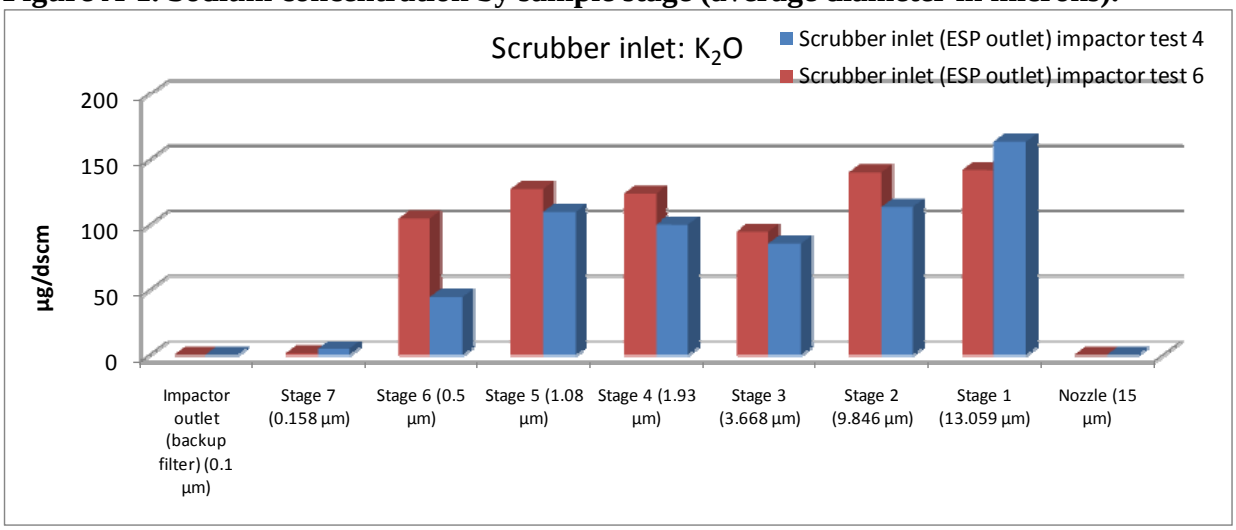


Figure A-2. Potassium concentration by sample stage (average diameter in microns).

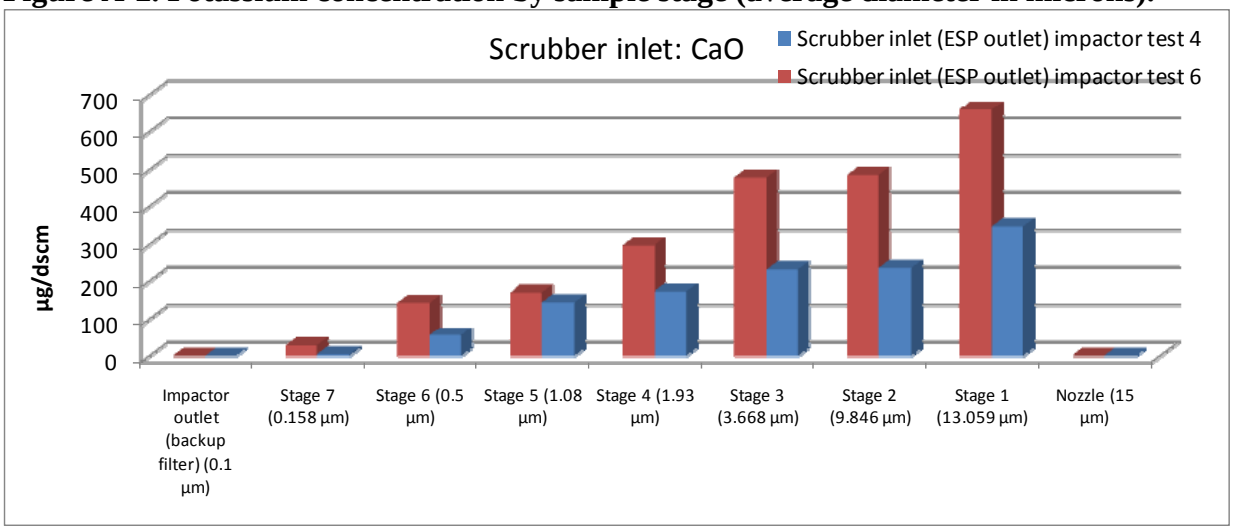


Figure A-3. Calcium concentration by sample stage (average diameter in microns).

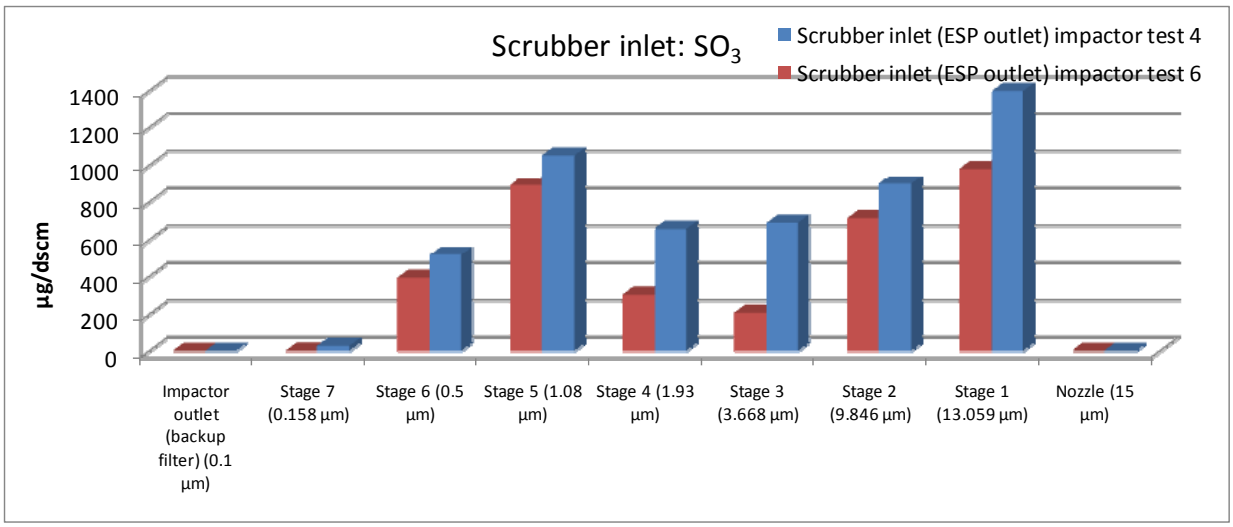


Figure A-4. Sulfur concentration by sample stage (average diameter in microns).

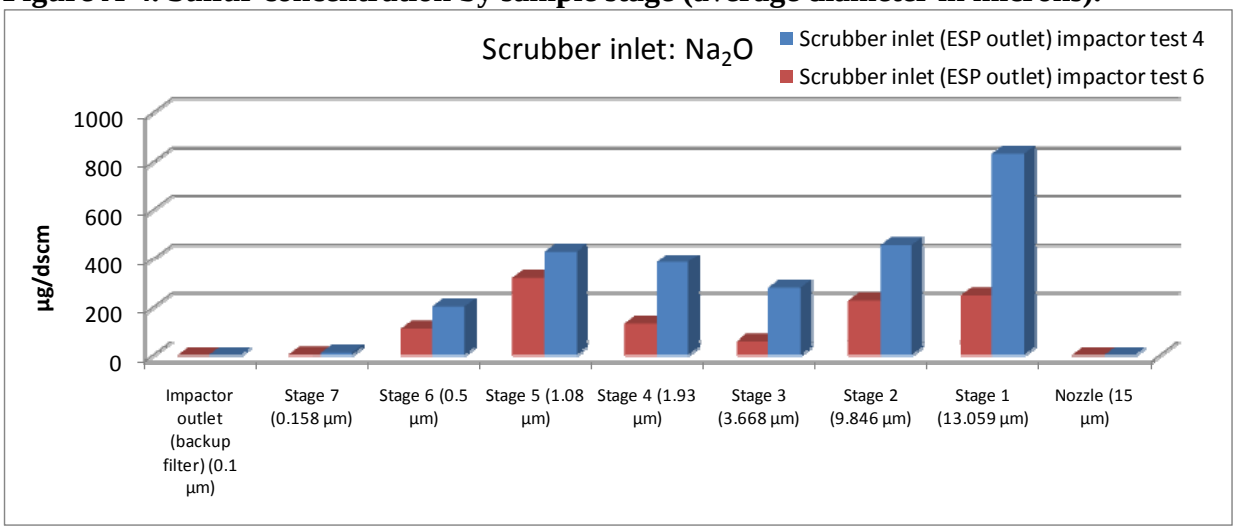


Figure A-5. Sodium concentration by sample stage (average diameter in microns).

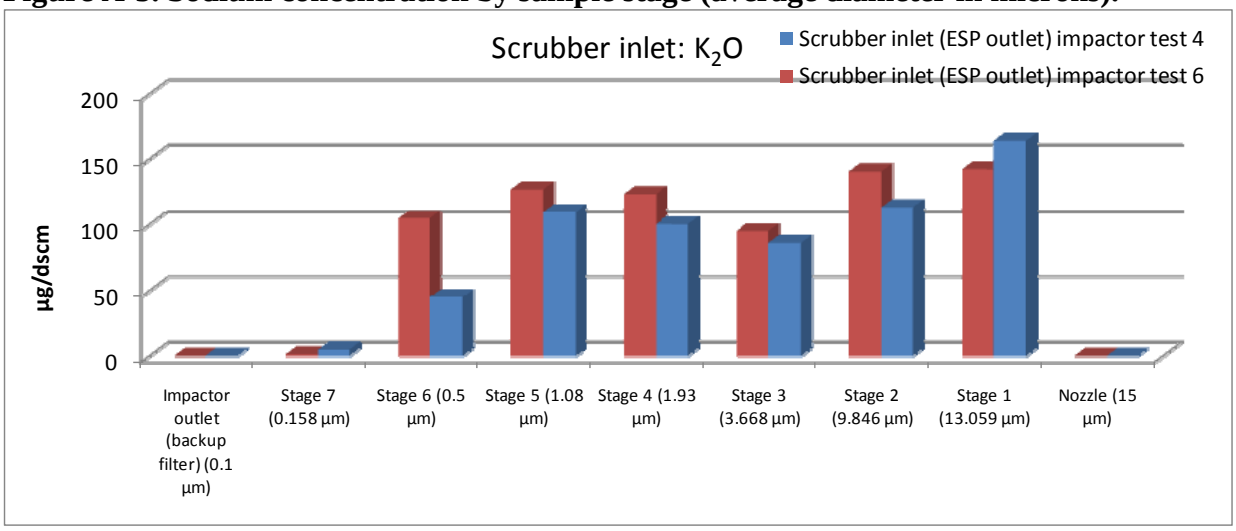


Figure A-6. Potassium concentration by sample stage (average diameter in microns).

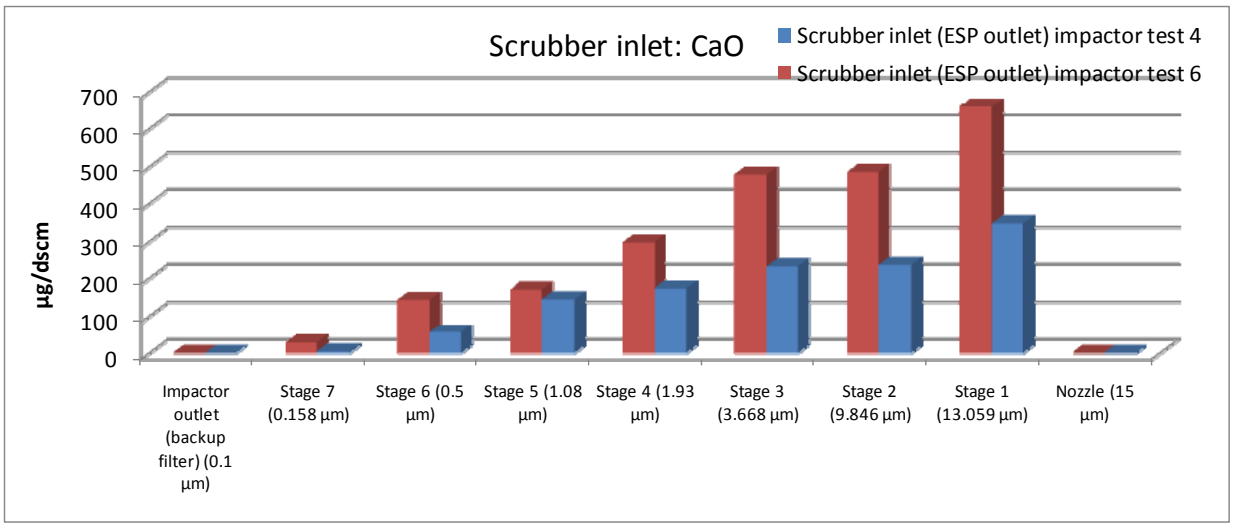


Figure A-7. Calcium concentration by sample stage (average diameter in microns).

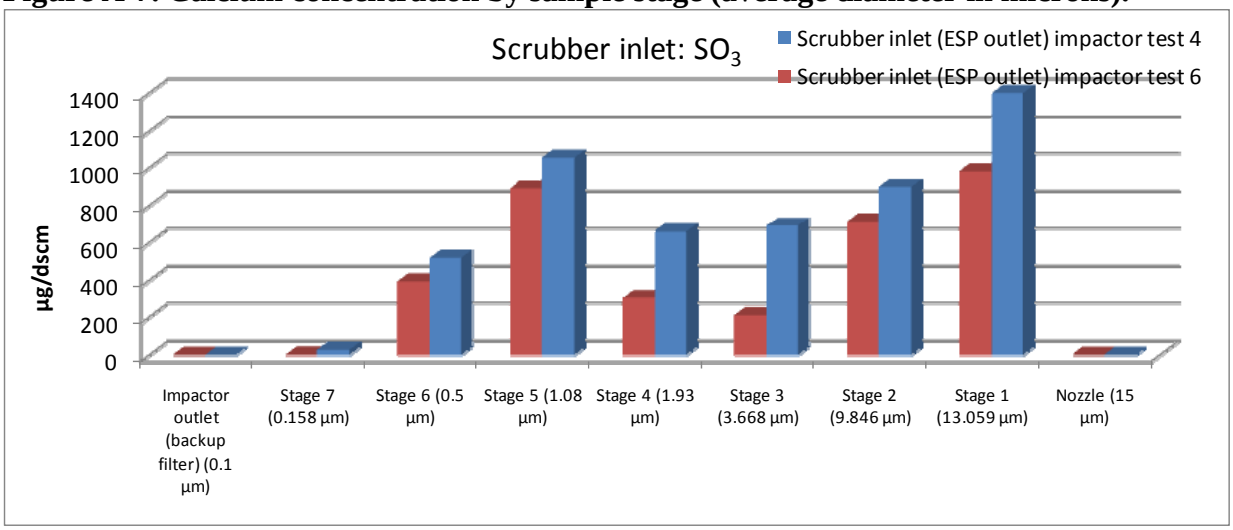


Figure A-8. Sulfur concentration by sample stage (average diameter in microns).

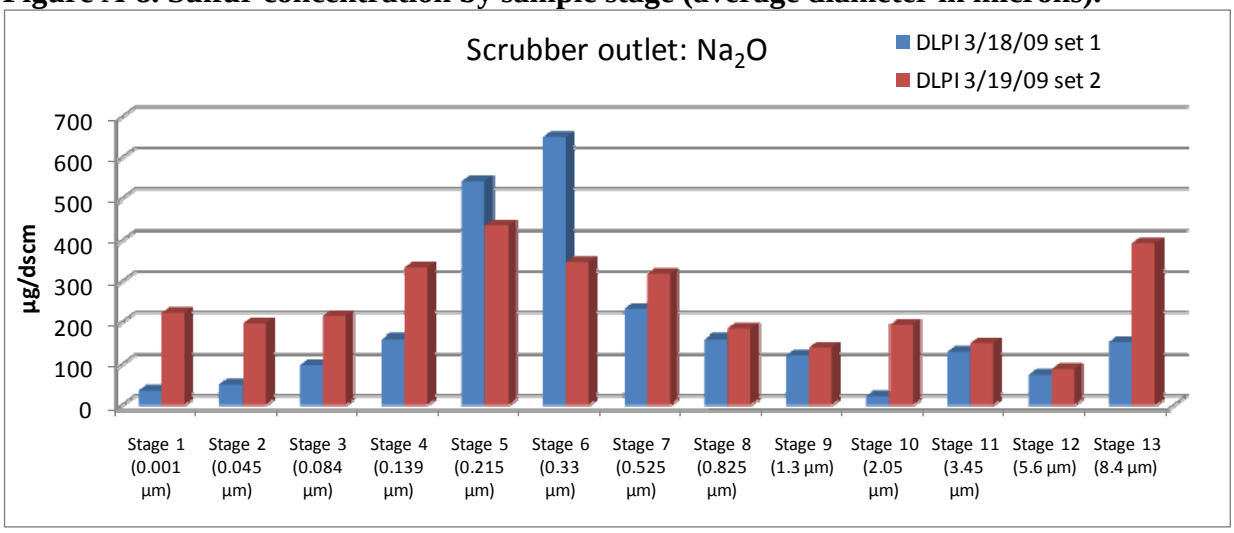


Figure A-9. Sodium concentration by sample stage (average diameter in microns).

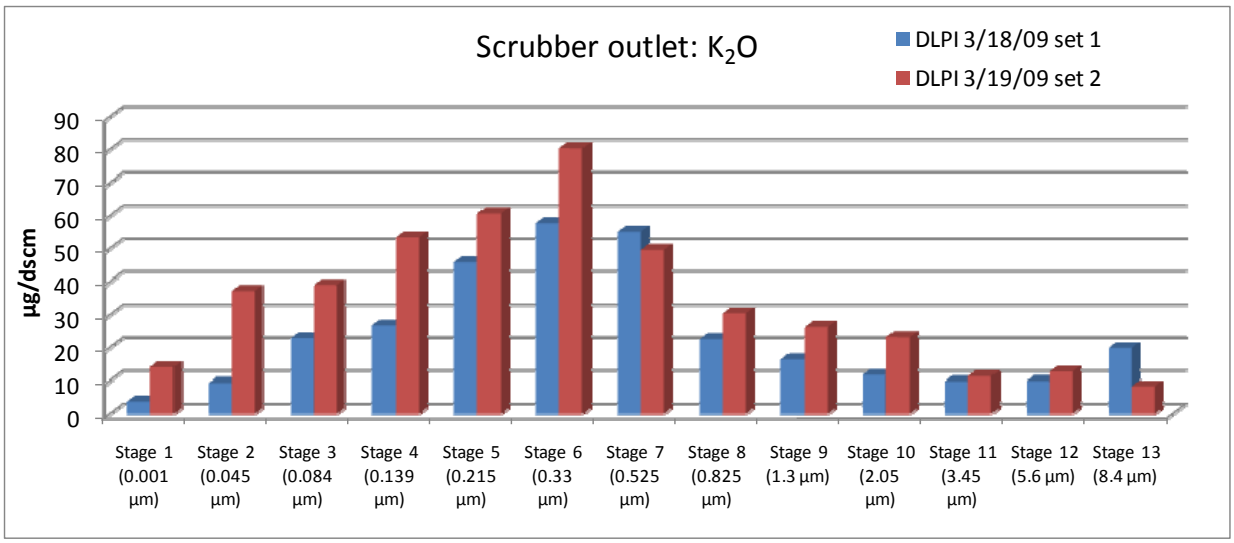


Figure A-10. Potassium concentration by sample stage (average diameter in microns).

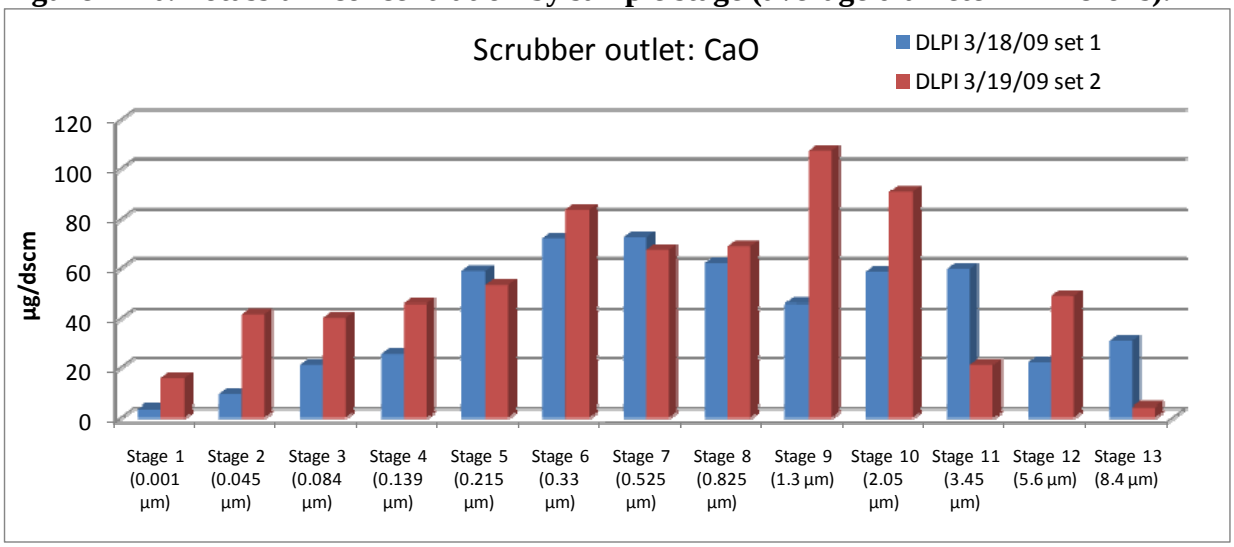


Figure A-11. Calcium concentration by sample stage (average diameter in microns).

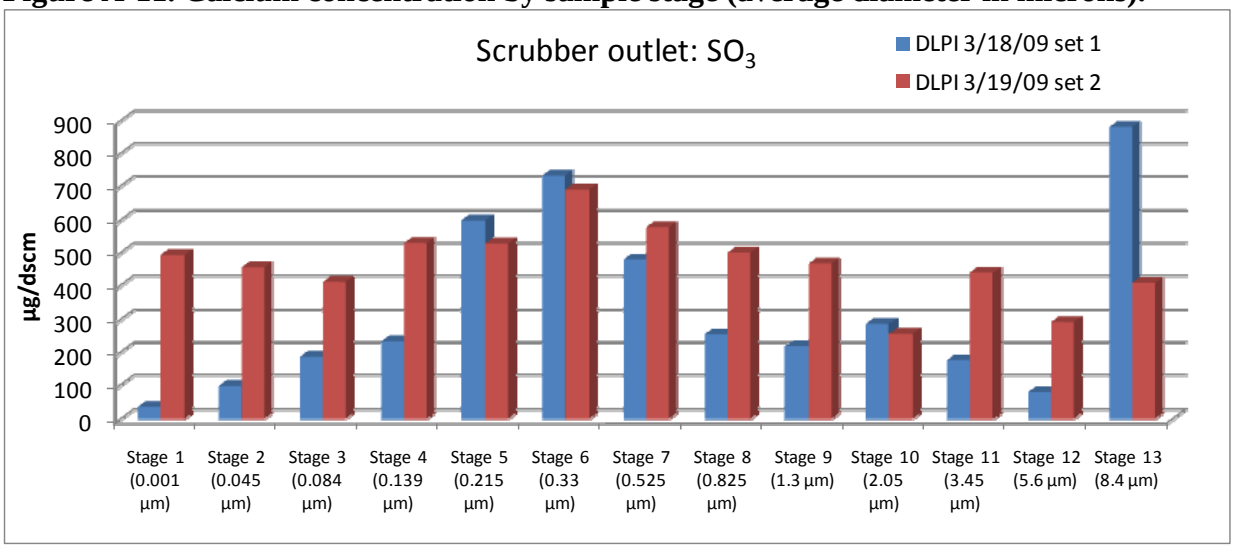


Figure A-12. Sulfur concentration by sample stage (average diameter in microns).

Temperature

The temperature in the field during this test was approximately 24°F. This made it very difficult for the equipment to start and warm up to normal operation conditions, especially the CPC. With the help of a fish tent, carpets, and small blow heaters, the CPC was brought to normal operating temperature. Because of the cold conditions, there was a significant condensation issue in the lines that fed the SMPS system. Although this problem was reasonably resolved for all lines from the probe end to the EC by applying heat/thermal tapes, the lines connecting the EC and CPC also had a buildup of condensed fluid to the extent that they had to be drained at one point to help stabilize the flow via the CPC pump.

Wind

Another challenge faced in the field was the high winds of more than 20 mph. With the scrubber outlet location being about 105 feet above the ground, such windy conditions constantly shook the grid and the equipment; thereby introducing turbulence to the flow through the CPC pump.

Pore Flue Gas Pressure

A more serious problem was the lack of adequate positive pressure from the sampling port to supply enough flue gas through lines into the SMPS system. This resulted in very low counts observed in many data sets. Although the sampling port at the scrubber outlet is at positive pressure, it probably was not high enough to feed enough flue gas through the small nozzle of the sampling probe to the SMPS system.

Milton R. Young Unit 2

MRY Unit 2 is a Babcock & Wilcox (B&W) Carolina-type radiant boiler designed to burn high-moisture, high-slagging/fouling North Dakota lignite. Nominally rated at 3,050,000 lb/hr, this unit is a cyclone-fired, balanced-draft, pump-assisted circulation boiler. The unit began commercial operation in May 1977 and is base-loaded at 470 MW gross. The unit is equipped with a cold-side ESP for particulate control and a wet FGD unit for SO_2 control. The cold-side ESP has a specific collection area (SCA) of 375 ft^2/1000 acfm. The wet FGD for SO_2 control utilizes alkaline ash and lime. The MRY Station fires North Dakota lignite coal from the Kinneman Creek and Hagel Seams at the Center Mine.

Form of Sodium in Center Lignite

Sodium is associated with the organic matrix in Center lignite. That means the sodium is atomically dispersed in the organic matrix. The sodium is associated with a carboxylic acid groups (ion exchange sites). The carboxylic acid groups act as bonding sites for various elements such as Ba, Ca, Mg, and Sr along with minor amounts of K. Figure C-1 illustrates the bonding of sodium to the organic fraction of the coal and the association of other coal impurities.

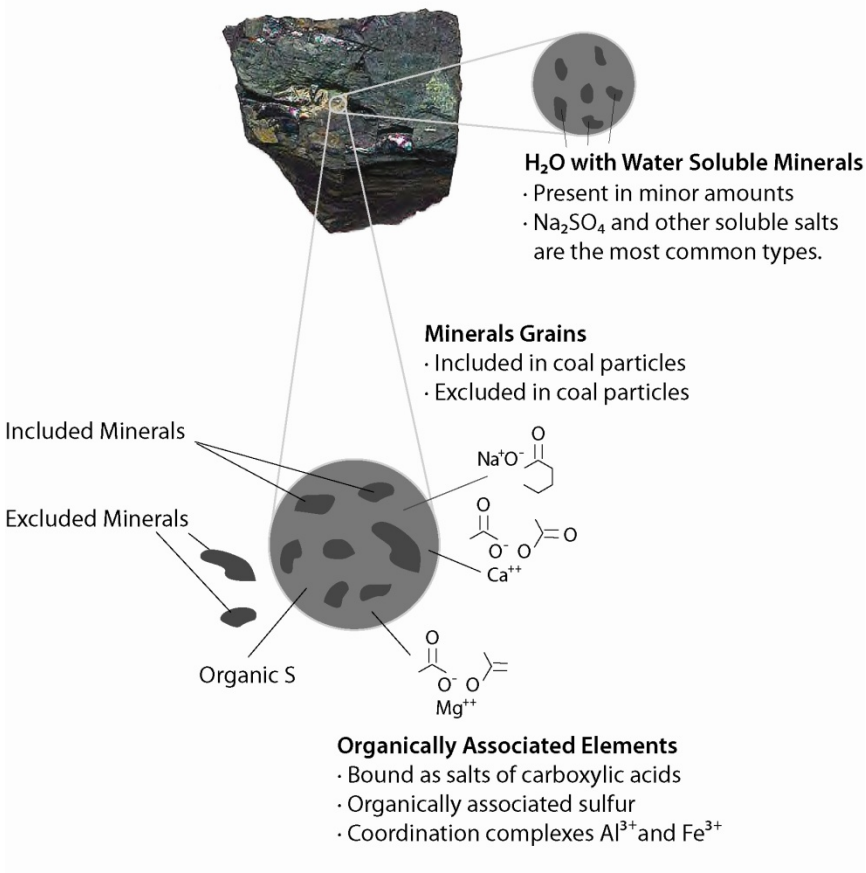


Figure C-1. Form of sodium in coal (Benson and Laumb, 2008).

Vaporization of sodium in PC and cyclone-fired systems

Sodium is a volatile element and will be transformed into a gas upon combustion. The vaporization of sodium during the combustion of lignite is a very well known fact that has been examined by numerous investigators; include work conducted by MIT, CalTech, Sandia National Laboratory, National Energy Technology Laboratory, University of Utah, and others. For example, research conducted by Senior and others (2000) reported that relative to other coals, North Dakota lignite produced more vaporized ash. The actual amount vaporized for ND lignite is double the level vaporized as compared to subbituminous and lignite coals from Montana as illustrated in Figure C-2. Work conducted at the MRY plant related to the vaporization of sodium from a cyclone fired systems is illustrated in Figure C-3. The results show over two thirds of the sodium is not retained in the slag and is vaporized.

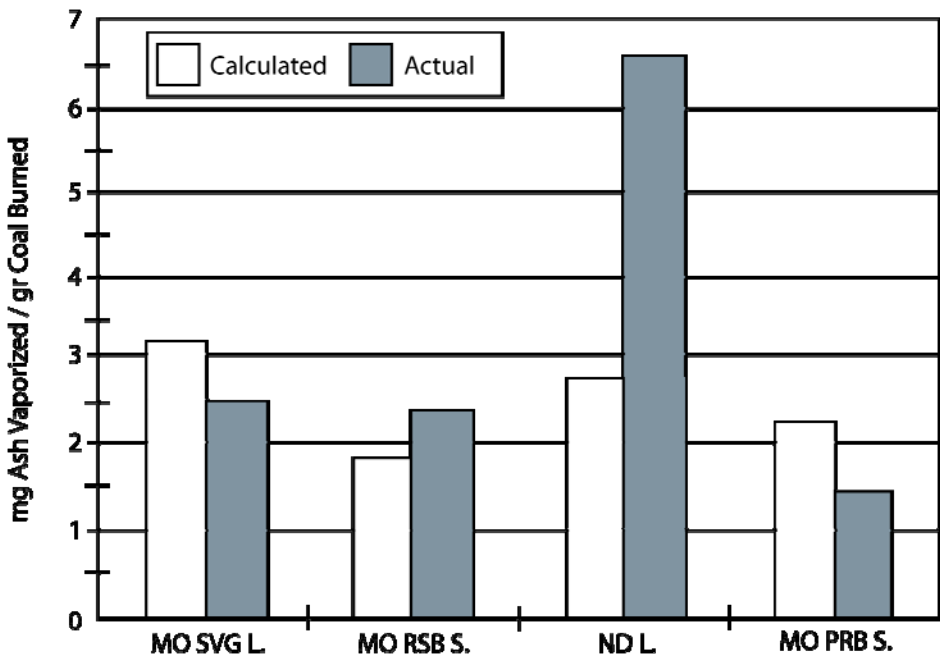


Figure C-2. Ash vaporized during combustion of lignite and subbituminous coals (Senior and others, 2000).

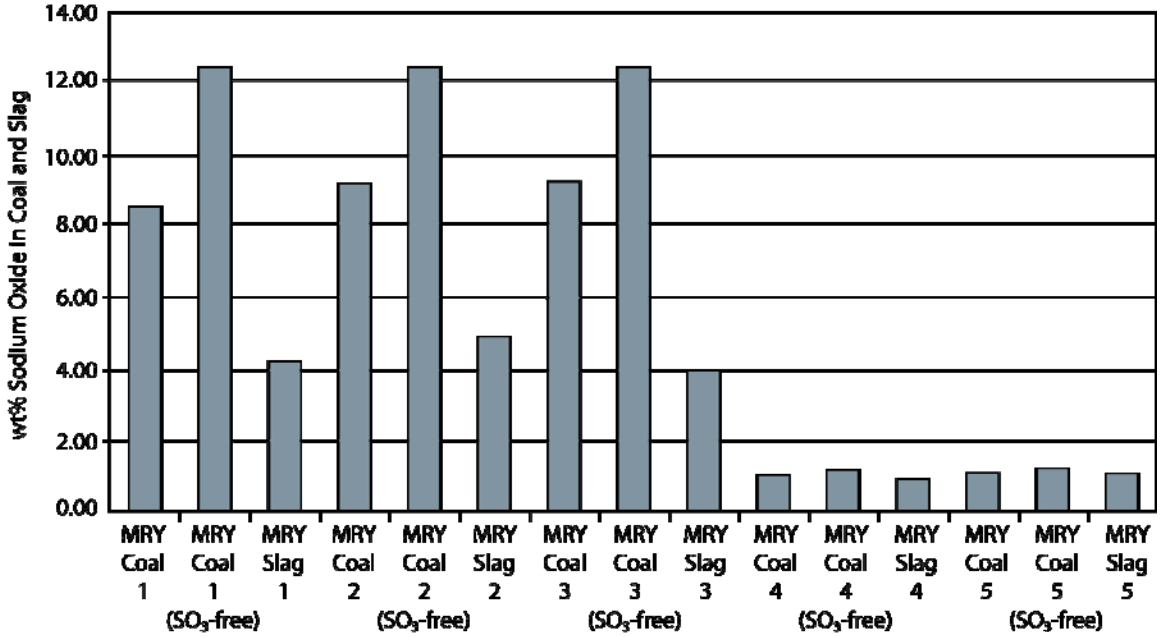


Figure C-3. Comparison of sodium levels in Center lignite coal and slag samples.

Condensation of vaporized species to form aerosols

EPA has evaluated the literature on particle formation during combustion and from other sources and incorporated it into an educational module that can be found on the following website (http://www.epa.gov/apti/bces/module3/formation/formate.htm). The classification of particle types shown by EPA is illustrated in Figure C-4. The EPA classification is consistent with the review conducted by Lighty and others (2000). Vaporized species can condense heterogeneously on surface of other entrained coarse ash particle and can condense homogeneously to form the fine and ultrafine particles. The distribution of particles depicted in Figure C-4 is shown on a frequency percent of particles by mass basis. The particle number versus size is also important and a comparison of the number of particles and particle size is summarized in Table C-1. The number of aerosol particles is significant. These particles have high surface areas and are very reactive.

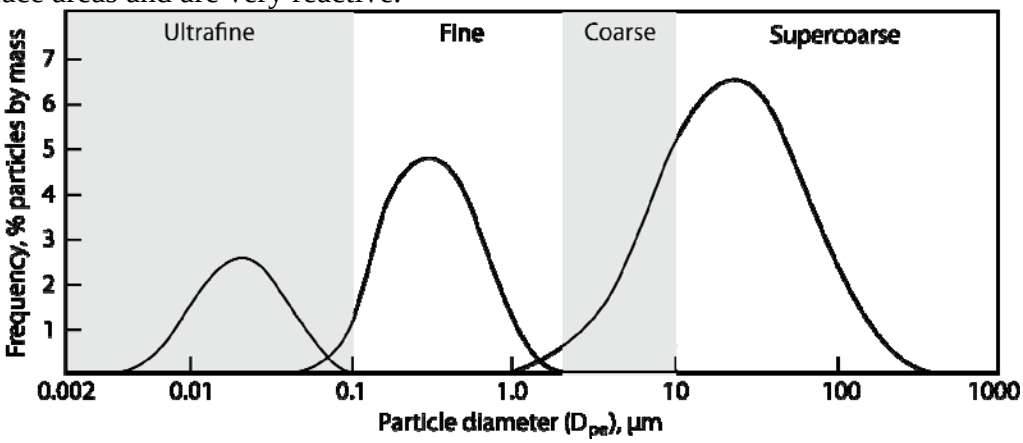


Figure C-4. Particle size categories used to classify particles (http://www.epa.gov/apti/bces/module3/category/category.htm)

Table C-1. Particle size, number of particles, and surface area[1] (http://www.epa.gov/apti/bces/module3/category/category.htm)

Total Mass	Diameter of Particles (µm)	Number of Particles (Approx. in millions)	Total Surface Area (cm^2)	Total Surface Area (m^2)
1.0 gm	1,000	1.002	60	1.006
	100	2	600	0.06
	10	2,000	6 000	0.6
	1	2,000,000	60,000	6
	0.1	2,000,000,000	600,000	60

(1) Based on density of 1.0 gm/cm^3

Figure C-5 provides a comparison of the mass distribution and particle number distribution. As the particle size decreases the number of particles in the size fraction increases. In addition, as illustrated in Table C-1, the surface area increases significantly with decreasing particle resulting in the opportunity for reactive gases such as sulfur oxides to react forming sticky phases that bond particles together.

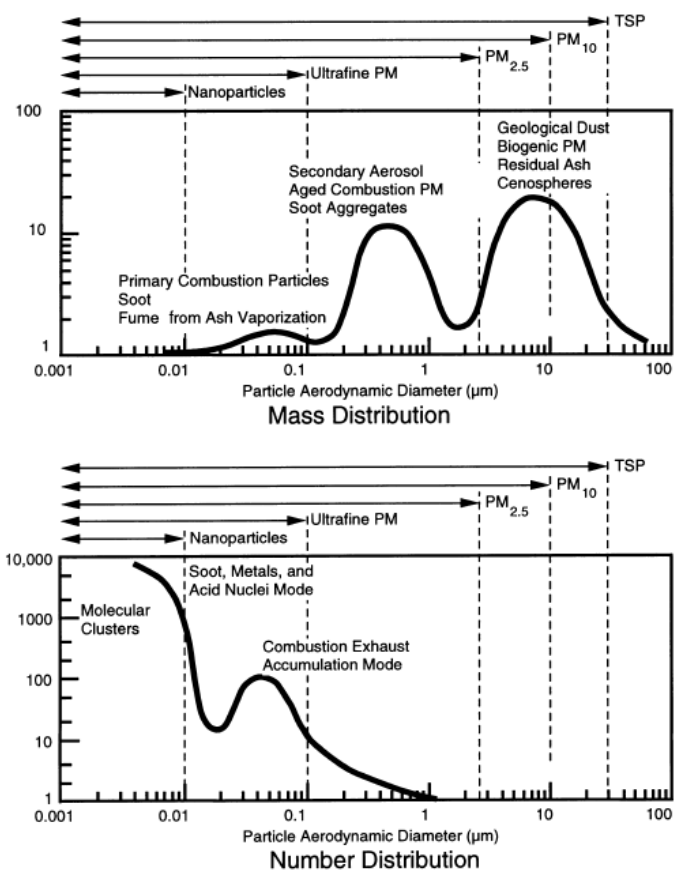


Figure C-5. Comparison of mass distribution and particle number distribution for combustion derived particles and aerosols (Lighty and others, 2000).

Particle size distributions for fly ash collected upstream and downstream of an ESP are illustrated in Figure C-6. This work was conducted by Markowski and others (2000) specifically aimed at characterizing the submicron aerosol mode of fly ash formation.

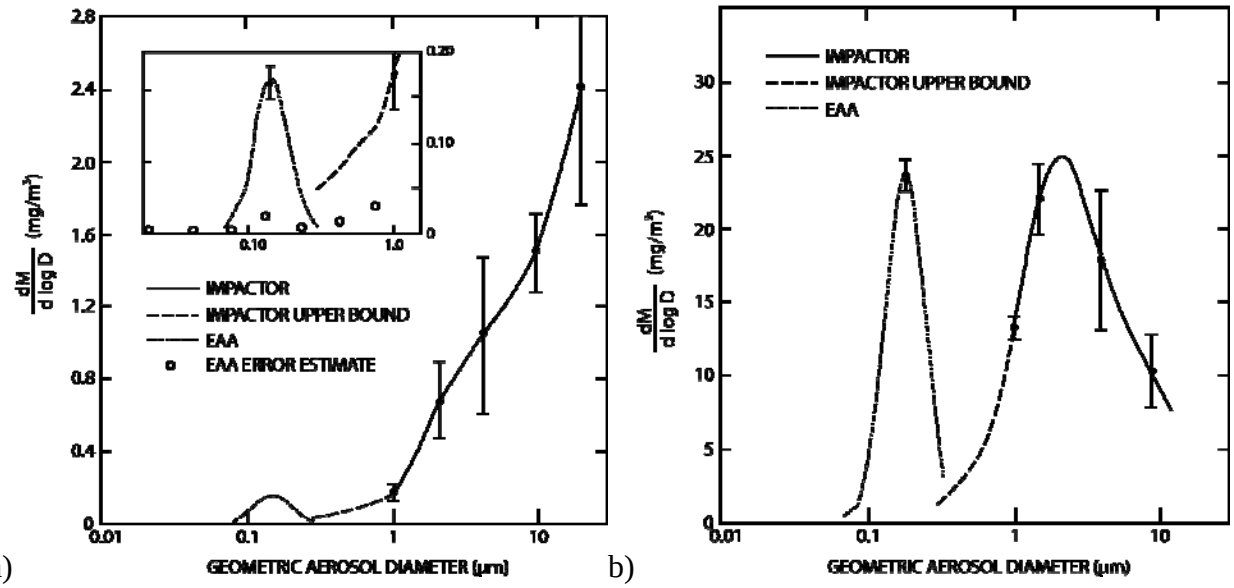


Figure C-6. Typical differential mass distributions of particulate collected a) upstream and b) downstream of an ESP (Markowski and others, 2000).

Fly ash produced upon the combustion of high sodium lignites in a pulverized coal (PC) fired system shows significant enrichment of sodium in the smaller size fractions as shown in Figure C-7. This figure illustrates the increase in the sodium content in the finer size fractions of ash as a result of firing high sodium lignite. The sodium and sulfur content of the less that 3 micrometer size fraction of the sampling train approached 20% Na_2O, and 25% SO_3. The form of the sodium is likely sodium oxide and sulfate.

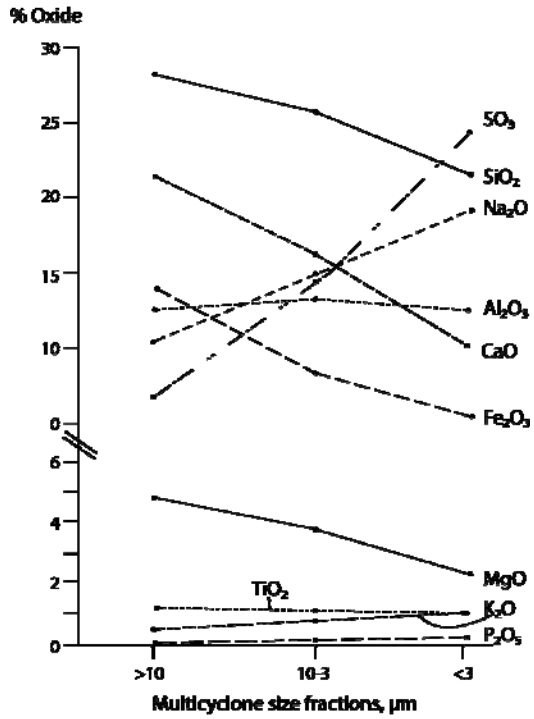


Figure C-7. Composition distribution of ash particles during combustion of North Dakota Lignite (Benson and others, 1984).

Electrostatic precipitator collection efficiency

The classical curve for ESP particle collection efficiency is shown in Figure C-8. This curve is typical of well behaved ash materials that do not present significant problems in collection. The collection efficiency is very good for particles greater than 5 to 10µm and the collection efficiency decreases with decreasing particles size with minimum collection efficiency between 0.2 to 2 µm in diameter. The collection efficiencies vary significantly because of particle size and composition.

Low collection efficiency for difficult to collect particles is between 0.1 to 1 µm in particle diameter. Figure C-9 provides an illustration of the range of collection efficiencies. Based on EPA education modules, no air pollution control device shows high collection efficiency in this range (0.1 to 1.0 µm) due to inherent limitations of the collection devices and particle characteristics (http://www.epa.gov/apti/bces/module3/collect/collect.htm). The following mechanisms of particle capture are impacted by the size of the particles:

- Inertial impaction and interception
- Brownian diffusion
- Gravitational settling
- Electrostatic attraction
- Thermophoresis
- Diffusiophoresis

The EPA (http://www.epa.gov/apti/bces/module3/collect/collect.htm) has indicated that based on a number of studies of actual "*sources stationary sources generating high*

concentrations of particles in the 0.1 to 0.5 micrometer range may be an especially challenging control problem. … The gap is most noticeable in wet scrubbers and electrostatic precipitators." A generalized plot showing the range of collection efficiencies is shown in Figure C-9. Overlaid on the diagram is the mass size distribution of particles collected downstream of the ESP wet FGD at the MRY plant (Markowski and others, 1983). This shows that ash produced in the MRY plant have a particle size that can pass through the scrubber and that these particles are rich in sodium as shown in Figure C-7.

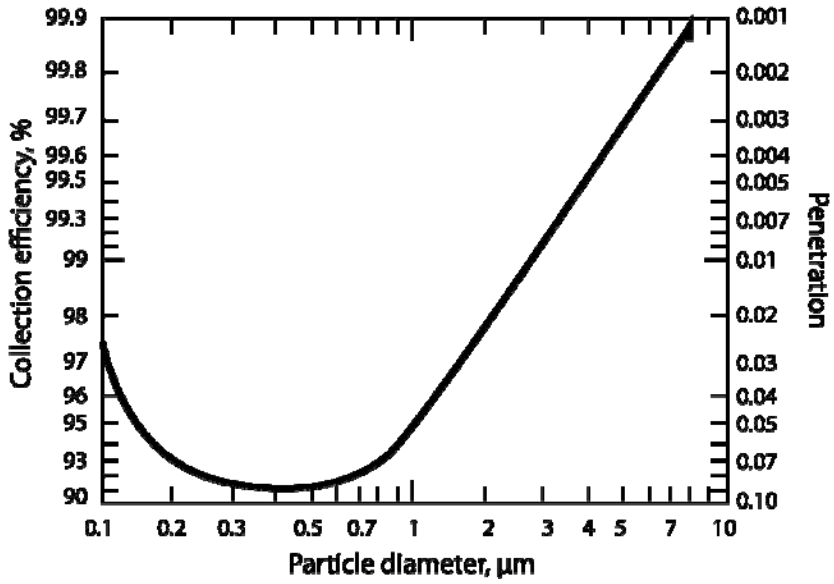


Figure C-8. Typical ESP Collection efficiency curve for removal of particulate from gas streams (http://www.epa.gov/apti/bces/module3/collect/collect.htm).

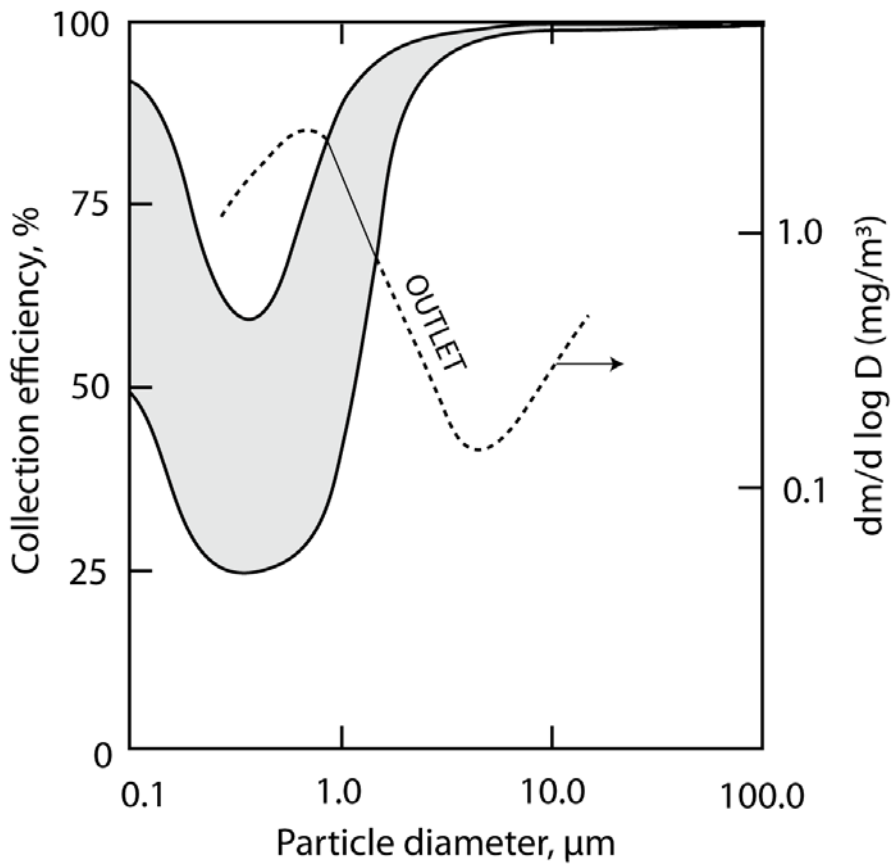


Figure C-9. Particulate control efficiency for difficult to control particulate combined with the mass distribution of particulate collected downstream of the scrubber at MRY (Markowski and others, 1983, http://www.epa.gov/apti/bces/module3/collect/collect.htm)

Field Experience and Testing

As indicated by EPA (Woodward, 1998), scrubbers do not effectively remove particulate less than 1µm in diameter. There is significant evidence that sodium-rich aerosols penetrate ESPs as well as scrubbers at full-scale power plants when firing high-alkali-containing fuels. An example is a biomass fired system using a tower type scrubber where the removal efficiency of the smaller size fraction of ash is low, as shown in Figure C-10 (Ohlström and others, 2006).

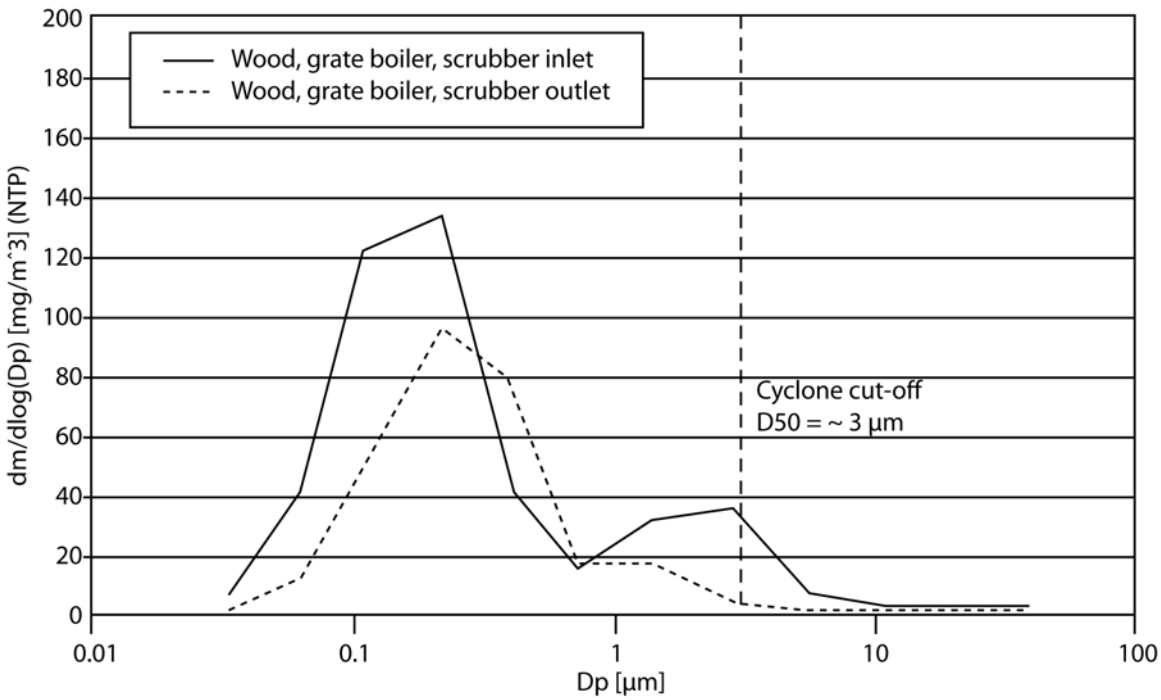


Figure C-10. Removal of fine aerosols using a scrubber on a wood fired combustor (Ohlström and others, 2006).

Minnesota Power's Boswell Energy Station found that when it fired high-sodium, lower-ash northern Powder River Basin subbituminous coal (7% Na_2O in the ash), it experienced increases in opacity. Hurley and Katrinak (1992) conducted a field-testing project on Unit No. 4, a pulverized coal-fired boiler equipped with a venturi wet scrubber, to better understand the reasons for the opacity problems. During the field testing, sampling of the coals, flue gases, and scrubber materials was conducted. The particulate in flue gases downstream of the scrubber was aerodynamically classified using multicyclone followed by an impactor and a Nucleopore filter. The sized fractions were weighed and analyzed to determine the abundance and composition of the submicron-sized fractions. The mass loadings in the various size bins are plotted in Figure C-11, showing that the scrubber is quite effective in removing the larger particles. However, the scrubber is not very effective in removing the aerosols less than 1 micrometer in diameter for both the blended coal and the high sodium coal (Coal A).

The results of the study indicated that the particulate collected downstream of the scrubber was coal-related and caused by the high sodium content of the coals. Vapor-phase sodium condenses in the boiler's convective pass to form fine sodium-rich aerosols or other Na species that later react with ash particles. Pure Na_2SO_4 particles are too small to be removed by such scrubbing. Figure C-12 shows the spikes of the ash material collected on Stage 10 of the impactor. This impactor accumulation represents particles of less than 0.7 to 2.5 micrometer size fraction of the submicron aerosol. The spikes are made up of submicron particulate matter, and the chemical analyses of the spikes and ash particles collected on the Nucleopore filters downstream of the impactor plates are shown in Table C-4. Both samples are dominated by sodium and sulfur that are likely in the form of sodium sulfate. These sulfate materials exhibit highly cohesive tendencies.

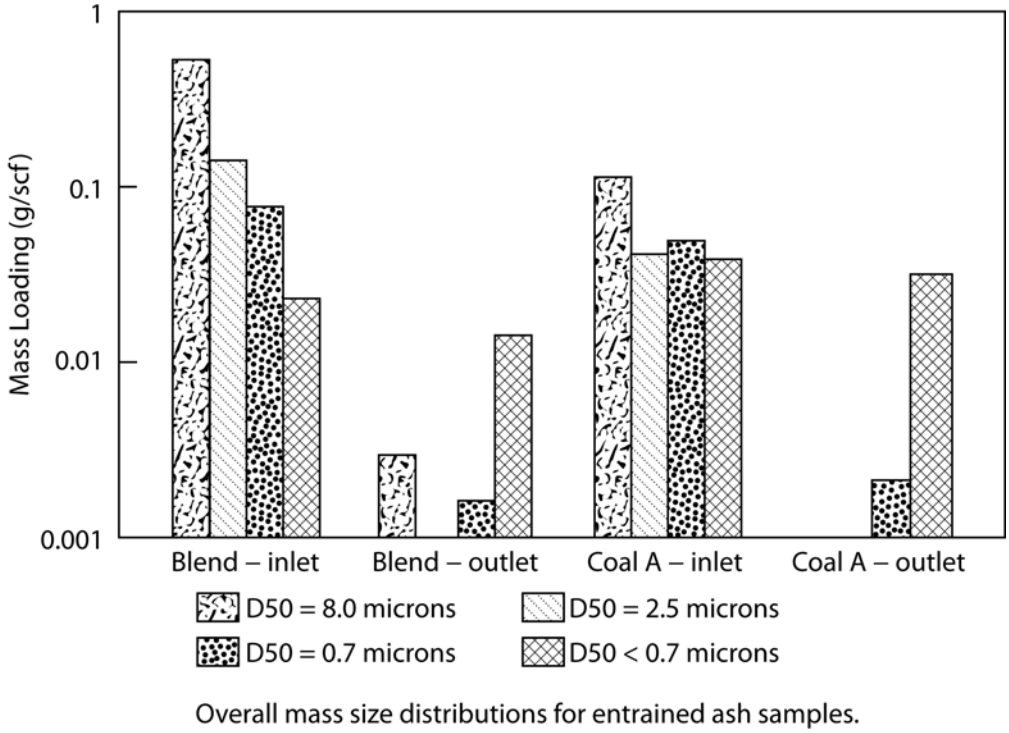


Figure C-11. Mass loadings and size for particulate collected upstream and downstream of the wet venturi scrubber at Clay Boswell (Hurley and Katrinak, 1992).

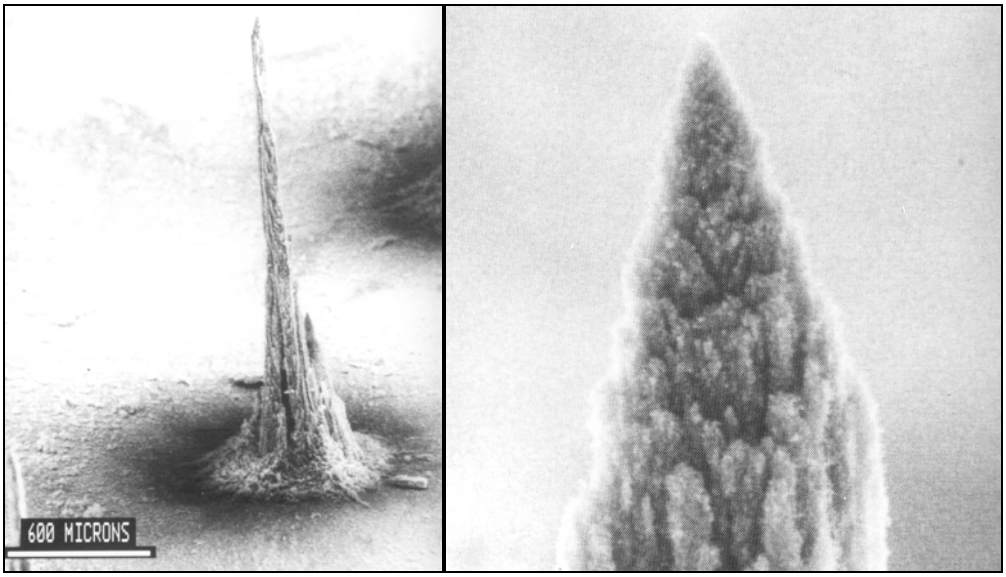


Figure C-12. Scanning electron microscope images of spike formed on impactor plate upon combustion of high-sodium subbituminous coal (right - close-up of spike) (Hurley and Katrinak, 1992).

Table C-4. Chemical Composition of the Spike Shown in Figure C-12 and the Filter (weight percent expressed as equivalent oxide).

	100% Coal A	
Oxide	Spike	Filter
Na_2O	**35.1**	**17.3**
MgO	1.4	7.8
Al_2O_3	2.0	9.8
SiO_2	9.1	10.6
P_2O_5	0.4	0.2
SO_3	**39.7**	**28.0**
K_2O	2.6	1.5
CaO	6.2	15.7
TiO_2	0.2	1.8
Cr_2O_3	1.4	0.1
Fe_2O_3	0.9	2.9
BaO	0.5	2.6

In addition to the aforementioned testing results, penetration of submicron particles through ESP and scrubbers has been reported by numerous researchers (Markowski and others, 1983, and Lighty and others, 2000).

Power Span Testing at MRY

Aerosols passing through the ESP at MRY Unit 1 resulted in significant accumulation on Powerspan's ECO barrier discharge reactor resulting in significant degradation in performance. The ECO DBD reactor is located just downstream of the plant's ESP or fabric filter (FF) and can be exposed to aerosols. The DBD reactor has quartz electrode rods inside where electric current is passed in order to generate the plasma used to oxidize NO. The temperature of the flue gas at the DBD reactor ranged between 300°F and 350°F. The temperature of the quartz electrodes is approximately 100°F higher than the gas temperature.

The Powerspan ECO reactor slip stream system was designed by Powerspan and the EERC. The slip stream system was installed by the EERC at Minnkota Power Company's Milton R. Young Station Unit #1 down stream of the ESP where the flue gas temperature was ranged from 300°F to 350°F. The system was commissioned on July 3, 2007, operated for 107 days. Operational performance of the system was monitored and data were archived for post processing. A pair of electrodes were extracted and replaced on a bi-weekly basis. Each pair of electrodes were shipped to Powerspan for testing in their laboratory reactor. Tested electrodes were then shipped to the EERC for scanning electron microscopy imaging and x-ray microanalysis. Measurement of NOx conversion by the slip stream system was not possible due to the nitric acid production of the DBD reactor.

The operational observations, performance results, and lab testing showed that the system was adversely affected by ash fouling. NOx conversion by ash covered electrodes was significantly reduced. Figure C-13 compares rods exposed to flue gas and aerosols downstream of the ESP at MRY Unit 1. The abundance of sodium in coal fired during the Powerspan testing is shown in Figure C-14. The results show sodium levels measured by the full stream elemental

analyzer (FSEA) ranged from 3.5 to 6 % Na2O in ash. Figure C-15 shows the degradation in NO conversion as a result of being coated with aerosols. The NO conversion was severely impacted.

Figure C-13. Comparison of (left) clean quartz rod and (right) dirty quartz rod exposed to flue gas downstream of ESP at MRY Unit 1 for sixteen days.

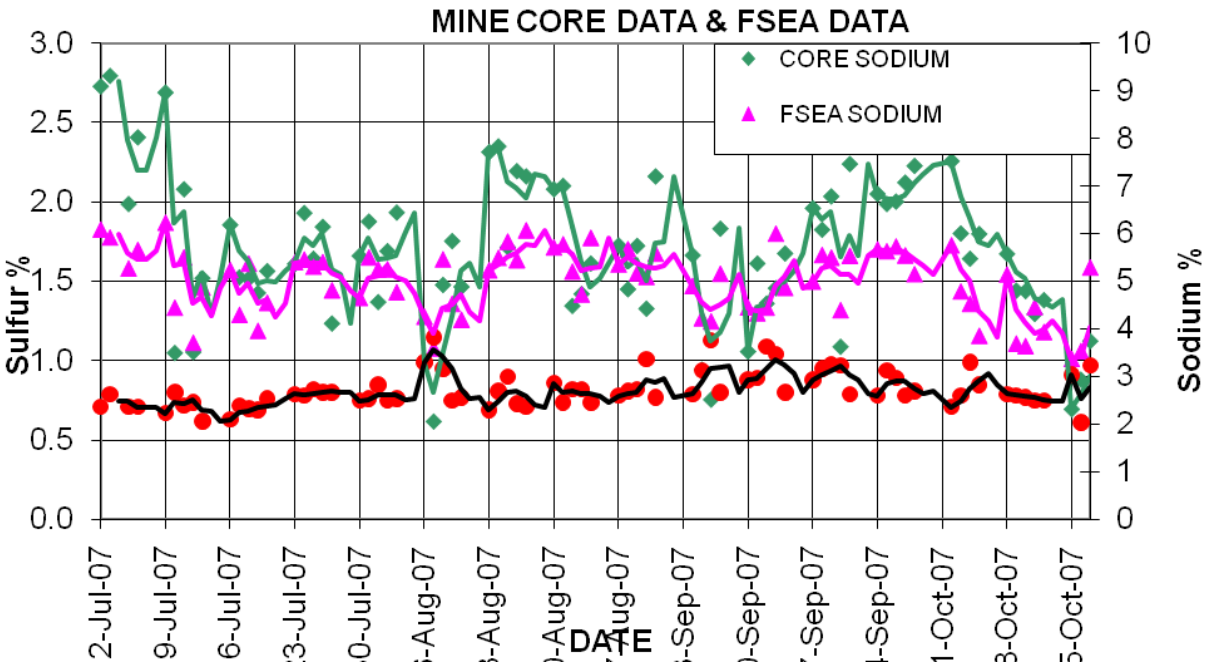


Figure C-14. Sodium and sulfur levels in lignite delivered during testing of the Powerspan barrier discharge reactor.

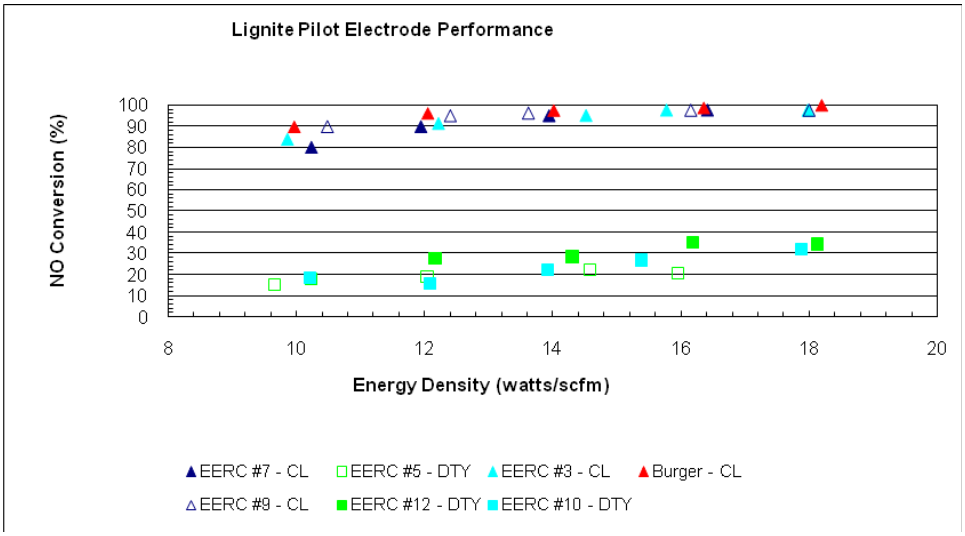
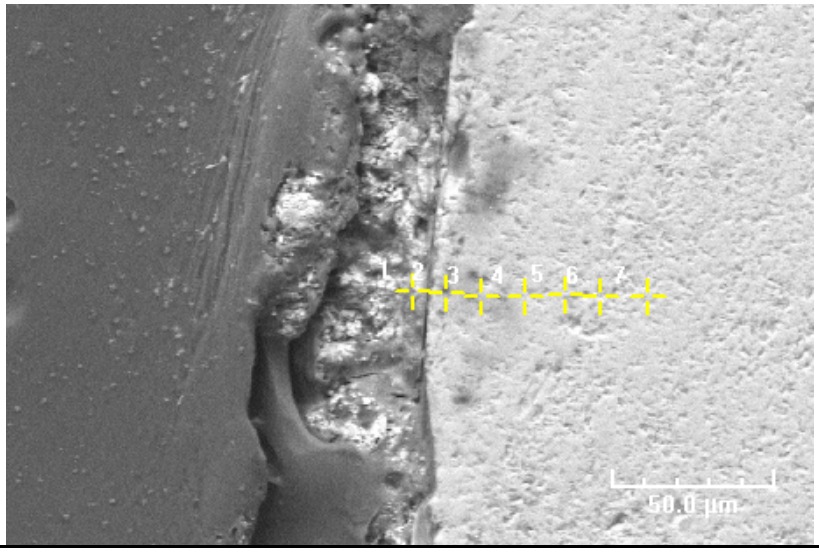


Figure C-15. NO conversion for clean (CL) and dirty (DTY) for quartz tube exposed the flue gas during the MRY testing.

Examination of the quartz rods (cross-sectioned to expose coating thickness) using scanning electron microscope elemental analysis showed significant elemental sodium, sulfur, and calcium in the ash coating the tubes after only 16 days of testing. The data is reported on Figure C-16. The thickness of the layer was approximately 25 µm. The rods were exposed to sootblowing. Images of the reactor and coatings on the electrodes are shown in Figure C-17.



Tag	Na	Mg	Al	Si	P	S	Cl	K	Ca	Ti	Fe	Ba
1	35.38%	0.98%	14.10%	4.68%	0.00%	35.75%	0.00%	1.42%	6.61%	0.02%	1.07%	0.00%
2	0.00%	0.00%	0.22%	98.52%	0.00%	0.00%	0.07%	0.89%	0.00%	0.30%	0.00%	0.00%
3	0.00%	0.00%	0.61%	98.11%	0.00%	0.00%	0.00%	1.05%	0.00%	0.00%	0.22%	0.00%
4	0.00%	0.00%	0.20%	98.33%	0.00%	0.00%	0.00%	1.19%	0.00%	0.00%	0.27%	0.00%
5	0.00%	0.00%	0.00%	98.70%	0.00%	0.00%	0.00%	1.24%	0.00%	0.00%	0.06%	0.00%
6	0.00%	0.00%	0.25%	97.26%	0.00%	0.00%	0.27%	1.70%	0.00%	0.00%	0.36%	0.16%
7	0.00%	0.00%	0.00%	97.93%	0.00%	0.00%	0.00%	1.55%	0.00%	0.00%	0.47%	0.05%

Figure C-16. SEM point analysis on electrode #11 (16 days of service).

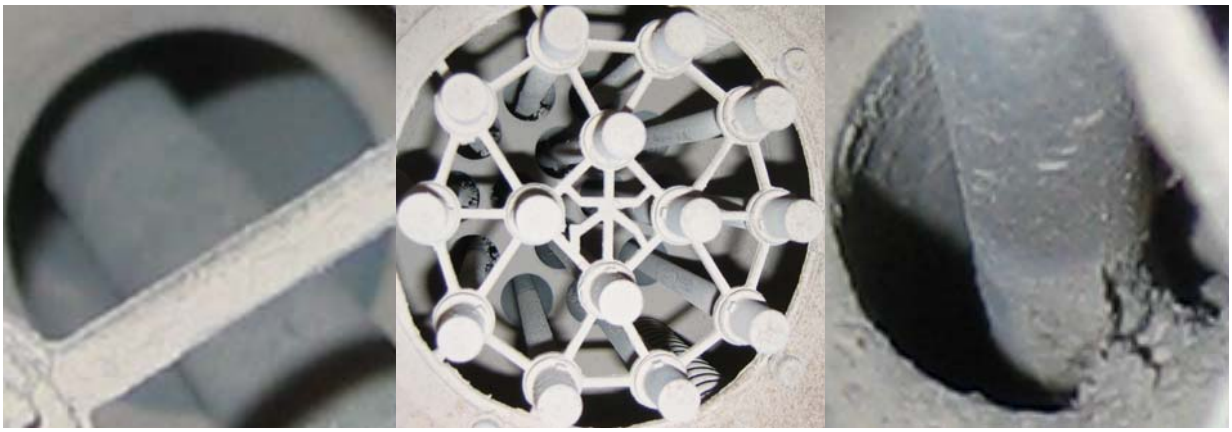


Figure C-17. Images of top of DBD reactor showing ash accumulations on electrodes and reactor surfaces.

Conclusions gained by this work were:

1. Sodium rich aerosols and small ash particles that had penetrated the ESP accumulate and become bonded on the surface of the silica electrodes in spite of soot blowing using a sonic horn as recommended by Powerspan.
2. Ash accumulations adversely affected the NOx conversion.
3. The adverse impact occurs within a two week time period.

MRY Sulfate Aerosol Sampling

The penetration of aerosols through ESP and wet scrubbers is well known and has been studied since the mid 1970s (McCain and others, 1975; Ensor and others, 1975). As a result of these challenges, the quantity of total aerosols and sulfate aerosols was measured at the MRY by Markowski and others, 1983. Markowski and others (1983) collected EPA Method 17 particulate samples and size-segregated the particles using an impactor (aerodynamically separates particles and allows for the characterization of each fraction). The results of the EPA method 17 sampling (mass concentration) conducted over a four-day period are illustrated in Figure C-18 for the inlet and outlet of the scrubber. At the inlet, aerosol mass concentrations ranged from a high of more than 10,000 $\mu g/m^3$ to a low of 4,000 $\mu g/m^3$. Significant levels were also found at the scrubber outlet, ranging from 8,800 to 2,500 $\mu g/m^3$. The removal efficiency varied from -25 to 66%.

Markowski and other (1983) offered no explanation of the differences in the levels of aerosols measured in the flue gas and removal efficiency. They did not consider that the ash content of the coal varied significantly during the testing. Results of testing at MRY have shown significant differences in the quantity vaporized for coals that have different ash contents (see Figure C-3). The variations in ash content shown in Figure C-18 reflect changing coal characteristics that resulted in differences in aerosol mass concentration.

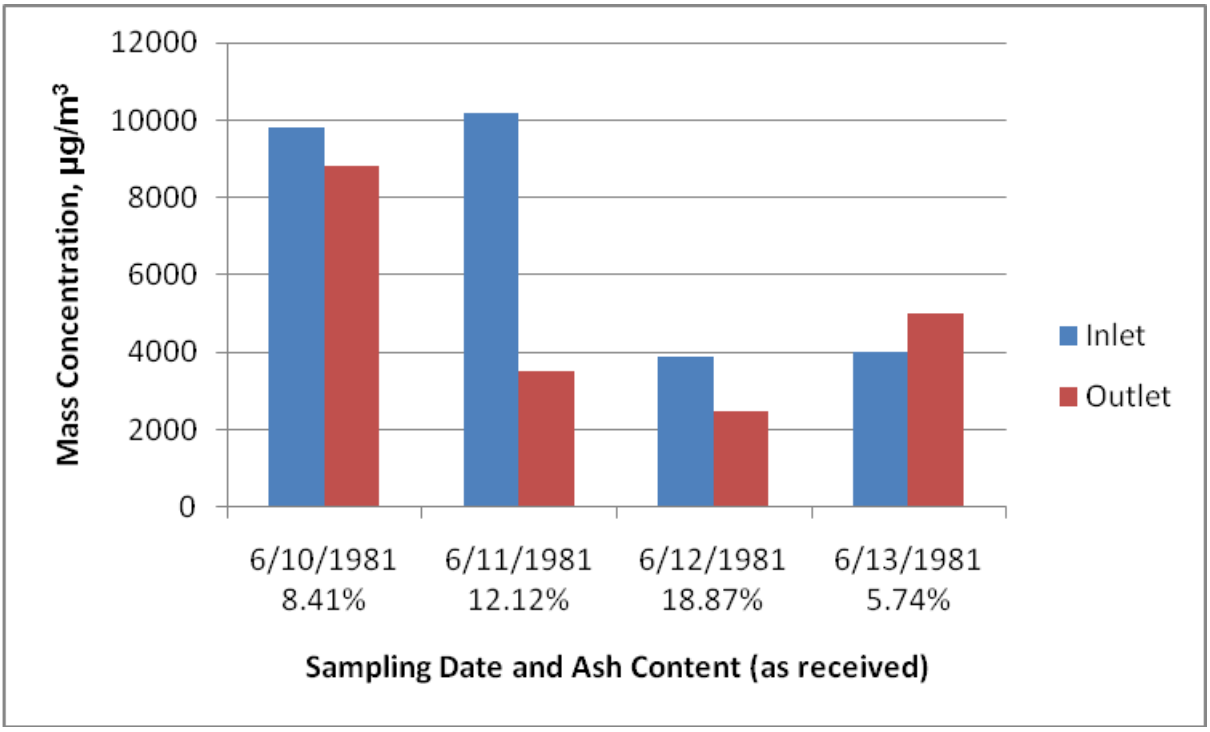


Figure C-18. Mass Concentration of Aerosol Collected at MRY Unit 2 at the Scrubber Inlet and Outlet (Markowski and others, 1983).

The results of the measurements of aerosol capture are illustrated in Figure C-19. The results show that aerosols less than one micrometer in diameter are not effectively captured in the wet FGD at the MRY facility. The graph also indicates the penetration of the particles through the FGD as a function of particle size. The penetration is the outlet size distribution divided by the inlet size distribution. (*Note: Penetration = 1- efficiency*). Markowski and others (1983) showed that the "metallic" sulfate aerosols (sodium sulfate) penetrated the FGD much more effectively than the larger particulate materials.

The mass of each of the impactor size fractions for the aerosols collected at the inlet and the outlet of the wet FGD upstream and downstream of the scrubber are illustrated in Figure C-20 and 21 with the results tabulated in Table C-5. The total mass distributions are summarized in Figure C-20 and the sulfate mass distribution is illustrated in Figure C-20.

Based on the impactor data the total mass of particulate that penetrates the scrubber is 5990 µg/m^3 (Markowski and others, 1983). These ash materials consist of a combination of sulfates and oxides of sodium, calcium, and sulfur. Much of the aerosol is present in the >14 µm size fraction. There are also significant mass in the less than 1 µm size fraction. All of these particles have the potential to penetrate the pores of the catalyst. In addition, there is a significant mass in the <0.26 µm fraction. This fraction represents the ultrafine component that has been implicated as the most significant contributor to catalyst poisoning (Kling and others, 2007).

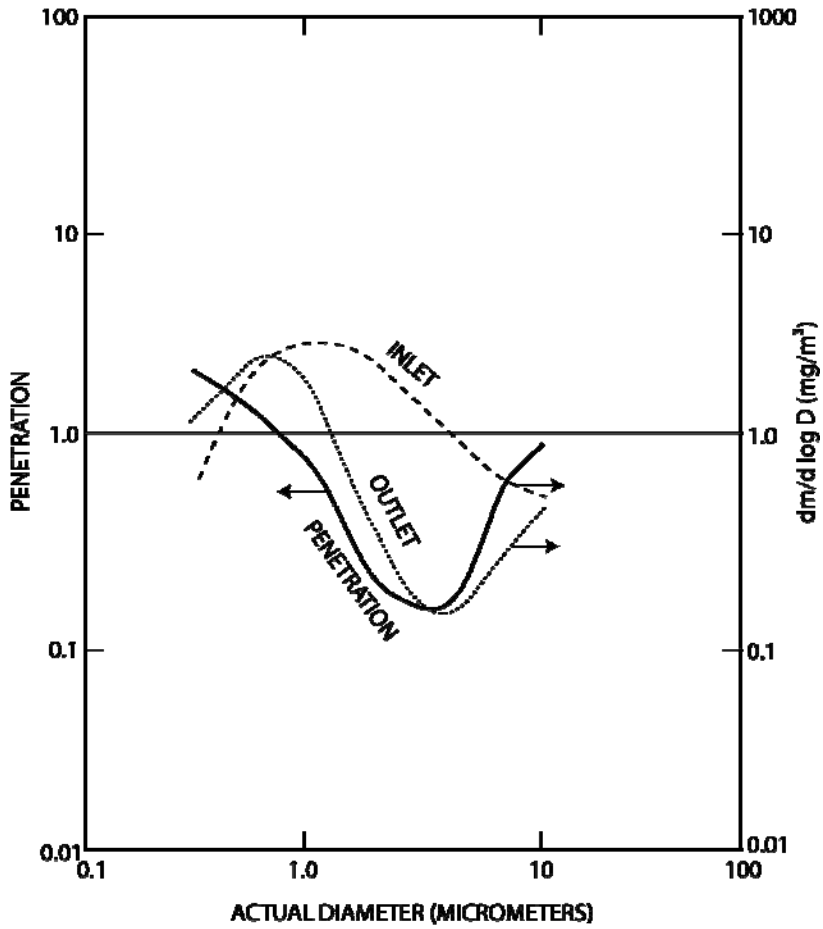


Figure C-19. Penetration through the wet scrubber (Markowski and others, 1983).

Table C-5. Size-segregated total and sulfate particulate collected upstream and downstream of the MRY FGD. (Markowski and others, 1983).

	Inlet	Outlet	Inlet	Outlet
Size, µm	Total, µg/m^3	Total, µg/m^3	Sulfate, µg/m^3	Sulfate, µg/m^3
<0.26	1910	769	436	602
0.26-0.52	401	640	164	274
0.52-1.1	883	1410	293	459
1.1-2.5	1020	265	291	69.2
2.5-6.7	337	154	173	94
6.7-14	300	367	100	103
>14	700	2390	439	46.2
Total	5550	5990	1896	1650
>1.1	2357	3176	1003	312.4
<1.1	3194	2819	893	1335
Percent				
>1.1	42.5 %	53.0 %	52.9 %	18.9 %
<1.1	57.5 %	47.1 %	47.1 %	80.9 %

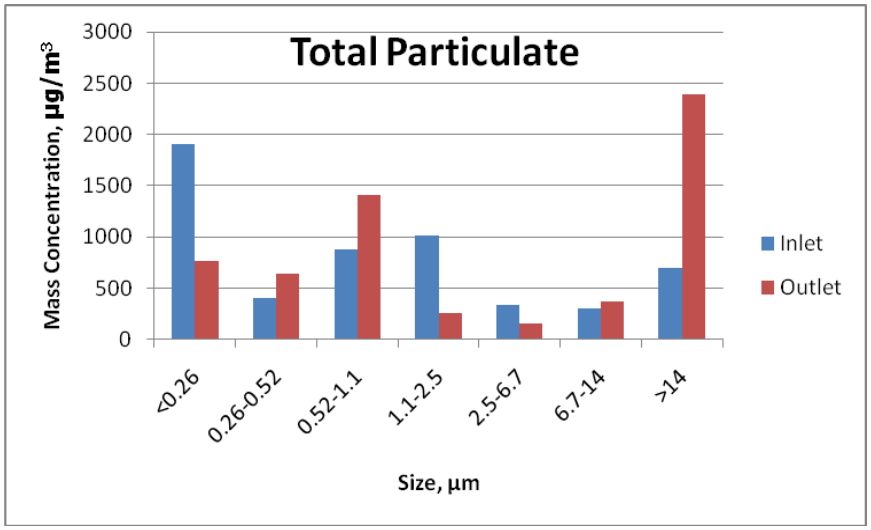


Figure C-20. Total particulate removal across scrubber at MRY.

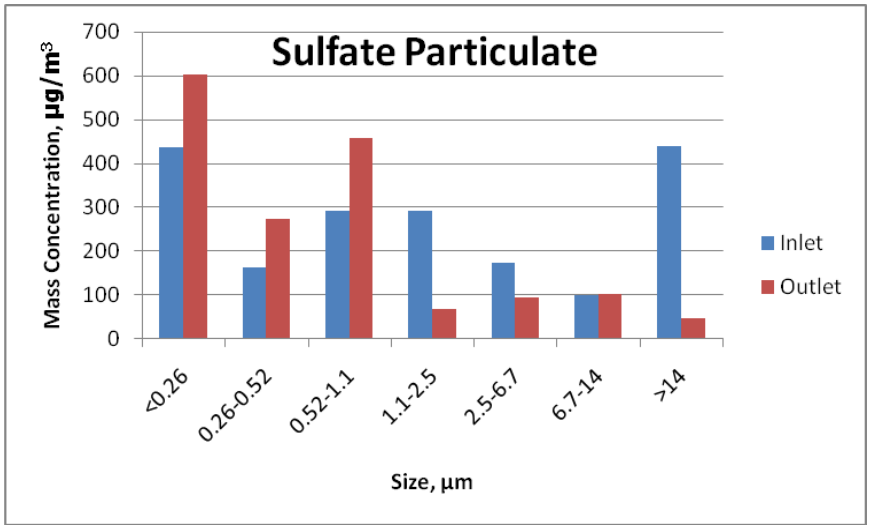


Figure C-21. Sulfate particulate removal across scrubber at MRY.

Estimation of Alkali Aerosol Loading and Catalyst Deactivation

The following data was used to estimate alkali aerosol loading and catalyst deactivation. The particle loading was based on the results of testing conducted by Markowski and others (1983) where they determined the mass loadings of aerosols at the inlet and outlet of the wet FGD at MRY Unit 2. The key data utilized is illustrated in Figure C-22 to estimate the loadings. The data provided shows a range of mass concentrations up to 8,800 µg/m^3 at the outlet of the scrubber. Based on results in mass size distribution of the aerosol 47 to 80% of the aerosols that pass through the scrubber is less than 1.1 µm. Much of this material is in the ultrafine fraction.

These materials have the potential to penetrate into the catalyst causing plugging and can react with active components in the catalyst. There are numerous publications supporting these mechanisms. Kling and others(2007) found that the rate of catalyst deactivation was related to the accumulation of sodium and potassium on the catalyst as shown in Figure C-23 and 24. The

work by Kling and others (2007) is consistent with the work conducted by Khodayari (2001) illustrated in Figure C-25 where it was shown that the deactivation rate is more significant for PC fired systems as compared to fluidized beds. The work based on Kling and others when applied to PC- and cyclone-fired systems will likely underestimate the degree of deactivation because of the firing methods.

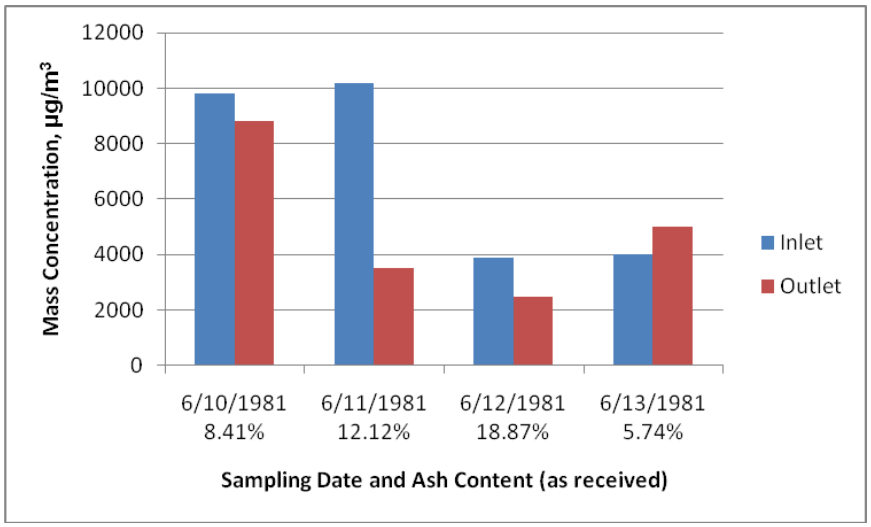


Figure C-22. Mass Concentration of particulate collected at MRY using EPA Method 17 (Markowski and others, 1983).

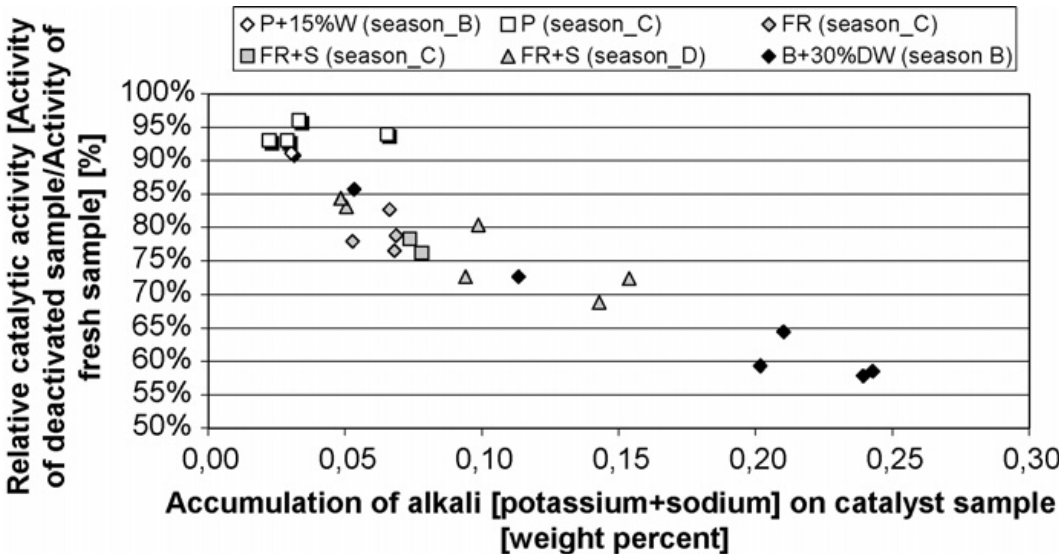


Figure C-23. Catalyst deactivation compared to accumulation of potassium and sodium on the catalyst surface (Kling and others, 2007).

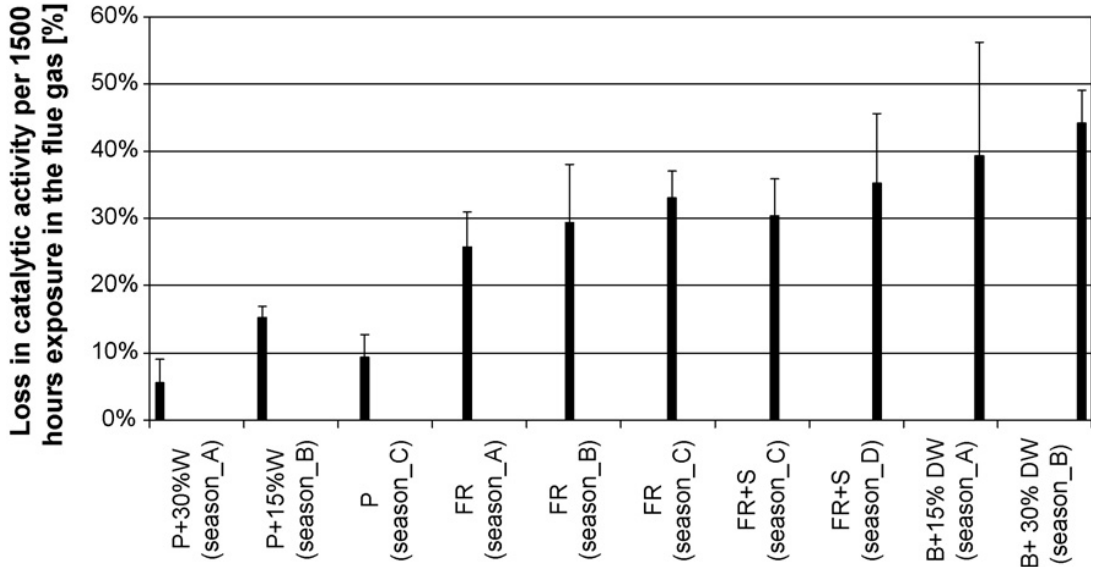


Figure C-24. Loss in catalyst activity when exposed to flue gases containing vaporized Na and K when combusting biomass in a fluidized bed combustion system (Kling and others, 2007).

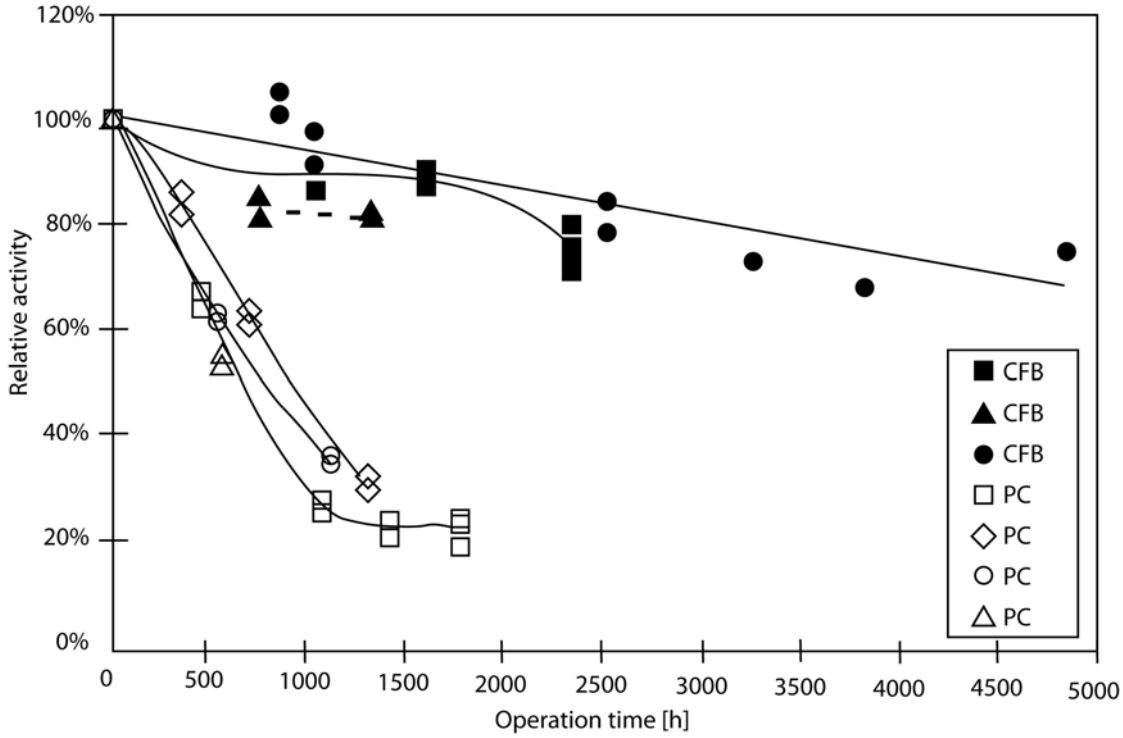


Figure C-25. Comparison of poisoning of catalysts in a CFB boiler firing forest residues, and in a PC firing pulverized wood (Khodayari, 2001).

REFERENCES

Benson, S.A.; Laumb, J.D.; Crocker, C.R.; Pavlish, J.H., SCR Catalyst Performance in Flue Gases Derived from Subbituminous and Lignite Coals. *Fuel Process*. *Technol*. **2005**, *86*, 577–613.

Benson, S.A.; Holm, P.L. Comparison of Inorganic Constituents in Three Low-Rank Coals. *Ind. Eng. Chem. Prod. Res. Dev.* **1985**, *24*, 145.

Benson, S.A.; Rindt, D.K.; Montgomery, G.G.; Sears, D.R. Microanalytical Characterization of a North Dakota Fly Ash. *Industrial and Engineering Product Research and Development* **1984**, *23*, 252.

Benson, S.A.; Jones, M.L.; Harb, J.N. Ash Formation and Deposition. In *Fundamentals of Coal Combustion for Clean and Efficient Use*; Smoot, D.L., Ed.; Coal Science and Technology 20 Series; Elsevier: Amsterdam, 1993; Chapter 4, pp 299–373.

Buecker, Brad, How Pollutants are Formed During Combustion (And How It Affects Control Methods), Power Engineering magazine, April 2008, accessed on-line at: http://pepei.pennnet.com/display_article/326581/6/ARTCL/none/none/1/How-Pollutants-AreFormed-During-Combustion-(And-How-It-Affects-Control-Methods)/

Chen, J.P.; Buzanowski, M.A.; Yang, R.T.; Cichanowicz, J.E., Deactivation of the Vanadia Catalyst in the Selective Catalytic Reduction Process. J. Air Waste Manage. Assoc. 1990, 40, 1403-1409.

Ensor, D.S., Jackson, B.S., Calvert, S., Lake, C., Walton, D.V., Nilan, R.E., Campbell, K.S., Cahill, T.A., Flocchini, R/G., EPA Report No. 600/12-75-074, Washington, D.C., 1975

Fisia Babcock SCR Installation Reference List, accessed on 11/3/2008 at http://www2.fisia-babcock.eu/references.php?list=5.

Guo, X., Poisoning and Sulfation on Vandia SCR Catalyst. Doctor of Philosophy Dissertation, Department of Chemical Engineering, Brigham Young University, August 2006.

Hurley, J.P.; Katrinak, K.A., Determination of Ash Formation and Deposition Mechanisms at Minnesota Power Clay Boswell Station; DOE/MC/10637-3365, July 1992.

ICAC Institute of Clean Air Companies, Particulate controls, http://www.icac.com/i4a/pages/index.cfm?pageid=3398

IEA Coal Research book “NOx control installations on coal-fired plants” (Rudow Unit 2 TESCR startup listed as 1990).

Khodayari, R., Andersson, C., Odenbrand, C.U.I., Andersson, L.H., in: Proceedings of the Fifth European Conference on Industrial Furnace and Boilers, vol. II, 11–14 April 2000, Espinho, Porto, Portugal, 2000.

Khodayari, R., Selective Catalytic Reduction of NOx: Deactivation and Regeneration Studies and Kinetic Modeling of Deactivation, Ph.D. Thesis, 2001, Dept. of Chemical Engineering II, Lund, Sweden.

Kling, A.; Andersson, C.; Myringer, A.; Eskilsson, D.; Jaras, S.G., Alkali Deactivation of High-Dust SCR Catalysts Used for NOx Reduction Exposed to Flue Gas from 100-MW-Scale Biofuel and Peat Fired Boilers: Influence of Flue Gas Composition. Applied Catalysis B: Environmental 2007, 69, 240-251.

Lind, T., Hokkinen, J., and Jokiniemi, J.K., Saarikoski,S., and Hillamo, R., Electrostatic Precipitator Collection efficiency and Trace Element Emissions from Co-Combustion of Biomass and Recovered Fuel in Fluidized-bed Combustion, Environmental Science and Technology, 2003, 37, 2842-2846.

Lighty, J.S., Varanth, J.M., and Sarofim, A.F., Combustion Aerosols: Factors Governing Their Size Composition and Implications to Human Health, J. Air & Waste Manage Assoc, 50:1565-1618, 2000.

Markowski, G.R., Downs, J.L., and Woffinden, G.J., Sulfate Aerosols from Western Low-Rank Coal-Fired Boilers with FGD: Summary of Tests at Coal Creek, Clay Boswell, Milton R. Young, and San Miguel Stations, DOE/FC/10182-t15 (DE83014539), May 1983.

McCain, J.D., Gooch, J.P., Smithw.B., J. Air Pollut. Control Assoc., 1975, 25, 117

Miles, T.R.; Miles, T.R.; Baxter, L.L.; Bryers, R.W.; Jenkins, B.M.; Oden, L.L., Alkali Deposits Found in Biomass Power Plants. A Preliminary Investigation of Their Extent and Nature; Summary Report for National Renewable Energy Laboratory Subcontract No. TZ-2-1-1226-1, April 1995.

Nobrega, S.W., Falaguasta, M.C.R., and Coury, J.R., A Study of a Wire-Plate Electrostatic Precipitator Operating in the Removal of Poly dispersed Particles, Brazilian Journal of Chemical Engineering, Vol 21, No. 02, pp 273-284, April-June 2004.

Noppenau, Henrik, Cleaner Fossil Fuels for Sustainable Development Co-firing Coal and Biomass, Accessed 10/28/2008 at http://www.usea.org/CFFS/CFFSNeptun/Co-firing%20-(WEC-CFFS)%20Neptun%20June%2013%202006.pdf

Ohlström, Mikeal, Jokiniemi, Jorma, Hokkinen, Jouni, Makkonen, Pasi, and Tissari, Jarkko, Combating Particulate Emissions in Energy Generation and Industry, Tekes, VTT Technical Research Centre of Finland, 2006.

Power Station Emissions Handbook, Cooperative Research Centre for Coal in Sustainable Development, http://www.ddsd.biz/PSE_Handbook/5/6/5/index.cfm accessed 11/24/2008.

Senior, C.L., Panagiotou, T, Sarofim, A. F., and Helble, J.J., Formation of Ultra-Fine Particulate Matter from Pulverized Coal Combustion, Preprints Division of Fuel Chemistry, American Chemical Society, 45(1), 2000.

Strege, J.R.; Zygarlicke, C.J.; Folkedahl, B.C.; SCR Deactivation in a Full-Scale Cofired Utility Boiler. Fuel 2008, 87 (7), 1341-1347.

Tolbert, S.G.; Benson, S.A. JV Task 117 - Impact of Lignite Properties on Powerspan's NOx Oxidation System; Final Report (May 1 - Dec 31, 2007) for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-98FT40321, Powerspan, Montana-Dakota Utilities Co., Minnesota Power, Basin Electric Power Cooperative, North Dakota Industrial Commission, and Minnkota Power Cooperative, Inc.; EERC Publication 2008-EERC-03-09; Energy & Environmental Research Center: Grand Forks, ND, April 2008.
White, Nathan, Washing Your Own Catalyst, NOx Round Table 2007, Cincinnati, Ohio, February 5-6, 2007.

Woodward, K. , Stationary Source Control Techniques Document for Fine Particulate Matter, EPA-452/R-97-001, October 1998. (http://www.epa.gov/ttncatc1/dir1/finepmtech.pdf)

Zheng, Y.; Jensen, A.D.; Johnsson, J.E. Deactivation of V2O5-WO3-TiO2 SCR Catalyst at a Biomass-Fired Combined Heat and Power Plant; Applied Catalysis B: Environmental 2005 60, 253-264.

Zheng, Y.; Jensen, A.D.; Johnsson, J.E.; Thøgersen, J.R. Deactivation of V2O5-WO3-TiO2 SCR Catalyst at Biomass Fired Power Plants: Elucidation of Mechanisms by Lab- and Pilot-Scale Experiments; Applied Catalysis B: Environmental. 2008, 83, 186-194.

Table 4 – MRYS Unit Design and Operating Parameters

Design Unit Operating Characteristics[1]	Unit 1 Design	Unit 2 Design
Boiler Type	Cyclone	Cyclone
Boiler Manufacturer	B&W	B&W
Boiler Design Heat Input Capacity (nameplate), mmBtu/hr	2,510	4,696
Unit Nameplate Generator Output Capacity, MW_g (gross)	257	477
Unit Nominal Full Load (NFL) Output, MW_g (gross)	235	450
Boiler Heat Input for Unit NFL Output, mmBtu/hr	2,508	4,814
Boiler Excess O_2, %, (wet, NFL)	3.17	4.04
Boiler Excess Air, % (NFL)	21.3	28.5
Fly Ash Portion of Total Ash, % (NFL)	45	50
Typical Maximum Continuous Rating (MCR) output, MW_g	253	462
Maximum Unit Output (URGE) Rating, MW_g	278	512
Boiler Firing Conditions for Flue Gas Flow Calculations:		
Boiler Heat Input, mmBtu/hr	2,852	4,740
Coal Higher Heating Value, Btu/lb as-received	6,578	6,578
Coal Flow Rate for heat input, lb/hr	433,500	720,500
Fly Ash Portion of Total Ash, %	50	50
Flue Gas Conditions at the boiler flue gas outlet:		
Boiler Excess O_2, %, (wet)	2.87	4.77
Boiler Excess Air, %	19.0	35.4
Flue Gas Mass Flow Rate, lb/hr	3,811,000	7,117,000
Flue Gas Volumetric Flow Rate, acfm	2,502,000	4,371,000
Flue Gas Temperature, degrees F	910	818
Flue Gas Pressure, in. w.g.	-11.5	-13.5
Boiler Outlet Maximum SO_2, lb/mmBtu	3.0[2]	3.0[2]
Boiler Outlet Maximum SO_2, lb/hr	8,970	15,474
Average Boiler Heat Input for SO_2, mmBtu/hr	2,990	5,158
Expected Boiler Outlet Maximum 30-day average SO_3, lb/hr	135[3]	236[3]

(1) – Boiler unit operating parameters are provided for more than one load or output condition.

(2) – Boiler Outlet Maximum SO_2 lb/mmBtu is based on 1.0% S and 6,578 Btu/lb higher heating value content in the as-received lignite coal.

(3) – Boiler Outlet Maximum SO_3 lb/hr is based on the assumed conversion of 1.5% of the boiler outlet SO_2 to SO_3 upstream of any flue gas treatment. This conversion percentage has not been confirmed by actual boiler outlet flue gas test measurements. The SO_2 lb/mmBtu and lb/hr values have not been reduced by this assumed SO_3 conversion.

Table C2 summarizes the average, maximum and minimum values for the entire as-fired coal database. The ranges on the various components can be very large. For example, the ash content ranges from 5 to 25%. Sodium oxide content ranges from 0.6 to 13% of the ash.

Table C2. Average, maximum, and minimum of basic coal analysis for all the coals in the as-fired database - Center Lignite Coal

ID NUMBER	Moisture	Ash	Sulfur	Btu	Volatile Matter	Fixed Carbon	Aluminum Oxide	Barium Oxide	Calcium Oxide	Iron Oxide	Magnesium Oxide	Manganese Dioxide	Phosphorus Pentoxide	Potassium Oxide	Silicon Dioxide	Sodium Oxide	Strontium Oxide	SO3	Titanium Dioxide	Basic total	Acid Total	Base/Acid Ratio
							Al_2O_3	Ba	CaO	Fe_2O_3	MgO	Mn	P_2O_5	K_2O	SiO_2	Na_2O	Sr	SO_3	TiO_2			
Average	**37.1**	**9.64**	**1.0**	**6578.1**	**25.3**	**28.0**	**11.7**	**0.5**	**13.2**	**8.9**	**4.0**	**0.1**	**0.1**	**1.3**	**36.0**	**4.4**	**0.4**	**18.4**	**0.5**			**0.7**
Max	**39.4**	**25.5**	**2.6**	**7101.0**	**31.1**	**31.2**	**15.6**	**1.2**	**24.0**	**24.7**	**7.1**	**0.3**	**1.0**	**2.3**	**56.0**	**13.0**	**37.0**	**34.5**	**0.7**			**2.5**
Min	**33.6**	**5.0**	**0.5**	**5852.0**	**22.3**	**13.7**	**6.3**	**0.2**	**6.8**	**5.4**	**2.3**	**0.0**	**0.0**	**0.2**	**12.3**	**0.6**	**0.2**	**8.1**	**0.2**			**0.3**
90th Perc.	**38.10**	**12.51**	**1.29**	**6820**	**26.5**	**29.9**	**14.2**	**0.8**	**19.9**	**12.2**	**5.7**	**0.1**	**0.4**	**1.9**	**46.0**	**8.71**	**0.6**	**26.3**	**0.6**			**1.26**
10th Perc.	**35.95**	**7.06**	**0.72**	**6359**	**24.3**	**26.1**	**9.6**	**0.4**	**9.7**	**7.1**	**3.0**	**0.1**	**0.0**	**0.6**	**22.7**	**1.99**	**0.2**	**14.4**	**0.4**			**0.44**
45th Perc.	**37.17**	**9.33**	**0.90**	**6552**	**25.2**	**28.0**	**11.6**	**0.5**	**12.2**	**8.3**	**3.8**	**0.1**	**0.1**	**1.4**	**37.0**	**4.09**	**0.3**	**17.3**	**0.5**			**0.592**
55th Perc.	**37.37**	**9.75**	**0.94**	**6592**	**25.4**	**28.3**	**12.0**	**0.5**	**12.7**	**8.7**	**4.0**	**0.1**	**0.1**	**1.4**	**38.4**	**4.61**	**0.4**	**18.0**	**0.5**			**0.637**

1. Ash weight percent was determined on an “as-fired” lignite coal basis.
2. BTU (higher heating value) content expressed on an “as-fired” lignite coal basis.
3. Constituent weight percent of the ash, elemental weight percent expressed as equivalent oxide.
4. B/A is the base to acid weight ratio of the ash constituents ($B/A=[Na_2O+MgO+CaO+ K_2O+FeO]/[SiO_2+Al_2O_3+TiO_2]$).

MDJ 3019-1

UTILITY BOILER PERFORMANCE SUMMARY

THIS SUMMARY SHEET IS THE PROPERTY OF THE BABCOCK & WILCOX CO. AND IS LOANED UPON THE UNDERSTANDING THAT IT IS NOT TO BE COPIED, IN WHOLE OR IN PART, OR USED FOR FURNISHING INFORMATION TO OTHERS, OR FOR ANY OTHER PURPOSE DETRIMENTAL TO THE INTERESTS OF THE BABCOCK & WILCOX CO. AND IS TO BE RETURNED UPON REQUEST.

A. FUEL AS FIRED

SAMPLES			
ANALYSES	SPECIFIED		
COAL — KIND			-
COAL — ASTM CLASS			IV
COAL — ASTM GROUP			I
COAL — SOURCE MINE			
COAL — SOURCE SEAM			
COAL — SOURCE DISTRICT			
COAL — SOURCE COUNTY			OLIVER
COAL — SOURCE STATE			N.D.
COAL — SIZE			
COAL — GRINDABILITY		22	30
COAL — SURFACE MOISTURE, %		3.0-5.0	5.0
ASH SOFT. TEMP., F (REDUCING)			
PROX. ANAL., % — MOISTURE, TOTAL		276-403	36.0
PROX. ANAL., % — VOLATILE MATTER		270-320	29.1
PROX. ANAL., % — FIXED CARBON		270-320	29.1
PROX. ANAL., % — ASH		3.9-8.3	5.8
PROX. ANAL., % — TOTAL			100.0
ULTIMATE ANALYSIS — FUEL		LIGNITE	LIGNITE
ULTIMATE ANALYSIS — % BY			WT.
ULTIMATE ANALYSIS — ASH		3.9-8.3	5.80
ULTIMATE ANALYSIS — S			0.74
ULTIMATE ANALYSIS — H_2		2.9-3.5	3.00
ULTIMATE ANALYSIS — C		38.9-46.1	40.40
ULTIMATE ANALYSIS — CH_4			
ULTIMATE ANALYSIS — C_2H_6			
ULTIMATE ANALYSIS — C_3H_8			
ULTIMATE ANALYSIS — C_4H_{10}			
ULTIMATE ANALYSIS — C_5H_{12}			
ULTIMATE ANALYSIS — C_6H_{14}			
ULTIMATE ANALYSIS — CO		.001-.001	0.01
ULTIMATE ANALYSIS — CO_2			
ULTIMATE ANALYSIS — SO_2			
ULTIMATE ANALYSIS — H_2O		275-40.3	36.00
ULTIMATE ANALYSIS — N_2		.4-.74	0.65
ULTIMATE ANALYSIS — O_2			13.40
ULTIMATE ANALYSIS — TOTAL			100.00
HHV/LB		6250-7830	6900
BTU/CU FT AT 60F 30 IN. HG			

B. PREDICTED PERFORMANCE

STEAM LEAVING SH, M LB/HR	990	1650	1714
STEAM LEAVING RH1, M LB/HR	876	1460	1534
STEAM LEAVING RH2, M LB/HR			
TYPE OF FUEL	LIGNITE		
LOAD DURATION	CONTINUOUS		
EXCESS AIR ENTERING AIRHEATER	31	28	28
NO. OF BURNERS IN OPERATION	7	7	7
FUEL INPUT, MMB/HR	1565	2422	2510
HEAT AVAIL. MMB/HR (FUEL & HEATED AIR)	1620	2559	2649
QUANTITY, LB/HR — FUEL (MCFH-NAT. GAS)	227	352	364
QUANTITY, LB/HR — FLUE GAS ENTERING AIR HEATER	2250	2817	2919
QUANTITY, LB/HR — AIR LEAVING SEC. AH & PRI. AH	1520	2312	2396
QUANTITY, LB/HR — AIR HEATER LEAKAGE			
PRESSURE, PSIG — STEAM AT SH OUTLET	1875	1875	1970
PRESSURE, PSIG — STEAM AT RH1 INLET	258	457	480
PRESSURE, PSIG — STEAM AT RH2 INLET			
PRESSURE DROP — REHEATER 1	15	25	26
PRESSURE DROP — REHEATER 2			
PRESSURE DROP — ECONOMIZER	11	30	33
PRESSURE DROP — DRUM TO SH OUTLET	45	125	135
TEMPERATURE, F — STEAM — LEAVING SUPERHEATER	1010	1010	1010
TEMPERATURE, F — STEAM — LEAVING REHEATER 1	970	1010	1010
TEMPERATURE, F — STEAM — ENTERING REHEATER 1	590	664	663
TEMPERATURE, F — STEAM — LEAVING REHEATER 2			
TEMPERATURE, F — STEAM — ENTERING REHEATER 2			
TEMPERATURE, F — FLUE GAS — LEAVING PRI. SH	810	890	900
TEMPERATURE, F — FLUE GAS — LEAVING AH (EXCL. LKG)	370	325	330
TEMPERATURE, F — FLUE GAS — LEAVING AH (INCL. LKG)			
TEMPERATURE, F — WATER ENTERING ECONOMIZER	408	461	466
TEMPERATURE, F — AIR — ENTERING AIR HEATER	100	100	100
TEMPERATURE, F — AIR — LEAVING AIR HEATER	735	768	777
RESISTANCE, IN. OF WATER — GAS — FURNACE & CONVECTION BANKS	2.4	3.7	4.0
RESISTANCE, IN. OF WATER — GAS — FLUES TO STACK	1.3	1.9	2.0
RESISTANCE, IN. OF WATER — GAS — AIR HEATER & ECON.	4.9	7.6	8.1
RESISTANCE, IN. OF WATER — GAS — DUST COLLECTOR	1.7	2.7	3.0
RESISTANCE, IN. OF WATER — GAS — TOTAL DRAFT LOSS	10.3	15.9	17.1
RESISTANCE, IN. OF WATER — AIR — FUEL BURNERS & WINDBOX	36.5	36.5	36.5
RESISTANCE, IN. OF WATER — AIR — DUCTS & FLOW METER	2.1	3.2	3.5
RESISTANCE, IN. OF WATER — AIR — AIR HEATER	1.5	2.4	2.6
RESISTANCE, IN. OF WATER — AIR — STEAM COIL AH	0.3	0.5	0.5
TOT. AIR RESISTANCE	40.4	42.6	43.1
HEAT LOSS, % — DRY GAS	6.70	5.46	5.58
HEAT LOSS, % — H_2 & H_2O IN FUEL	10.51	10.38	10.40
HEAT LOSS, % — MOISTURE IN AIR	0.17	0.14	0.14
HEAT LOSS, % — UNBURNED COMBUSTIBLE	0.10	0.10	0.10
HEAT LOSS, % — RADIATION	0.32	0.19	0.18
HEAT LOSS, % — UNACC. FOR & MFRS. MARGIN	1.10	1.10	1.10
HEAT LOSS, % — SLAG TANK	0.40	0.40	0.40
HEAT LOSS, % — TOTAL HEAT LOSS	19.30	17.77	17.90
EFFICIENCY OF UNIT, %	80.70	82.23	82.10
PULVERIZERS — NO. IN USE PER BOILER			
PULVERIZERS — TOTAL POWER, KWHR/TON MOTOR OUTPUT			
PULVERIZERS — % THRU 200 U.S.S. SIEVE			

PREDICTED PERFORMANCE IS BASED ON COMBUSTION AIR ENTERING UNIT WITH 0.013 LB MOISTURE/LB DRY AIR, ON 27.72 IN. HG. BAROMETRIC PRESSURE, ON CONDITIONS & EQUIPMENT GIVEN ON THIS SUMMARY SHEET & ON ARRANGEMENT SHOWN ON DRAWING 11X0

C. EQUIPMENT PER UNIT

TYPE	RADIANT
SIZE	RBC 57/CY.
	DESIGN PRESSURE 2325 PSIG
FURNACE PRESSURE PART. HEATING SURFACE, SQ FT — WATER COOLED SCREEN (CIRCUMFERENTIAL)	
WATER COOLED (PROJECTED)	33760
SUPERHEATER (CIRCUMFERENTIAL)	9229
SUPERHEATER (PROJECTED)	1200
TOTAL FURNACE HEATING SURFACE	44189
CONVECTION — SATURATED (CIRCUMFERENTIAL)	5910
CONVECTION — SUPERHEATER (CIRCUMFERENTIAL)	91607
CONVECTION — REHEATER 1 (CIRCUMFERENTIAL)	36947
CONVECTION — REHEATER 2 (CIRCUMFERENTIAL)	
CONVECTION — ECONOMIZER	44900
CONVECTION — TOTAL CONVECTION HEATING SURFACE	179164
TOTAL FURN. & CONV. PRESSURE PART. HTG. SURF.	223353
FLAT PROJECTED FURNACE HEATING SURFACE	
TO FACE OF PLATENS	37925
TO FACE OF CONVECTION SURFACE	
FURNACE VOLUME, CU FT	148800
AIR HEATER — TYPE TUBULAR	NO. 1
AIR HEATER — TOTAL HEATING SURFACE, SQ FT	742,000
FUEL BURNER — TYPE CYCLONE	
FUEL BURNER — NO. 7-10 FT. DIA.	
PULVERIZER — TYPE / SIZE / NO.	
PULVERIZER — CAPACITY OF / PULV. IS M LB STEAM/HR BASED ON GRIND	
PULVERIZER — BTU COAL AT % THRU 200 U.S.S. SIEVE	
PULVERIZER — FOR M LB COAL/PULV.-HR AT % THRU 200 U.S.S. SIEVE, MIN. GRIND	
PULVERIZER — IS , MAXIMUM SURFACE MOISTURE IS % REQUIRING F AIR	
STEAM TEMP. CONTROL	STEAM TEMPERATURE CONTROLLED BY GAS RECIRCULATION
UNIT CONSTRUCTION FEATURES	BALANCED DRAFT
	SEMI-OUTDOOR
	MEMBRANE WALL
	SOLIDS IN STEAM 1 PPM

REVISIONS	DESCRIPTION	BY	DATE

BY [illegible] APPD. DATE APRIL 1967

THE BABCOCK & WILCOX COMPANY

P1-3941-11X0-1S0

1

MINNESOTA POWER COOPERATIVE
SANDERSON AND PORTER, INC.
ENGINEERS

235MWe UNIT 1 RB-457

TO:9P18163333690 P:5/5
FROM:MINNKOTA POWER 7017947258
7-2002 13:44
THIS SHEET IS THE PROPERTY OF THE BABCOCK & WILCOX COMPANY AND IS LOANED UPON CONDITION THAT IT IS NOT TO BE COPIED, IN WHOLE OR IN PART OR USED FOR FURNISHING INFORMATION TO OTHERS, OR FOR ANY OTHER PURPOSE DETRIMENTAL TO THE INTERESTS OF THE BABCOCK & WILCOX COMPANY AND IS TO BE RETURNED UPON REQUEST.

A FUEL AS FIRED

SAMPLES

ANALYSES CUSTOMER SPECIFICATIONS

		DESIGN	PERF.
COAL SOURCE	KIND	LIGNITE	LIGNITE
	CLASS		
	GROUP		
	MINE		
	SEAM		
	DISTRICT		
	COUNTY		
	STATE		OLIVER N. DAK.
SIZE			1¼ - 1½
GRINDABILITY		20 MIN	25
SURFACE MOISTURE, %	H=½W		
ASH SOFT. TEMP., F (REDUCING)		2235-2500	2410
PROX. ANAL., %	MOISTURE, TOTAL	38	38.4
	VOLATILE MATTER		25.0
	FIXED CARBON	1	25.0
	ASH	13	11.6
	TOTAL		100.0
ULTIMATE ANALYSIS	FUEL		LIGNITE
	% BY		WT.
	ASH		11.60
	S		0.63
	H_2		2.60
	C		34.70
	CH_4		
	C_2H_4		
	C_2H_6		
	C_3H_8		
	C_4H_{10}		
	C_5H_{12}		
	C_6H_{14}		
	CO		0.61
	CO_2		
	SO_2		
	H_2O		38.40
	N_2		0.56
	O_2		11.50
	TOTAL		100.00
	BTU/LB	6000	6250
	BTU/CU FT AT 60F 30 IN.HG		

* EXCL. STATIC HEAD AND FEED STOP AND CHECK VALVE.

** INPUT & ALL GENERAL PERFORMANCE INCLUDES ALLOWANCE FOR AVERAGE SOOT BLOWER STEAM CONSUMPTION RATE (40,000 LB/HR).

UTILITY BOILER PERFORMANCE SUMMARY

BY VFH APPD. RTP DATE 3-27-73

THE BABCOCK & WILCOX COMPANY

PS-2783-1Y0-1S1

B PREDICTED PERFORMANCE

STEAM LEAVING SH, M LB/HR		1830	2560	3050	3200
STEAM LEAVING RH1, M LB/HR		1510	2110	2513	2729.6
BLOWDOWN, M LB/HR		18.5	25.9	30.8	32.1
TYPE OF FUEL		LIGNITE	LIGNITE	LIGNITE	LIGNITE
LOAD CONDITION		NORMAL	NORMAL	NORMAL	NORMAL MAX
EXCESS AIR LEAVING ECON., %		38	31	28	25
NO. OF BURNERS IN OPERATION		12	12	12	12
FUEL INPUT, MMB/HR **		2849	3883	4505	4675
HEAT AVAIL. MMB/HR (FUEL & HEATED AIR)		2974	4080	4761	4975
QUANTITY, M LB/HR	FUEL	455.8	621.2	720.7	751.4
	FLUE GAS ENTERING AIR HEATER	3410	4439	5050	5264
	AIR TO BURNING EQUIPMENT	2932	3802	4330	4491
	AIR HEATER LEAKAGE				
PRESSURE, PSIG	STEAM AT SH OUTLET	2495	2495	2495	2620
	STEAM AT RH1 INLET	296	407	518	570
	STEAM AT RH2 INLET				
PRESSURE DROP	REHEATER 1	27	23	28	30
	REHEATER 2				
	ECONOMIZER TO DRUM*	17	30	46	50
	DRUM TO SH OUTLET	60	106	155	180
TEMPERATURE, F	STEAM: LEAVING SUPERHEATER	1005	1005	1005	1005
	LEAVING REHEATER 1	980	1005	1005	1005
	ENTERING REHEATER 1	545	582	618	626
	LEAVING REHEATER 2				
	ENTERING REHEATER 2				
	FLUE GAS: LEAVING ECONOMIZER TO AH/TO CR	756/560	818/620	863/685	870/695
	LEAVING AH (EXCL. LKG)	284	310	328	330
	LEAVING AH (INCL. LKG)				
	AIR: WATER ENTERING ECONOMIZER	421	450	473.7	483.7
	ENTERING UNIT	108	100	100	100
	LEAVING AIR HEATER	661	710	745	750
RESISTANCE, IN. OF WATER	GAS: FURNACE & CONVECTION BANKS	3.7	5.1	8.0	8.8
	FLUES TO AH OUTLET	1.6	2.2	2.7	2.8
	AIR HEATER	3.0	5.0	6.5	6.9
	TOT. FURN. TO AH OUTLET	8.3	12.5	17.2	18.5
	AIR: FUEL BURNERS & WINDBOX	43.0	43.0	43.0	44.5
	DUCTS	1.5	2.5	3.2	3.5
	AIR HEATER	2.1	3.6	4.7	5.1
	TOT. FROM FD FAN TO FURN.	46.6	49.1	50.9	53.1
HEAT LOSS, %	DRY GAS	4.79	5.20	5.53	5.58
	H_2 & H_2O IN FUEL	11.08	11.21	11.28	11.30
	MOISTURE IN AIR	0.12	0.13	0.14	0.14
	UNBURNED COMBUSTIBLE	0.10	0.10	0.10	0.10
	RADIATION	0.28	0.21	0.18	0.17
	UNACC. FOR & MFRS. MARGIN & SLAG TANK LOSS	1.83	1.83	1.83	1.83
	TOTAL HEAT LOSS	18.20	18.68	19.06	19.12
EFFICIENCY OF UNIT, %		81.80	81.32	80.94	80.88
PULVERIZER POWER	NO. IN USE PER BOILER				
	TOTAL POWER, KW HR/TON MOTOR OUTPUT				
	% THRU 200 U.S.S. SIEVE				

PREDICTED PERFORMANCE IS BASED ON COMBUSTION AIR ENTERING UNIT WITH 0.013 LB MOISTURE/LB DRY AIR, ON 27.72 IN. HG. BAROMETRIC PRESSURE, OR CONDITIONS & EQUIPMENT GIVEN ON THIS SUMMARY SHEET & ON ARRANGEMENT SHOWN ON DRAWING PS-2783-1Y0

C EQUIPMENT PER UNIT

TYPE RADIANT

SIZE RBC 48/CY

DESIGN PRESSURE 2950 PSIG

PRESSURE PART HEATING SURFACE, SQ FT — FURNACE	WATER COOLED SCREEN (CIRCUMFERENTIAL)	
	WATER COOLED (PROJECTED)	43,260
	SUPERHEATER (CIRCUMFERENTIAL)	
	SUPERHEATER (PROJECTED)	15,360
	TOTAL FURNACE HEATING SURFACE	58,620
CONVECTION	SATURATED (CIRCUMFERENTIAL)	7,120
	SUPERHEATER (CIRCUMFERENTIAL)	127,300
	REHEATER 1 (CIRCUMFERENTIAL)	55,060
	REHEATER 2 (CIRCUMFERENTIAL)	
	ECONOMIZER	161,425
	TOTAL CONVECTION HEATING SURFACE	351,905
TOTAL FURN. & CONV. PRESSURE PART. HTG. SURF.		410,525
FLAT PROJECTED FURNACE HEATING SURFACE	TO FACE OF PLATENS	45,520
	TO FACE OF CONVECTION SURFACE	60,390
FURNACE VOLUME, CU FT		403,500
a/h HEATER	TYPE TUBULAR	NO. 1
	TOTAL HEATING SURFACE, SQ FT	1,336,400
FUEL BURNER	TYPE CYCLONE	
	NO. 12	
PULVERIZER	TYPE SIZE NO.	
	CAPACITY OF PULV. IS M LB STEAM/HR BASED ON GRIND	
	BTU COAL AT % THRU 200 U.S.S. SIEVE	
	FOR M LB COAL/PULV.-HR AT % THRU 200 U.S.S. SIEVE MIN. GRIND	
	IS MAXIMUM SURFACE MOISTURE IS % REQUIRING F AIR	

SOLIDS IN STEAM - 0.1 PPM

STEAM TEMP. CONTROL: GAS RECIRCULATION

UNIT CONSTRUCTION FEATURES: MEMBRANE WALL, BALANCED DRAFT, INDOOR

REVISIONS	NO.	DESCRIPTION	BY	DATE
	0-1	C59	VFH	4/25/73

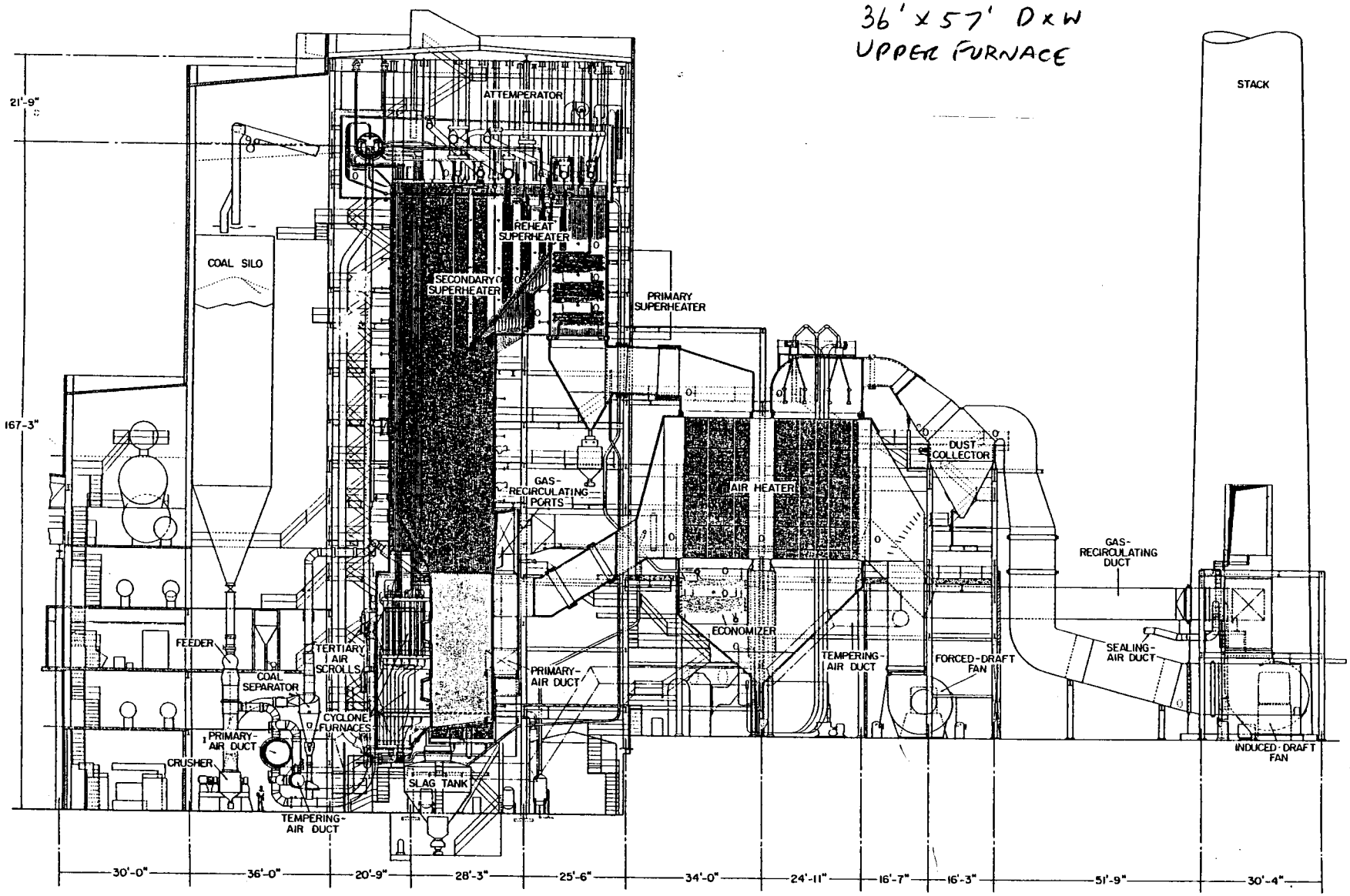
SANDERSON & PORTER, INC.
FOR: SQUARE BUTTE ELECTRIC COOPERATIVE, INC.
MILTON R. YOUNG STATION, NORTH DAKOTA

2

439 MWe RB-525

26' x 57' DxW
LOWER FURNACE

36' x 57' DxW
UPPER FURNACE

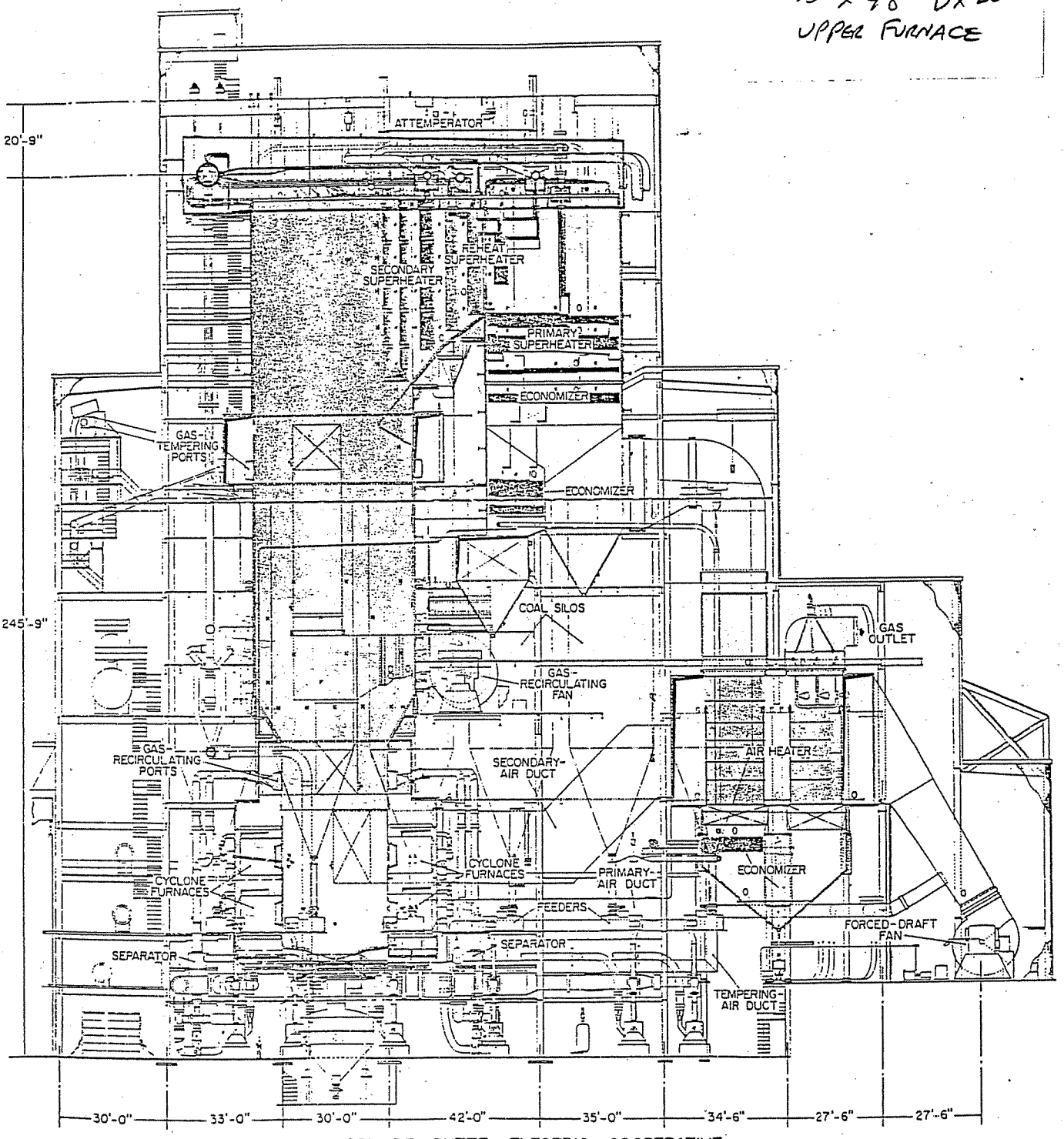


MINNKOTA POWER COOPERATIVE, INC.
CENTER POWER PLANT – UNIT NO. 1
CENTER, NORTH DAKOTA
B & W CONTRACT NO. RB-457

RB-457-500-2N

30' x 48' D x W
LOWER FURNACE

45' x 48' D x W
UPPER FURNACE



SQUARE BUTTE ELECTRIC COOPERATIVE
CENTER POWER PLANT—UNIT NO. 2
CENTER, NORTH DAKOTA
B & W CONTRACT NO. RB-525

Blakley, Robert

From: Robert Johnson [RJohnson@ftek.com]
Sent: Tuesday, September 01, 2009 6:57 AM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: Preliminary PFDs for MRY
Attachments: Sep09_MRY2TailEnd_Rev0_PFD.pdf; Sep09_MRY1LowDust_Rev0_PFD.pdf; Sep09_MRY1TailEnd_Rev0_PFD.pdf; Sep09_MRY2LowDust_Rev0_PFD.pdf

Bob,
Attached are the preliminary PFDs for Minnkota. Volker and I have yet to discuss these in detail, but we should be able to finalize them by the end of the week.

We can review these later at your office.

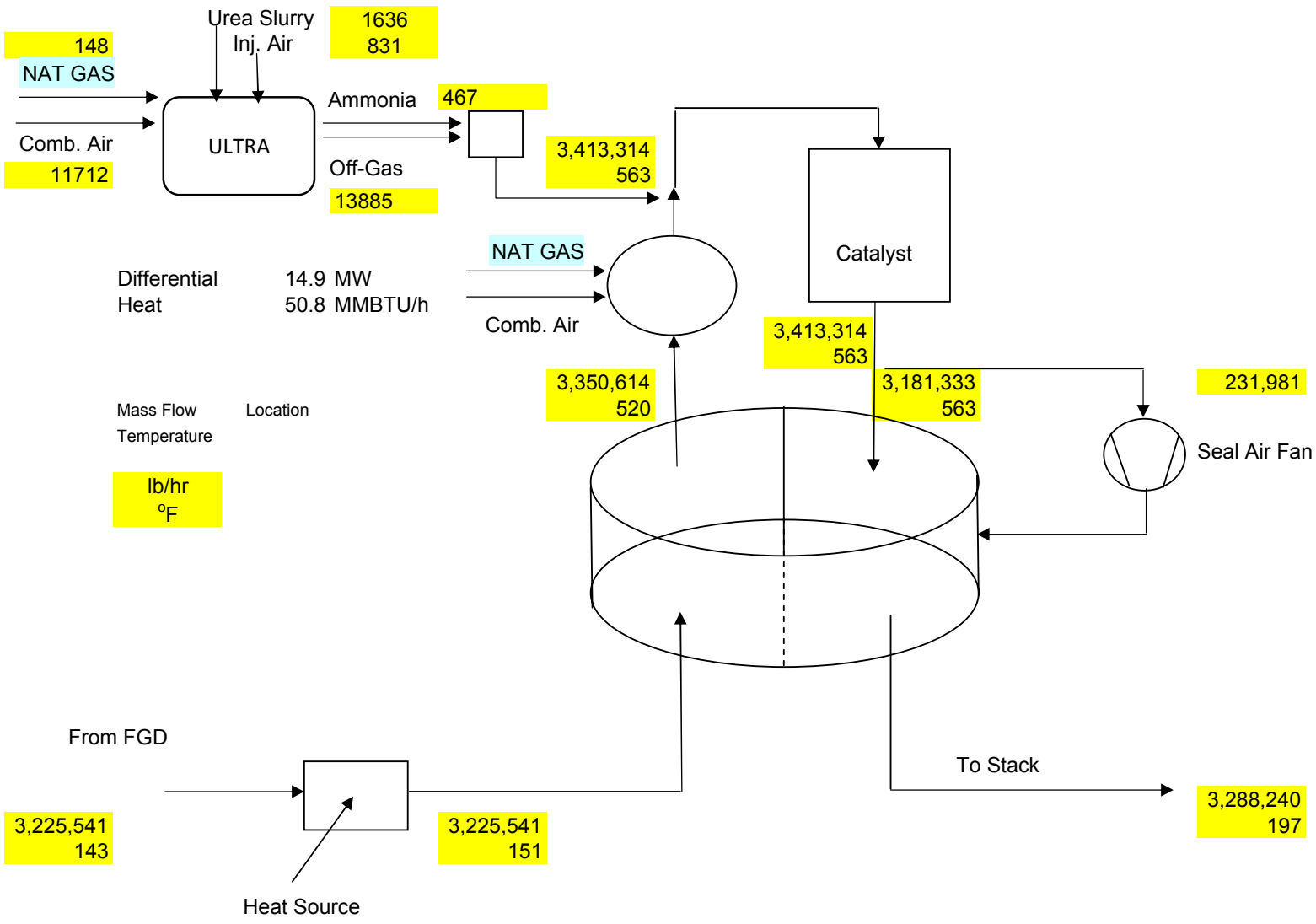
Thanks, Bob

Robert E. Johnson
Fuel Tech, Inc
(913) 897 0727

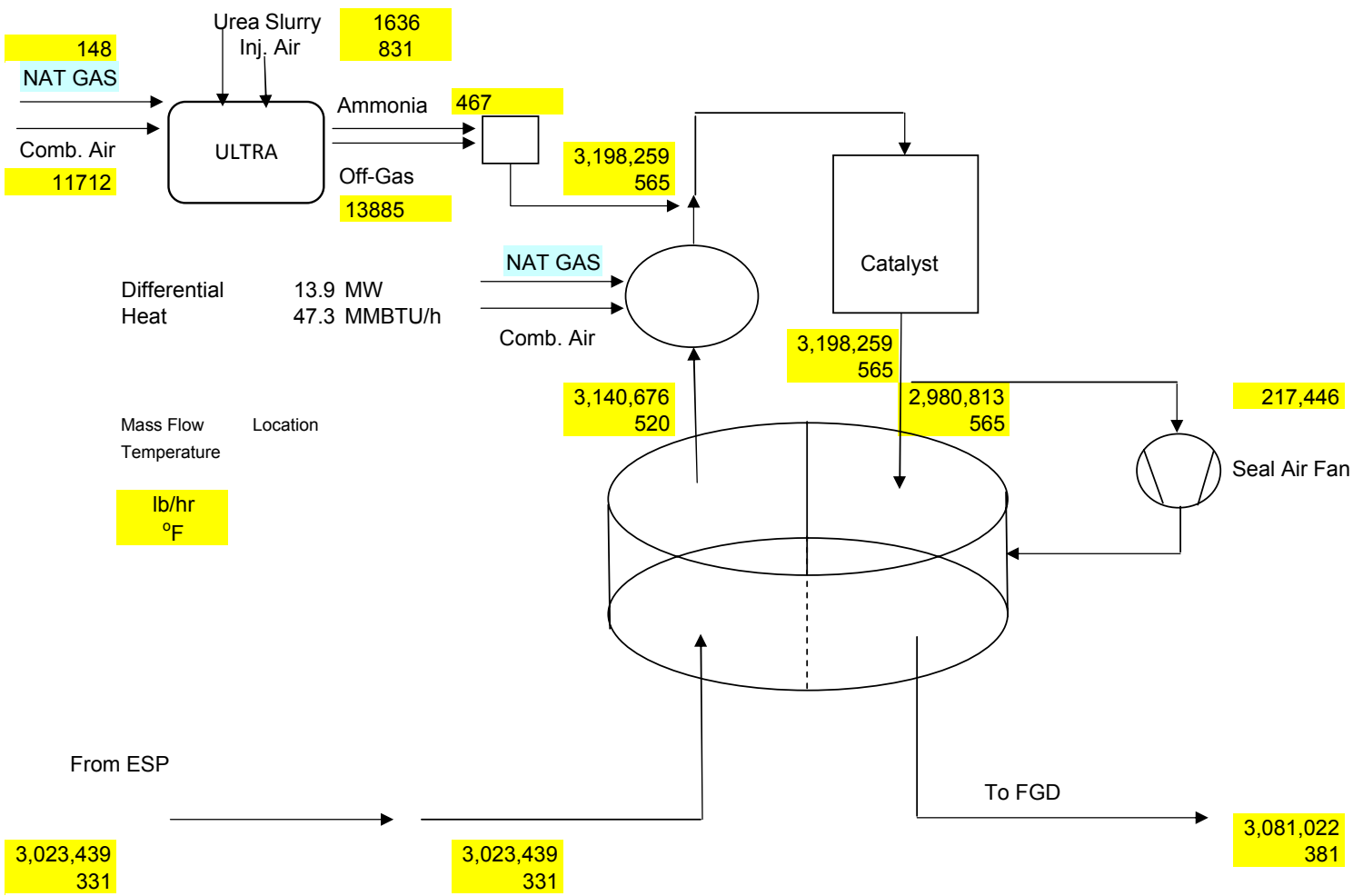
This message contains information that may be privileged, confidential or otherwise protected from disclosure. Unless you are the intended addressee (or authorized recipient for the addressee) you may not use, copy or disclose this message or information contained in this message to anyone. If you received this message in error, please notify the sender by replying to this message and then delete it from your system without copying or disclosing it. Thank you.

<<Sep09_MRY2TailEnd_Rev0_PFD.pdf>> <<Sep09_MRY1LowDust_Rev0_PFD.pdf>>
<<Sep09_MRY1TailEnd_Rev0_PFD.pdf>> <<Sep09_MRY2LowDust_Rev0_PFD.pdf>>

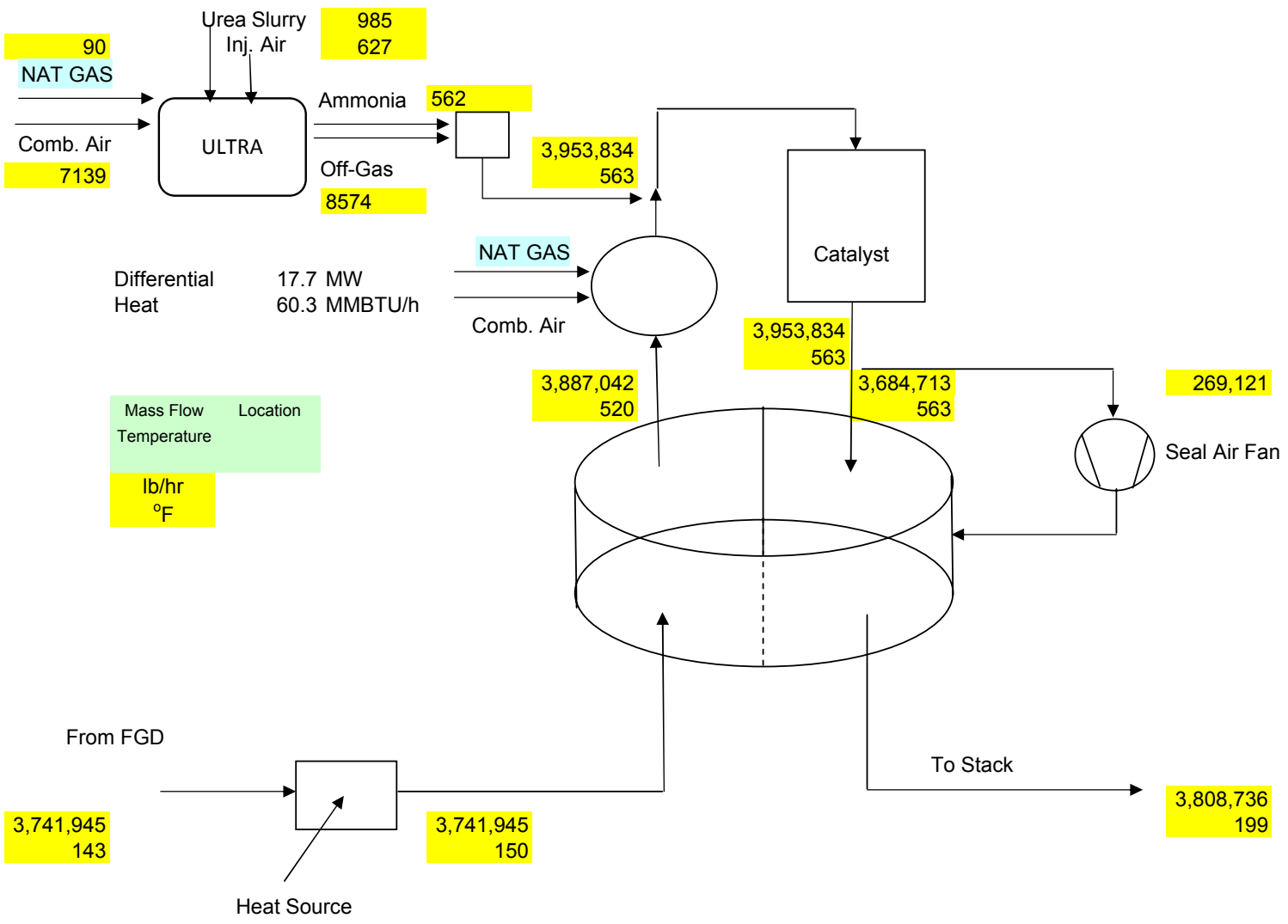
MRY 2 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



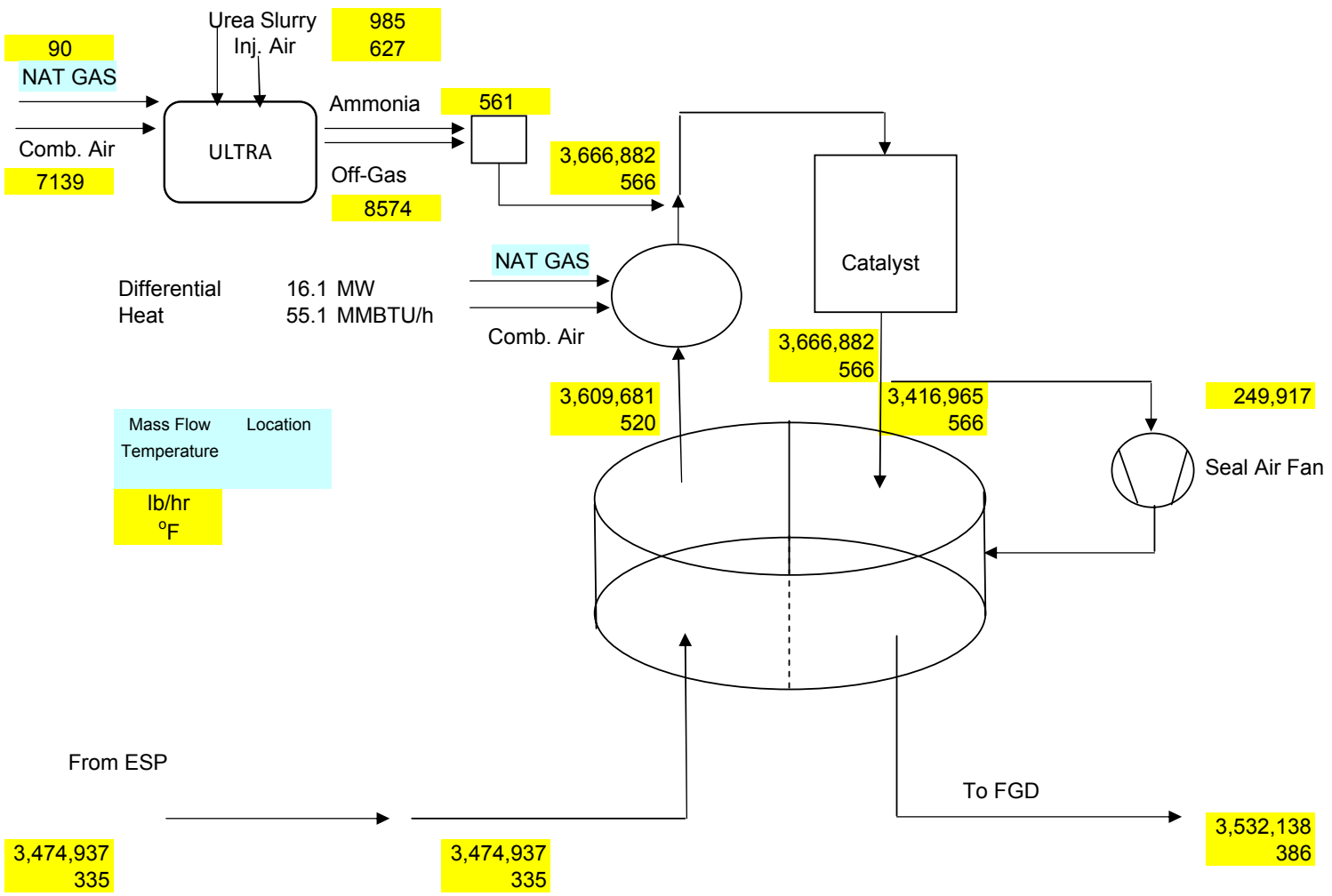
MRY 2 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



MRY 1 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



MRY 1 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



Blakley, Robert

From: Robert Johnson [RJohnson@ftek.com]
Sent: Thursday, September 03, 2009 3:00 PM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: RE: LD and TE SCR Review and Recommendations for MRYS
Attachments: Risiko_SINOx_E.pdf; GGH Brochure.pdf

Bob,
Thanks for compiling the discussion minutes. Volker and I have discussed these once and plan to do so again tomorrow. I will summarize our comments and send them along.

But, all of the attachments in your message are the same, though titled differently.

Attached is a brochure of the Hitachi FGD GGH that they have installed in Japan. it may be suitable and you may find the information useful.

Also, in anticipation of a response from the catalyst suppliers, I studied the Na concentrations from the tests at MRY. If I calculated correctly, 5,000 to 10,000 micrograms/Nm^3 are approximately 3 to 6 ppmv or 3.2 to 6.4 mg/Nm^3. according to Argillons Risk Analysis, this is right at the edge of their range. Let's see what Ceram and Topsoe have to say.

Best Regards, Bob

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Tuesday, September 01, 2009 5:04 PM
To: Robert Johnson; Volker Rummenhohl
Cc: 51684; Bryant, Ronald; Weilert, Carl; Voss, Steve
Subject: RE: LD and TE SCR Review and Recommendations for MRYS

Bob and Volker -

Here are the latest BMcD conceptual layout drawings of the ductwork and SCR/GGH "towers" that assume the Babcock Power approach for low-dust and tail end SCCR configurations. We are looking at one reactor for Unit 1 low dust or tail-end, and two reactors in parallel for Unit 2 low-dust or tail-end. We are looking for you to provide a review looking for "fatal flaws" or issues that could have significant impacts on function, performance, and capital cost.

Comments from our discussion with Bob in our office 9/1/09:
Our main concern is the potential leakage of untreated flue gas from the FGD GGH on the inlet side of the scrubber to the outlet side of the scrubber must be very close to zero, as any significant amount will make it difficult or impossible to maintain 95% SO2 removal across the wet scrubber. BPEI appears to be using a rotary regenerative type gas-gas heat exchanger for these SCR applications for both the FGD and SCR GGHs. They have not provided any details on these GGHs other than what we have already provided to you for review.

This approach does not reflect Steve Voss' idea raised this morning that the warm (dirty) side of the FGD GGH inlet be connected before the ID fan, so that any leakage would tend to be from the treated gas to the dirty gas side because of the higher pressure after the scrubber than before the ID fan.

We asked if there are other GGH options that have been proven successful in heat recovery-SCR operation that avoid the leakage issue. You said you could provide us with more information on such equipment.

We need to know where any special materials of construction may be required for corrosion resistance that are not obvious, such as after the tail-end SCR reactor to the chimney inlet, and the booster fan for this same location. This gas stream entering the

fiberglass-reinforced plastic Unit 2 chimney liner must be less than 200 degreesF continuously, although it will tolerate 400 degrees F upset for 15 minutes. We plan on adding an emergency quench header to protect the fiberglass liner and any ductwork from failure of the TE SCR GGHs. Because the flue gas downstream of a TE-SCR may have some SO3 that has been oxidized from SO2 remaining in the gas after the scrubber removes 95-97%, we welcome your comments on duct and fan materials.

We asked about startup of a LD- or TE-SCR after an extended boiler outage where everthing is cold. Does the flue gas need to be warmed up inside the reactors before exposing the catalyst to coal flue gas, especially for tail end where the GGHs don't have much heat to recycle?

How long could it take to cool down the reactor and remove and replace the catalyst was also of interest.

It would be helpful if you could provide some idea regarding possible budgetary cost and schedule estimates for a slip stream pilot SCR test program - low dust and tail-end configurations, from start to getting the results analyzed after operating for a significant amount of time with a suitably sized reactor and system that simulates low-dust and tail-end SCR conditions.

We'll be interested in further discussions once we have received the updated preliminary mass balances and other information. Let us know if you have any questions.

Thanks,

Bob Blakley

From: Blakley, Robert
Sent: Monday, August 31, 2009 4:41 PM
To: 'Robert Johnson'
Cc: 51684; Bryant, Ronald; Weilert, Carl; 'Volker Rummenhohl'; Voss, Steve
Subject: RE: LD and TE SCR Review and Recommendations for MRYS

Bob -

Thanks for calling me back and letting me know you are available for low-dust and tail-end SCR discussions for the Minnkota SCR Cost study project here in our office on Tuesday, 9/1 at 10 am.

Ron Bryant is arranging for food (pizza) so you can stay and join us for that if you wish.

I see this starting with the process review (updated preliminary mass balances and process flow diagrams), and then moving to the conceptual design review of the various SCR layouts, discussion of duct materials, booster fan locations, materials, and design pressure rise considerations, and then review of auxiliary systems.

I looked for the photos of Mercer Station that you mentioned, but it wasn't where I thought its was saved on the server and Steve Voss wasn't here to ask.

Bob Blakley

From: Blakley, Robert
Sent: Tuesday, August 25, 2009 5:17 PM
To: 'Robert Johnson'; Volker Rummenhohl
Cc: 51684; Bryant, Ronald; Weilert, Carl
Subject: LD and TE SCR Review and Recommendations for MRYS

Bob & Volker -

It's been awhile since we've emailed or talked. We hope you've been enjoying the summer weather. It's been relatively benign here in Kansas City.

We have been asked to proceed with performing a cost study and BACT cost effectiveness update for Minnkota's Unit 1 and Unit 2 involving low-dust and tail-end SCR technology. We are committed to having a draft cost study report to Minnkota for review by September 30, so we hope that you will be able to assist in this effort in the short term.

1. Update previous March 2009 LD and TE SCR preliminary mass balance calaculations with process flow diagrams - assuming a nominal NOx baseline of 0.50 lb/mmBtu with overfire air then 90% NOx reduction (30 day rolling average). We need you to convert numbers in the PFDs to English units (lbs/hr, deg F, in. w.c.), assuming a single SCR reactor for Unit 1 and two reactors in parallel for Unit 2.

2. Review of BMcD conceptual designs of reactors, GGH's, ductwork, and isolation damper locations (based on BPEI approaches) for "fatal flaws". Our preliminary layouts are attached, based upon a low-dust or tail-end SCR reactor "tower" that was developed by a system supplier recently involved with two low-dust projects in the U.S..

3. Recommendations for booster fans' locations for low-dust and tail-end SCR applications. We assume that avoiding a "wet" fan between the wet FGD outlet and SCR GGH is desirable, as well as having the SCR reactor under negative pressure.

4. Review of BMcD's selections for materials of construction for ductwork, and recommendations for GGHs and SCR reactor isolation dampers for TE SCR systems, assuming both Units have saturated flue gas following the wet lime FGD absorbers.

5. Recommendations for SCR catalyst online cleaning (air "knife" sootblowing rakes) and GGH online cleaning, assuming that high-pressure compressed air is preferred over steam. Is water needed to flush condensed acids from the FGD-GGH plates? Is this a continuous consumption? What do we need to consider and include in our cost estimate?

6. Recommendations for standby (outage) catalyst heating system - what do we need to consider and include in cost estimate.

7. TE SCR pilot slipstream - approach, cost and schedule estimates.

We have a total of four estimates and conceptual designs that we are developing:
>low-dust SCR for Unit 1,
> low dust SCR for Unit 2;
> tail-end SCR for Unit 1,
> tail-end SCR for Unit 2.
There are a few common systems that we also expect could be shared between the Units - urea solution receiving and storage; urea solution feed/circulation [to Fuel Tech "ULTRA" urea-to-ammonia conversion system(s)]; individual or common "ULTRA" system(s) to decompose the urea to ammonia gas; individual high-pressure compressed air compressor and air receiver tank(s) for on-line cleaning of the catalyst; individual standby (outage) catalyst heating system(s) - can this use the "Ultra" system without urea injection to provide heated air when the boiler is shutdown for fireside cleaning outages 3 or 4 times per year?

We have engaged two SCR system suppliers and two SCR catalyst manufacturers to help with our conceptual design efforts and installed cost estimates, but there are several areas (noted above) that we think that your experience could help improve the quality of our conceptual design development work.

Please confirm your interest and availability to assist on this effort. We are running short on time and your help would be very beneficial.

Bob Blakley
Associate Project Engineer
Energy Group
9400 Ward Parkway
Kansas City, MO 64114
Direct: 816-822-2842
Main: 816-333-9400
Fax: 816-333-3690
rblakley@burnsmcd.com
www.burnsmcd.com

HITACHI Non-Leakage Type Gas-Gas Heater

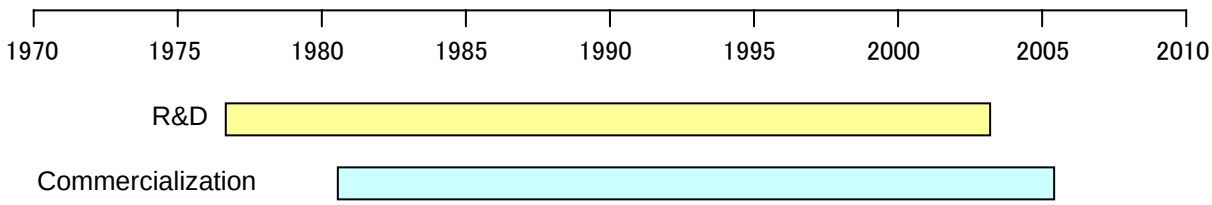
Hitachi Power Systems America
Basking Ridge, NJ

HITACHI
Inspire the Next

Technology Development

Babcock-Hitachi K.K.has started R&D activities for developing heat pipe technology in 1976. Since the first plant was delivered in 1978, Babcock-Hitachi K.K. has been working on the higher efficiency and rationalization of Gas-Gas Heater. Babcock-Hitachi K.K. has already delivered more than 10 non-leak type Gas-Gas Heater not only large-scale domestic power plant but also overseas, supported by boiler manufacturing technologies.
Non-leak type Gas-Gas heater is dispensable for stringent environmental emission.

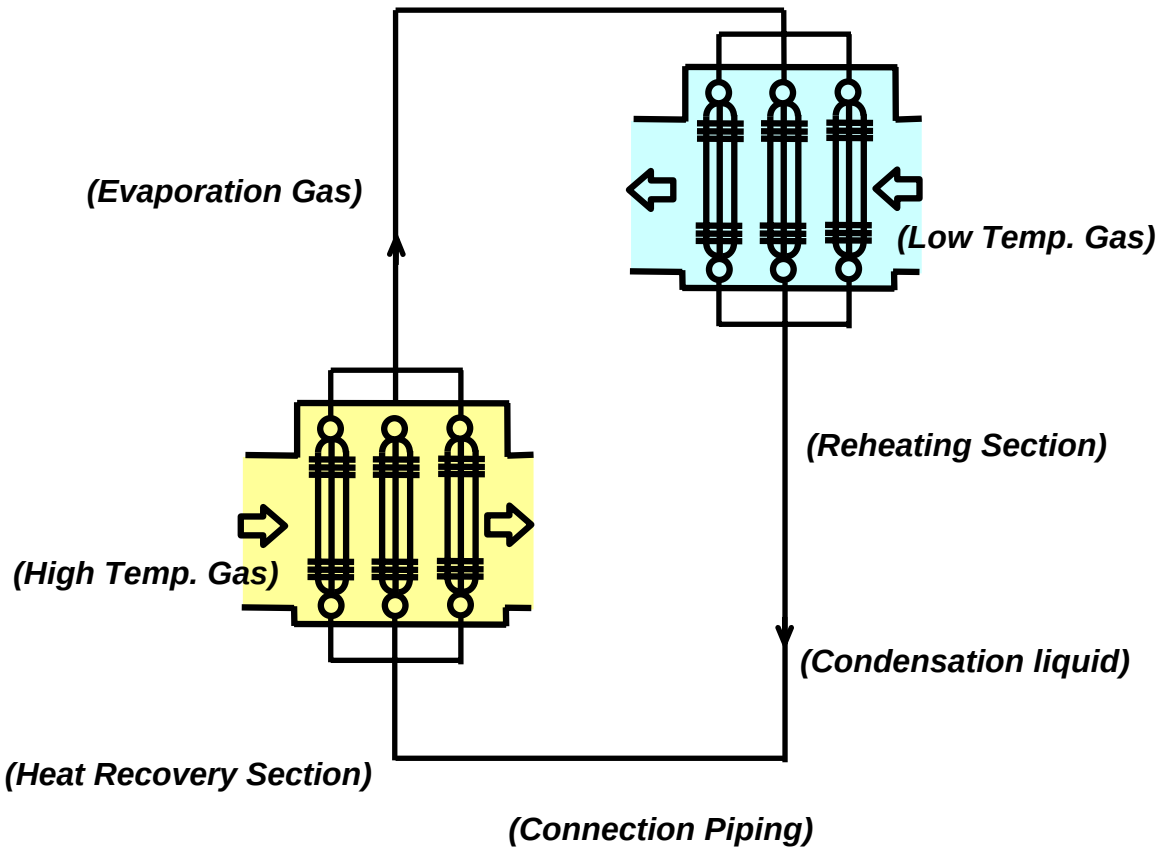
R&D and Commercialization Record



Application Concepts

(Heat Pipe Type)

A heat transfer medium,that is water, is hermetically sealed inside a vacuumed pipe container(Heat Pipe), which consists of a heat recovery (evaporation) section and a reheating (condensation) section. The transportation of the heat medium requires no power because of the use of gravity action,etc. Therefore this method requires no additional auxiliaries such as pumps, drives for rotation of heat exchanger unit which other heat exchangers do require.

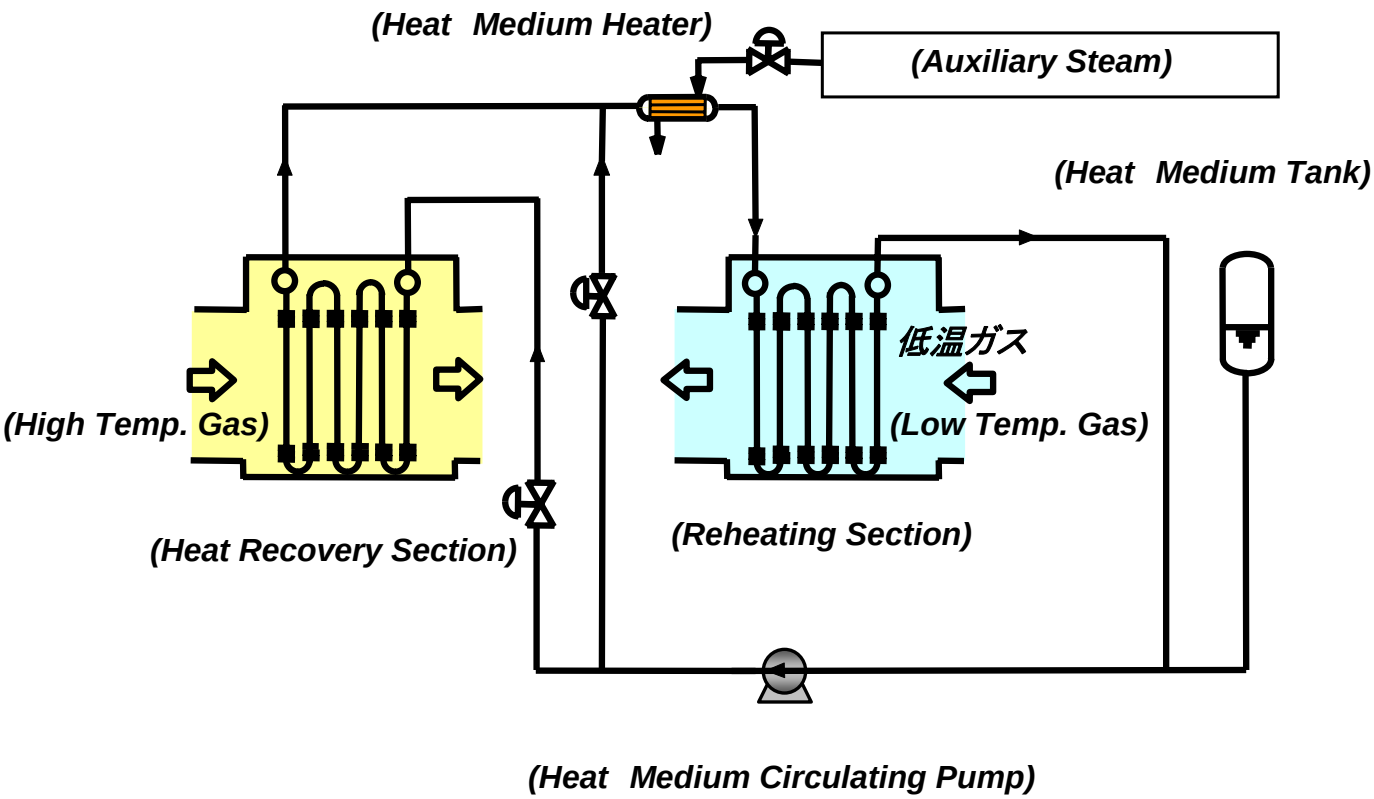


Flow Diagram of Heat Pipe Type

Application Concepts - continued

(Heat Medium Forced Circulated Type)

This type utilizes a pump forced hot water circulation system.Heat exchange between heat recovery section and reheating section can be achieved by circulating heat medium.
High temperature gas is cooled by heat recovery section, then low temperature gas is heated up to certain temperature by reheating section.
Although a heat pipe type needs to locate reheating section in a high position, this type does not have the restrictions on arrangement.



Flow Diagram of Heat Medium Forced Circulated Type

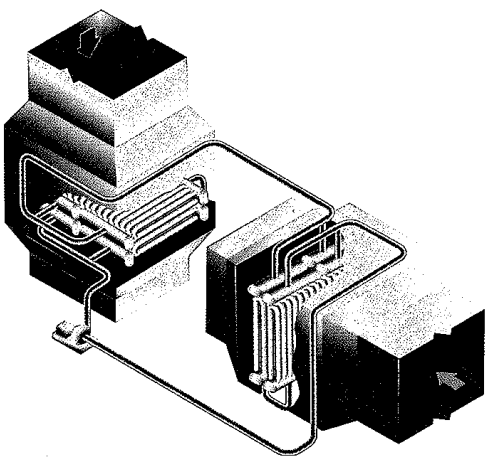
Features

EASY ARRANGEMENT

The heat recovery section and Reheating section are separated and are connected through re-circulation pipes.
This separate type helps to make duct arrangement easy.

NON LEAKAGE

There is no leakage of fluid. Therefore, this type can be used for Combustible fluid, Pressurized fluid, Poisonous fluid, etc. and can perform a high heat transfer efficiency.



Typical Configuration

Features - continued

EASY DESIGN FOR ANTI-CORROSION

Suitable material for the heat recovery section and reheating section can be selected separately.

EASY DESIGN FOR ANTI-CORROSION

By adopting the finned tube as heating tube, much heating surface area is obtained and compact arrangement is possible.
By adopting the optimal fin specification according to the flue gas composition, It makes long term stable operation possible.

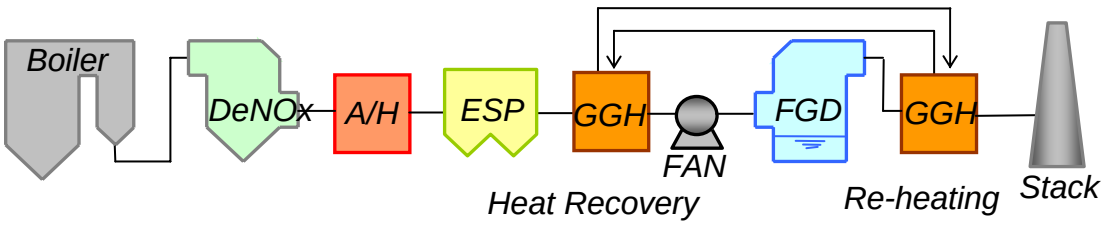
Heating Tube

The State of the Heating Tubes (After 2 yeas of operation)

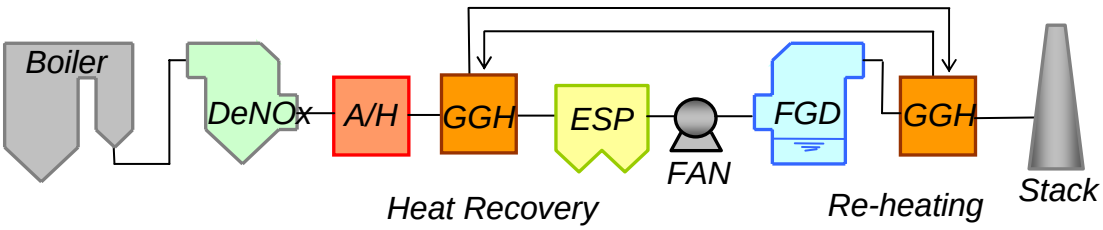
Applications

（1）(For FGD System)

TYPE －1



TYPE －2



In the FGD plant, it is necessary to make an exhaust gas re-heat as follows.

(1) Improvement of the Diffusion
(2) Prevention of the corrosion of Duct ,Stack
(3) Prevention of the visible gas

Babcock-Hitachi K.K. is one of the leader as the non-leak type Gas-Gas Heater which recovers heat from flue gas and reheat treated gas at the FGD without any leakage of untreated flue gas. According to more stringent emission, no leakage of untreated flue gas at the Gas-Gas Heater is dispensable for FGD instead of re-generative type Gas-Gas Heater.

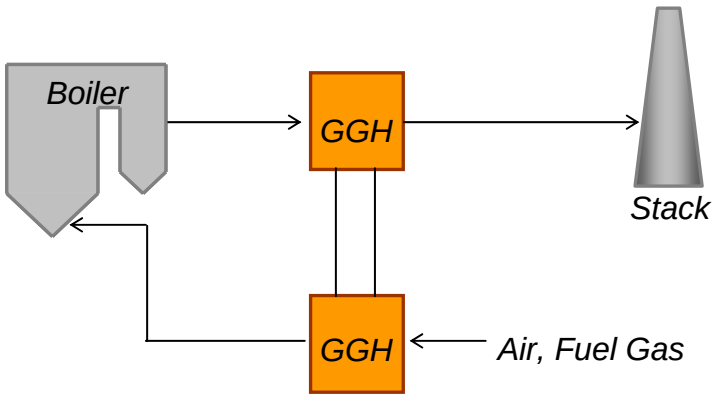
To the 1990s, Type -1 was in use.

Recently, Type -2 which can improve the dust removal performance of ESP is becoming in use because of strengthening of regulations of dust emission

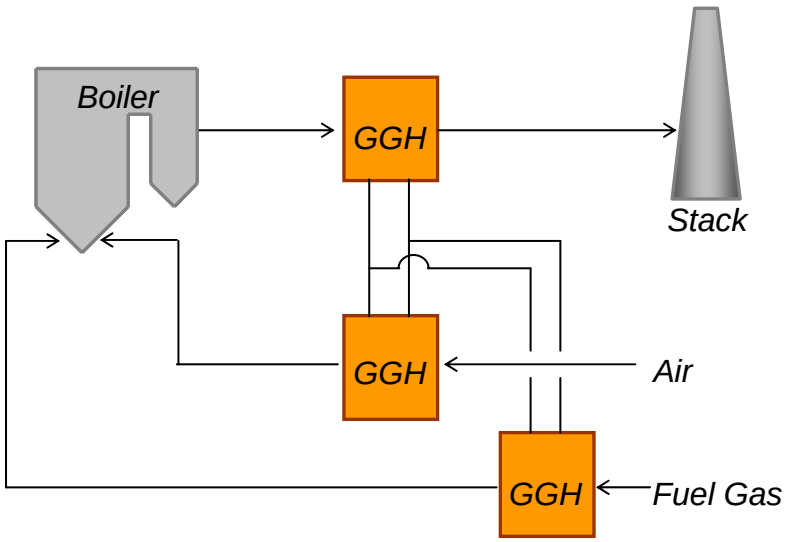
Applications - continued

(2) (For Fuel Gas/Air Preheat System)

TYPE −1



TYPE −2



Not only heat recovery of the boiler exhaust gas for power plant but reuse of various exhaust gases is possible.

Experience

HEAT PIPE TYPE

Item	Evaporation	Condensation
Fluid	Exhaust Gas	Air
Capacity	460,000m^{3}N/h	260,000m^{3}N/h
Inlet Temp.	230℃	15℃
Outlet Temp.	147℃	180℃
Heat Exchange	13.5 × 10^6 Kcal/h	
Customer	JFE Steel Corporation	
Service	Air Preheater for Blast Furnace Hot Stove	
Operation	Feb.1982	

HEAT PIPE TYPE

Item	Evaporation	Condensation
Fluid	Boiler Outlet Gas	FGD Outlet Gas
Capacity	3,075,000m^{3}N/h	3,282,060m^{3}N/h
Inlet Temp.	142℃	49℃
Outlet Temp.	96℃	93℃
Heat Exchange	47 × 10^6 Kcal/h (Boiler Capacity 1,000MW)	
Customer	Soma Kyodo Power Co,,Ltd.	
Service	For FGD System	
Operation	Jun.1994	

Experience - continued

Heat Medium Forced Circulated Type

Item	Heat Recovery	Reheating
Fluid	Boiler Outlet Gas	FGD Outlet Gas
Capacity	3,084,000m^{3}N/h	3,230,000m^{3}N/h
Inlet Temp.	133℃	47℃
Outlet Temp.	88℃	90℃
Heat Exchange	46 × 10^6 Kcal/h (Boiler Capacity 1,050MW)	
Customer	Electric Power Development Co,,Ltd.	
Service	For FGD System	
Operation	Dec.2000	

Heat Medium Forced Circulated Type

(Transport Situation of GGH Module)

Item	Heat Recovery	Reheating
Fluid	Boiler Outlet Gas	FGD Outlet Gas
Capacity	2,787,000m^{3}N/h	2,942,600m^{3}N/h
Inlet Temp.	126℃	51℃
Outlet Temp.	87℃	88℃
Heat Exchange	36 × 10^6 Kcal/h (Boiler Capacity 1,000MW)	
Customer	Chubu Electric Power Co,,Ltd.	
Service	For FGD System	
Operation	Nov.2001	

Data Required For Design

Please supply HITACHI with the following data when making inquiries;

Item	Unit	Specification	
		High Temp	Low Temp
Source of Fluid	—		
Fluid	—		
Capacity	m^3N/h		
Composition			
N_2	Vol%		
O_2	Vol%		
CO_2	Vol%		
H_2O	Vol%		
SO_2	ppm		
SO_3	ppm		
その他	—		
Dust	mg/m^3N		
Inlet Temp.	℃		
Outlet Temp.	℃		
Inlet Press.	mmH_2O		
Outlet Press.	mmH_2O		
Remarks	1. Fuel ? 2. Rough sketch of installation site giving altitude ?		

ARGILLON

List of Toxic Agents for SINOx® Systems and Catalysts

To keep our guarantee the following values (maximal concentrations of catalyst poisons in the exhaust gas) must be strictly respected:

Alkali metals	mg/m^3 wet.	max.	5
Alkaline-earth metals	mg/m^3 wet.	max.	1
Hydrochloric acid, chlorides	mg/m^3 wet.	max.	100
Hydrofluoric acid, fluorides	mg/m^3 wet	max.	1
P_2O_5, organic phosphorus Compound, As, As-compounds, Si-organics, Si-halides	mg/m^3 wet	max.	0,005
Pb + Zn	mg/m^3 wet	max.	0,1
Hg + Cd	mg/m^3 wet	max.	0,1

Rev.	Date	Provided by/Department.	Released by/ Department
5	May 1th, 2003	Dr. Michael Joisten / C P	Dr. Guenther Pajonk / C D

Blakley, Robert

From: Robert Johnson [RJohnson@ftek.com]
Sent: Friday, September 11, 2009 3:45 PM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: Updated PFDs for MRYS
Attachments: 11Sep09_MRY2TailEnd_Rev1_natgas.pdf; 11Sep09_MRY1LowDust_Rev1_natgas_580F.pdf; 11Sep09_MRY1TailEnd_Rev1_natgas.pdf; 11Sep09_MRY2LowDust_Rev1_natgas_580F.pdf

Bob,
Attached are updated PFDs and mass balance for the four options. We have added a table with flue gas constituents for the process.

After discussing the application some more, Volker and I recommend that the operating flue gas temperature for the LD cases should be raised to 580F. This is just to provide some margin pertaining to the minimum operating temperature of the SCR.

Also, as I mentioned in our discussion, these PFDs are still preliminary, pending selection of the GGH supplier and their opportunity to provide the balance around the GGH.

Volker and I are drafting comments re: other open items. We expect to issue this to you on Monday.

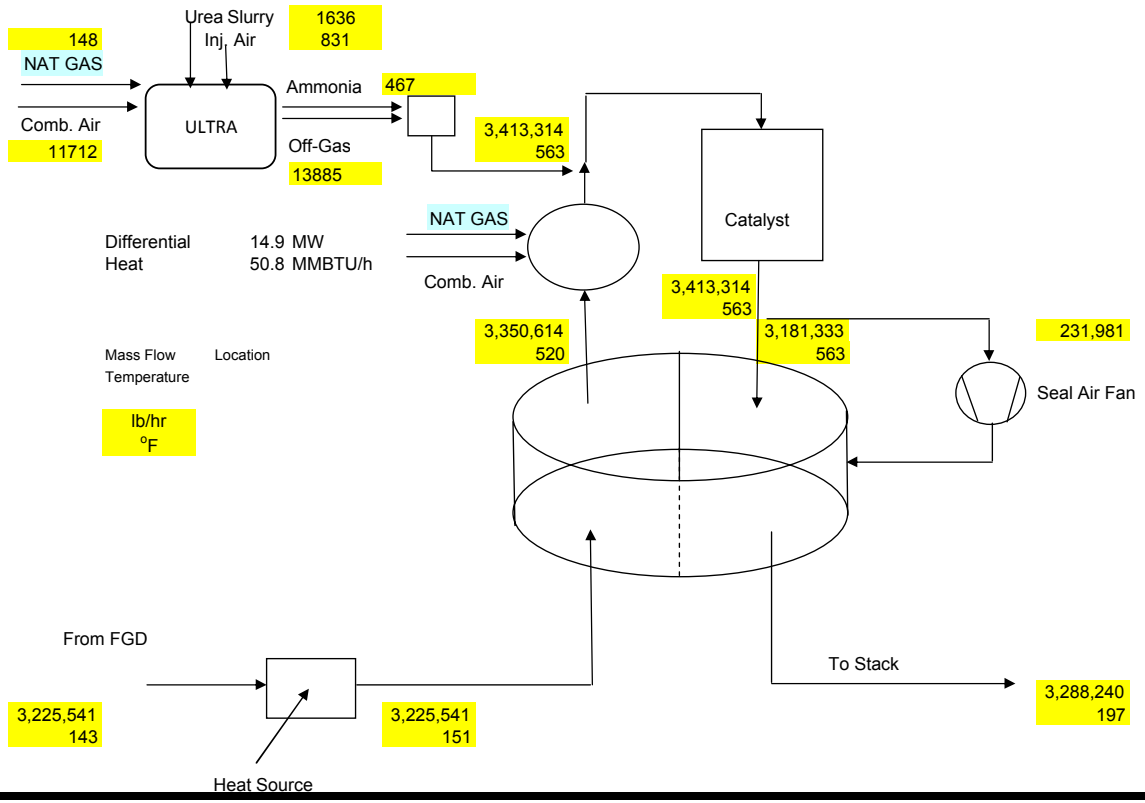
Best Regards, Bob

Robert E. Johnson
Fuel Tech, Inc
(913) 897 0727

This message contains information that may be privileged, confidential or otherwise protected from disclosure. Unless you are the intended addressee (or authorized recipient for the addressee) you may not use, copy or disclose this message or information contained in this message to anyone. If you received this message in error, please notify the sender by replying to this message and then delete it from your system without copying or disclosing it. Thank you.

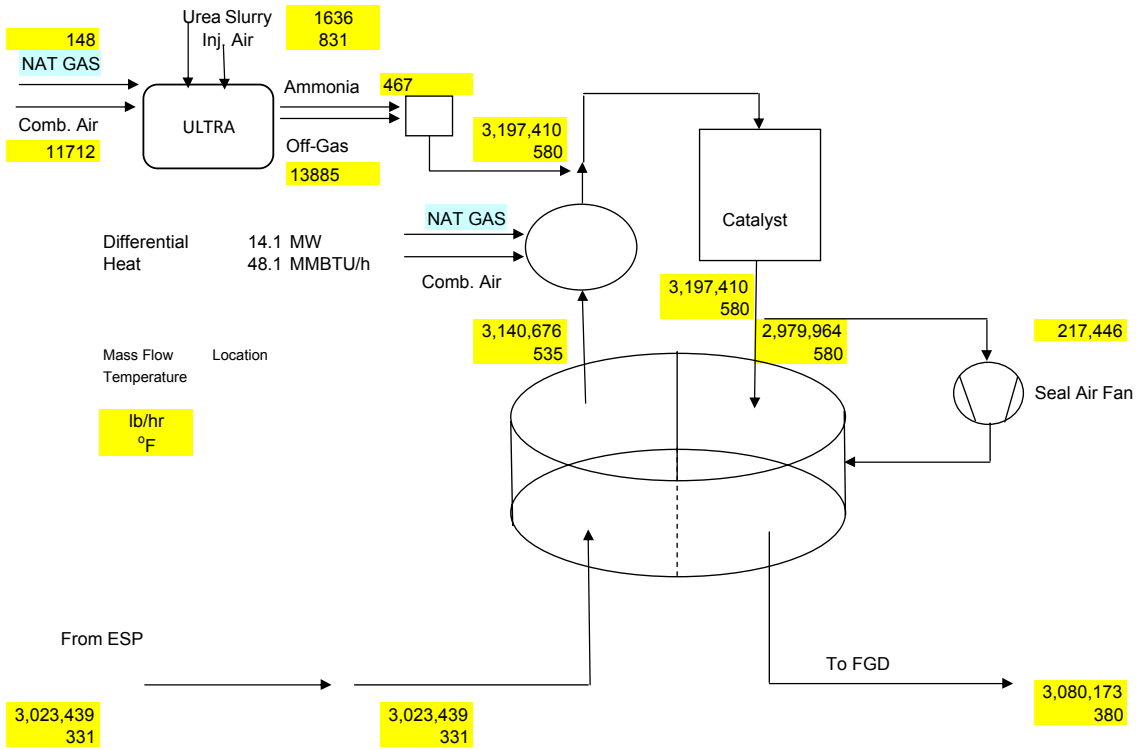
<<11Sep09_MRY2TailEnd_Rev1_natgas.pdf>> <<11Sep09_MRY1LowDust_Rev1_natgas_580F.pdf>>
<<11Sep09_MRY1TailEnd_Rev1_natgas.pdf>> <<11Sep09_MRY2LowDust_Rev1_natgas_580F.pdf>>

MRY 2 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



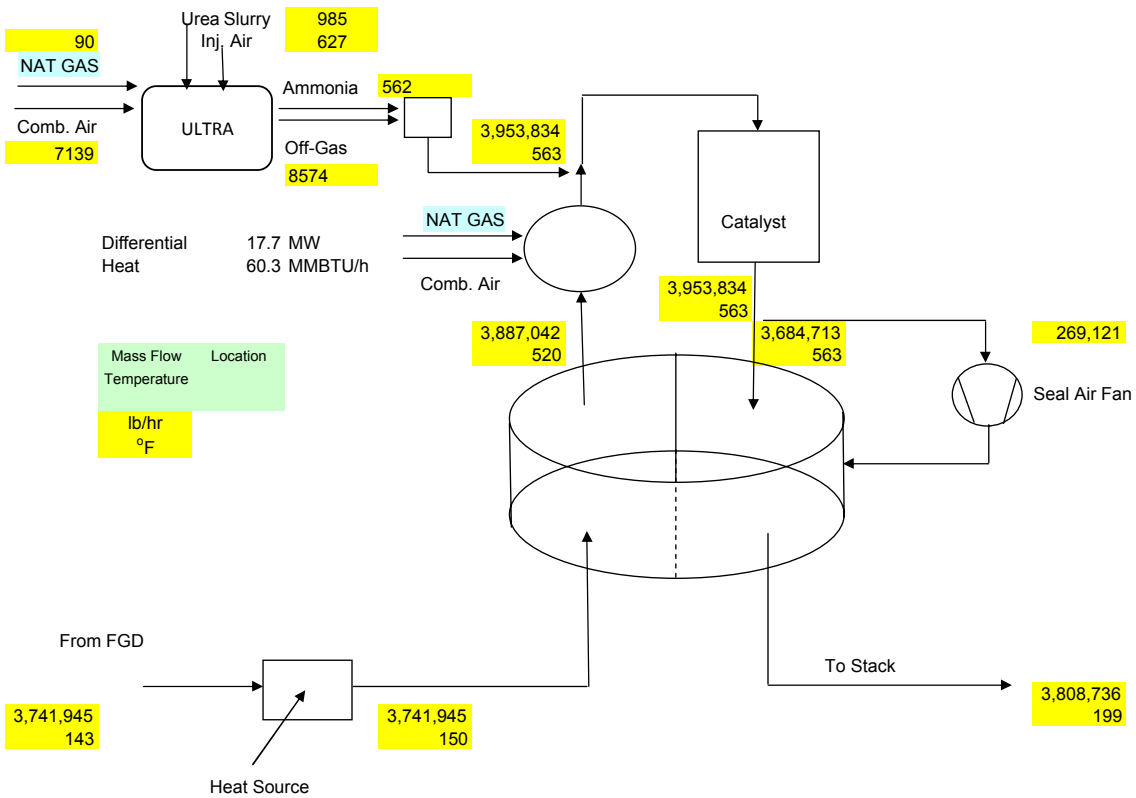
		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Stack
Nitrogen	lb/h	2,063,089	2,063,089	2,143,153	2,180,798	2,190,180	2,191,336	2,042,555	2,073,613
Carbon di oxide	lb/h	542,901	542,901	563,883	569,281	570,295	570,295	531,575	543,915
Oxygen	lb/h	184,328	184,328	191,503	192,324	194,569	194,130	180,949	185,704
Moisture	lb/h	437,137	437,137	454,118	458,657	459,759	460,502	429,236	439,707
Sulfur di oxide	lb/h	496	496	514	514	514	510	475	491
Sulfur tri oxide	lb/h	0	0	0	0	0	6	6	6
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,389	1,389	1,381	1,397	1,397	132	123	139
Argon	lb/h	0	0	8	8	167	167	156	159
Ammonia	lb/h	0	0	0	0	468	5	5	5
Particulate	lb/h	77	77	80	80	80	80	0	77

MRY 2 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



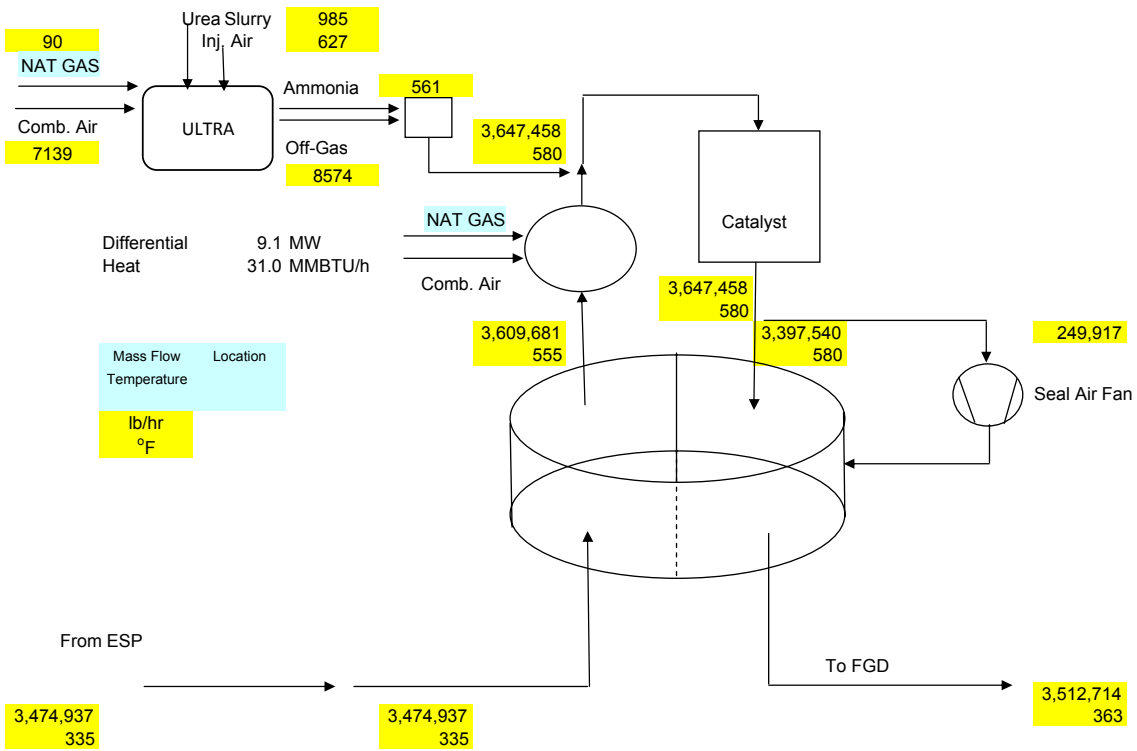
		ESP Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	FGD Inlet
Nitrogen	lb/h	2,031,828	2,031,828	2,110,656	2,143,657	2,153,039	2,154,192	2,007,837	2,042,352
Carbon di oxide	lb/h	536,419	536,419	557,143	561,875	562,889	562,889	524,646	537,433
Oxygen	lb/h	177,258	177,258	184,157	184,877	187,122	186,683	174,000	178,633
Moisture	lb/h	270,167	270,167	280,707	284,686	285,788	286,530	267,063	272,738
Sulfur di oxide	lb/h	9,934	9,934	10,312	10,312	10,312	10,213	9,519	9,835
Sulfur tri oxide	lb/h	0	0	6	6	6	130	121	124
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,389	1,389	1,381	1,395	1,395	132	123	139
Argon	lb/h	0	0	8	8	167	167	156	159
Ammonia	lb/h	0	0	0	0	468	5	4	5
Particulate	lb/h	77	77	80	80	80	80	0	77

MRY 1 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated	Stack
Nitrogen	lb/h	2,371,943	2,371,943	2,463,985	2,508,879	2,514,687	2,516,076	2,344,997	2,379,123
Carbon di oxide	lb/h	622,053	622,053	646,129	652,566	653,180	653,180	608,768	622,667
Oxygen	lb/h	213,652	213,652	221,928	222,907	224,302	223,774	208,558	214,002
Moisture	lb/h	536,485	536,485	557,343	562,756	563,425	564,318	525,948	538,919
Sulfur di oxide	lb/h	568	568	590	590	590	584	545	563
Sulfur tri oxide	lb/h	0	0	0	0	0	7	7	7
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,670	1,670	1,660	1,679	1,679	159	148	167
Argon	lb/h	0	0	5	5	103	103	96	98
Ammonia	lb/h	0	0	0	0	563	6	6	6
Particulate	lb/h	70	70	73	73	73	73	0	70

MRY 1 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



		ESP Outlet	GGH inlet	GGH outlet	Burner out	Catalyst Inlet	Catalyst Outlet	GGH treated inlet	FGD Inlet
Nitrogen	lb/hr	2,336,123	2,336,123	2,426,758	2,449,060	2,454,868	2,456,248	2,288,130	2,343,304
Carbon di oxide	lb/hr	614,626	614,626	638,408	641,606	642,220	642,220	598,263	615,240
Oxygen	lb/hr	205,551	205,551	213,511	213,998	215,393	214,868	200,161	205,901
Moisture	lb/hr	309,692	309,692	321,780	324,469	325,138	326,026	303,711	312,126
Sulfur di oxide	lb/hr	11,381	11,381	11,815	11,815	11,815	11,701	10,901	11,267
Sulfur tri oxide	lb/hr	0	0	7	7	7	149	139	142
Nitrogen oxide	lb/hr	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/hr	1,670	1,670	1,660	1,669	1,669	159	148	167
Argon	lb/hr	0	0	5	5	103	103	96	98
Ammonia	lb/hr	0	0	0	0	562	5	5	5
Particulate	lb/hr	70	70	73	73	73	73	0	70

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Tuesday, September 15, 2009 7:36 AM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: 15Sep09_MRYS Comments

Bob,
Volker and I have prepared the attached comments pertaining to MRYS SCRs.
We'd be glad to discuss at your convenience.
Best Regards, Bob

Robert E. Johnson
Fuel Tech, Inc
(913) 897 0727

This message contains information that may be privileged, confidential or otherwise protected from disclosure. Unless you are the intended addressee (or authorized recipient for the addressee) you may not use, copy or disclose this message or information contained in this message to anyone. If you received this message in error, please notify the sender by replying to this message and then delete it from your system without copying or disclosing it. Thank you.

<<15Sep09_BMcD for MRYS_Comments.pdf>>

Burns & McDonnell for Minnkota Power
Milton Young Station

Low Dust & Tail End Selective Catalytic Reduction (SCR) Systems
Comments

Conceptual Arrangement Drawings

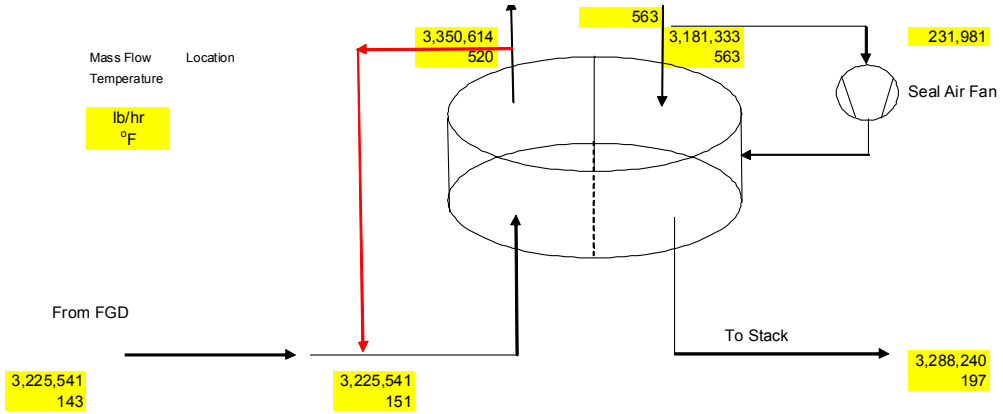
Fuel Tech has reviewed the initial arrangement drawings. Here are our comments:

- Based on what was provided, we don't see anything that could be considered a "fatal flaw."
- In general, there are two design considerations that deserve closer evaluation once we have the opportunity to review 3-D models:
    - Location of bypass dampers and ducts;
    - Duct transitions within the inlet ductwork and into the reactor hood. It is important to maintain uniform ammonia and flue gas distributions into the catalyst, and severe angles and transitions have significant effects.

Flue Gas Heating & FGD GGH Options

For Tail End systems, it is important for the flue gas temperature entering the SCR GGH to be above the water dewpoint. This will prevent condensation and potential corrosion within the GGH. There are a few methods for raising the FGD outlet temperature:

- FGD GGH: Regenerative type heat exchangers have been used in Europe for this application. When FGD systems were deployed in German powerplants, heat exchangers were needed to raise flue gas temperatures to >72°C for plume buoyancy. These same exchangers were integrated into Tail End SCR systems. Some corrosion issues have been documented. Some solutions that have been used include alloy elements, plastic elements, and enameled elements.
- FGD Heat Pipes: Another type of heat exchanger is the heat pipe technology, such as that marketed by Hitachi. Hitachi has installed this type of exchanger in Japanese plants.
- Flue Gas Heating with Duct Burners: Direct gas firing in the duct would eliminate the need for a heat exchanger. In contrast to the use of duct burners for maintaining flue gas temperature to the inlet of the SCR catalyst, continuous gas firing would be needed for controlling the flue gas temperature at the inlet to the SCR GGH.
- Heat Exchange Loop at the SCR GGH: Another method includes the use of a slipstream from the SCR GGH outlet back to the inlet to raise the inlet flue gas temperature. This alternative is shown below in red:



The latter two methods would affect the overall mass balance of the Tail End system, primarily due to the increased natural gas consumption by the duct burners.

A cost-benefit comparison of these alternatives should be prepared specifically for the MRYS installation.

Start Up Procedures

Start up procedures need to be specifically prepared for MRYS based on the final operating permit. In some cases, partial or full bypass of the SCR may be permitted for a certain period to allow the catalyst to be warmed to operating temperature before ammonia injection is permitted to commence. If bypass is not allowed, then other procedural methods will be developed for the MRYS installation.

One alternative is described here. After purging the entire flue gas duct work of the unit, FD and ID fans will ramp up to the highest capacity. The SCR GGH must be in operation. The SCR burners will be turned on to preheat the catalyst to operating temperature. Once this is established, boiler startup can be initiated and the bypass dampers to the SCR can be closed to permit flue gas to flow into the reactor. The reagent for the SCR can be injected immediately after the first fire in the boiler.

Other procedural methods may be developed in conjunction with overall system design, the final selection of a Tail End or Low Dust system, and the final permit for the plant if this kind of preheat is not acceptable.

Catalyst Exchange Information

In practice, catalyst loading, removal and exchange procedures vary widely among the operating SCR plants in the United States. It is our experience that Architect-Engineers, System suppliers, catalyst suppliers and Utilities have assimilated “best practices” and have developed site specific procedures. Unfortunately, we are unaware of specific and published comparisons or time & motion studies that document actual experience.

Fuel Tech knows specific procedures for some of our clients and we are aware of their experiences. In our opinion, it is not appropriate to use these particular experiences to validate other experiences or catalyst handling designs within the industry.

To achieve a specific requirement, such as a complete catalyst layer exchange within a certain period, the complete SCR system must be designed to accommodate this. For instance, catalyst module handling, storage, and movement must be consistent with the reactor platforms, access door number and location, catalyst transport systems from storage to platform, handling within the reactor and the number of personnel and shifts to perform the exchange.

Our "rule of thumb" estimate for catalyst installation is thirty (30) minutes per module. This is based on conventional access, use of hoists for module handling and transport, and a typical crew of 4 to 6 people. With a different system design and more personnel, the time period can certainly be reduced.

Catalyst Slipstream Test

Concerning the budgetary estimate and schedule for a comprehensive slipstream test, we suggest the following:

- The test should include a reactor large enough to house multiple catalyst types and layers;
- The test should run preferably nine (9) months to a year, in order to observe effects on the catalyst;
- An independent lab should be used to evaluate all of the catalysts at various intervals to develop trends;
- The operation of the test reactor needs to be monitored throughout the duration of the test for proper correlation of catalyst effects with flow and temperature.

Without specific details or requirements, we estimate the cost to design, build and install the test reactor to range from $400,000 to $600,000. Testing, operating and monitoring the program is estimated to cost $250,000 to $400,000 depending on the duration and final program.

Blakley, Robert

From: Blakley, Robert
Sent: Tuesday, September 15, 2009 9:18 AM
To: Robert Johnson
Cc: 51684; Bryant, Ronald; Volker Rummenhohl; Loehr, Zachary
Subject: FW: Fuel Tech Flow Diagram Discrepancy
Attachments: Fuel Tech Comparison.xls; Sep09_MRY1LowDust_Rev0_PFD.pdf; Sep09_MRY1TailEnd_Rev0_PFD.pdf; Sep09_MRY2LowDust_Rev0_PFD.pdf; Sep09_MRY2TailEnd_Rev0_PFD.pdf

Bob -

Please confirm the urea consumption rates and natural gas consumption for flue gas reheating recently provided for Unit 1 low-dust and tail-end SCRs.
These are for a single SCR reactor for Unit 1 in each of the two configurations.

Also advise on the status of the updated preliminary mass balance calculations for all 4 cases.

Let us know if questions arise.

Thanks for the comments on your review of our preliminary SCR arrangements. We will review and advise if we want additional comments that you may be able to provide.

Bob Blakley

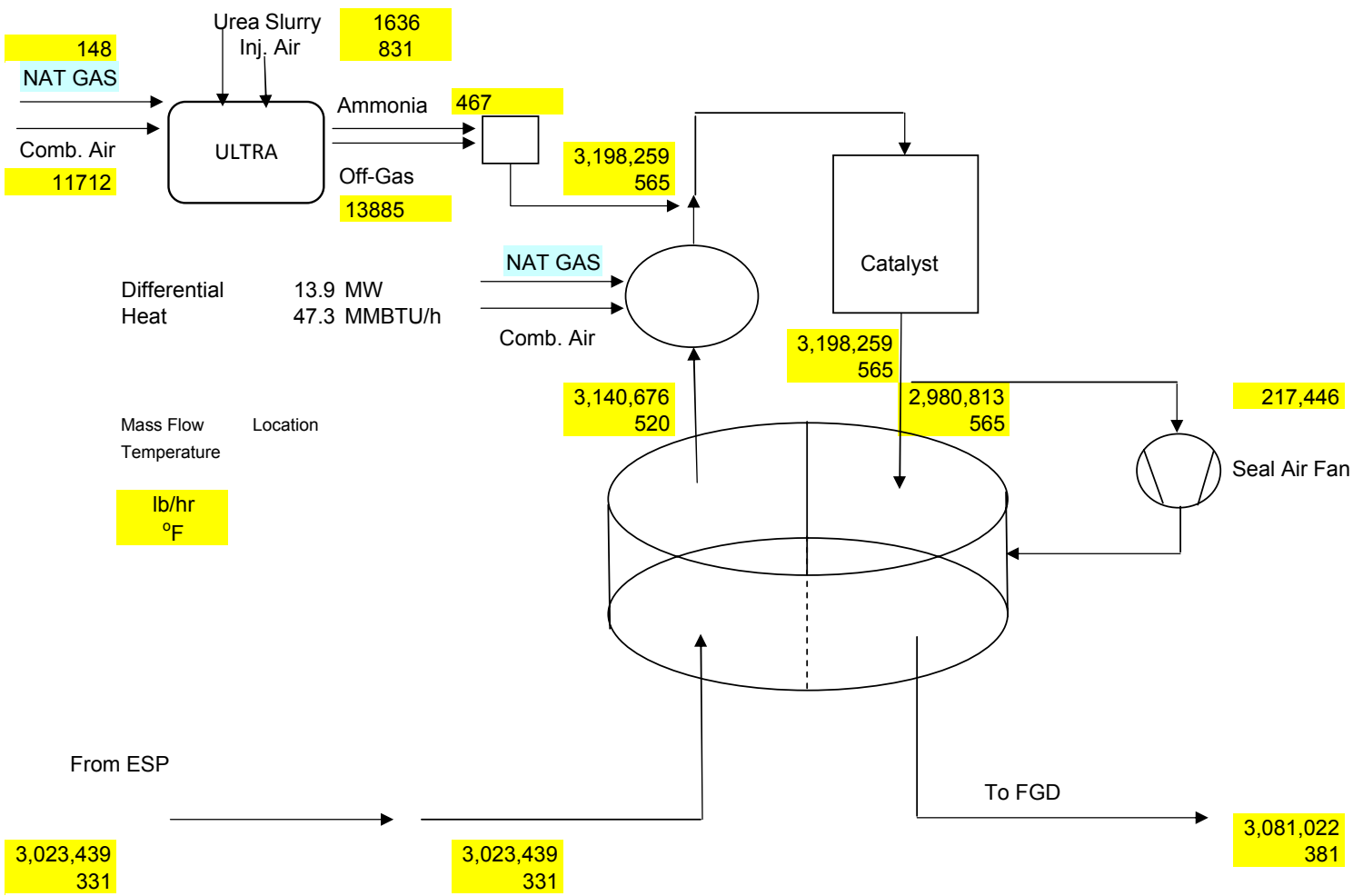
From: Loehr, Zachary
Sent: Friday, September 11, 2009 9:49 AM
To: Blakley, Robert
Cc: Blackwood, Dave; Bryant, Ronald
Subject: Fuel Tech Flow Diagram Discrepancy

Robert,
I was reviewing the Fuel Tech flow diagrams to pull the urea and natural gas usages for the economic evaluation. I found that some of the numbers aren't adding up. If you compare the Sept 09 flow diagrams vs the March 09 diagrams, the urea and natural gas usages look off for the Unit 1 Tail End and Low Dust options. The ammonia values match fairly closely though. It looks like they may have forgotten that the March 09 numbers were based on two reactors while the Sept 09 numbers where only based on one reactor. The urea and natural gas numbers are half of what they should be. Attached is a spreadsheet that compares the two sets of data. Please verify this with Fuel Tech.
Thanks,

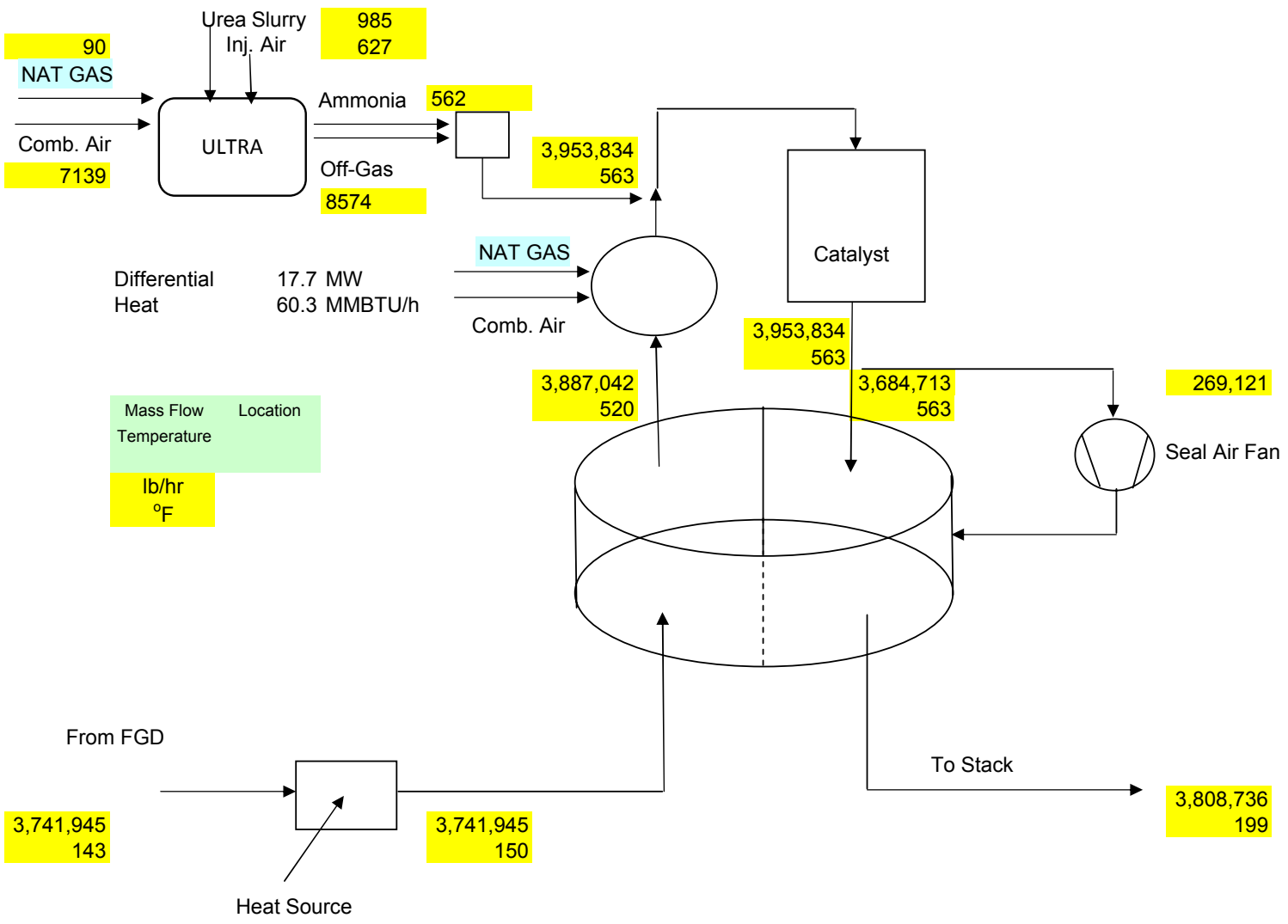
Zac Loehr
Development Engineer, Energy Group
Burns & McDonnell
9400 Ward Parkway
Kansas City, MO 64114
Main: 816-333-9400
Fax: 816-333-3690
www.burnsmcd.com

Proud to be one of FORTUNE's 100 Best Companies To Work For
Please consider the environment before printing this e-mail.

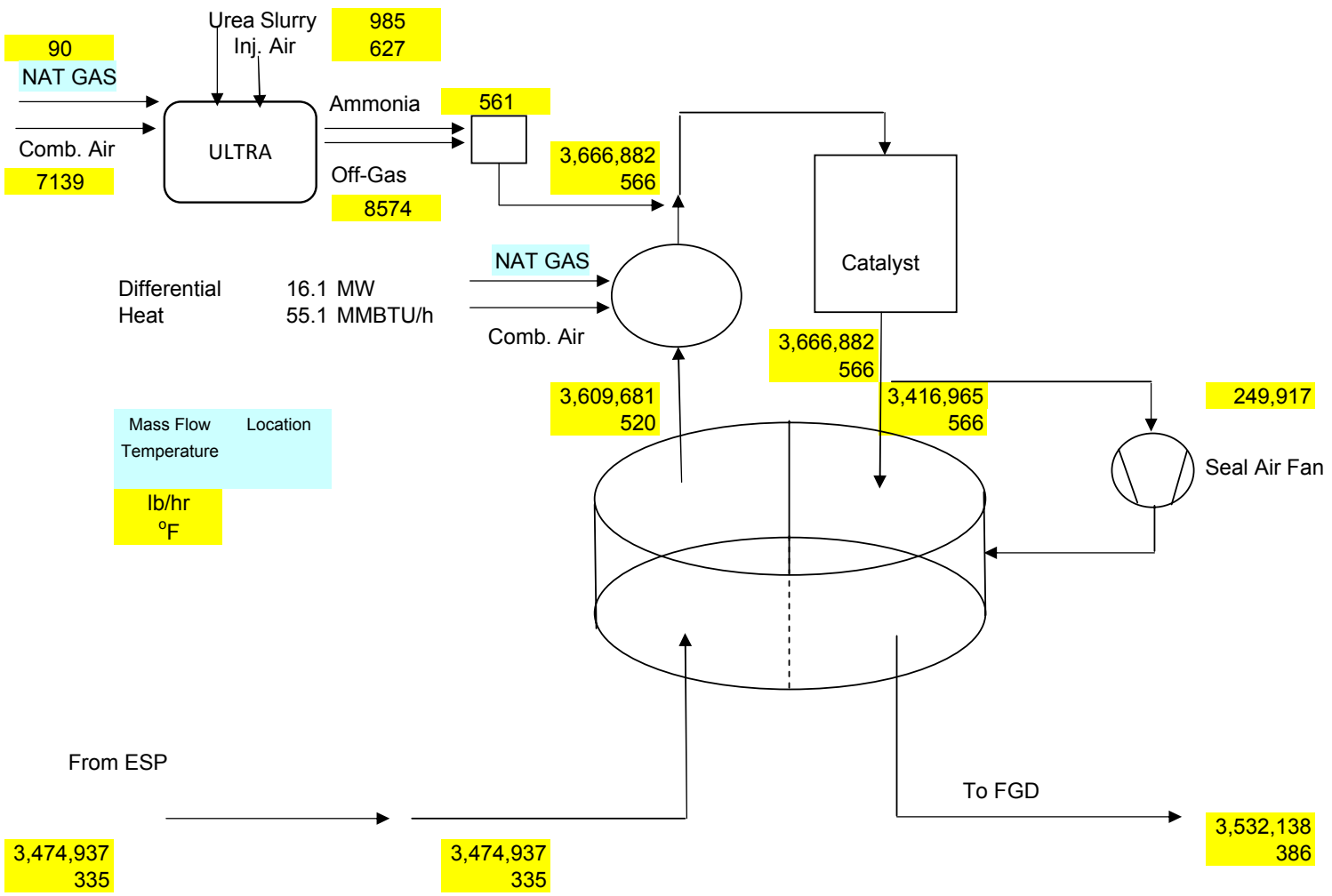
MRY 2 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



MRY 1 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



MRY 1 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



March, 2009

Low Dust

	Urea	Ammonia	NG		Am/Ur	Gas Flow lb/hr
Unit 1	1972	530	180	lb/hr	0.268763	3,680,676
Unit 2	3276	884	296	lb/hr	0.269841	6,402,446
Total	5248	1414	476	lb/hr		

Tail End

	Urea	Ammonia	NG		Am/Ur	Gas Flow lb/hr
Unit 1	1972	532	180	lb/hr	0.269777	3,964,412
Unit 2	3276	884	296	lb/hr	0.269841	6,832,108
Total	5248	1416	476	lb/hr		

September, 2009

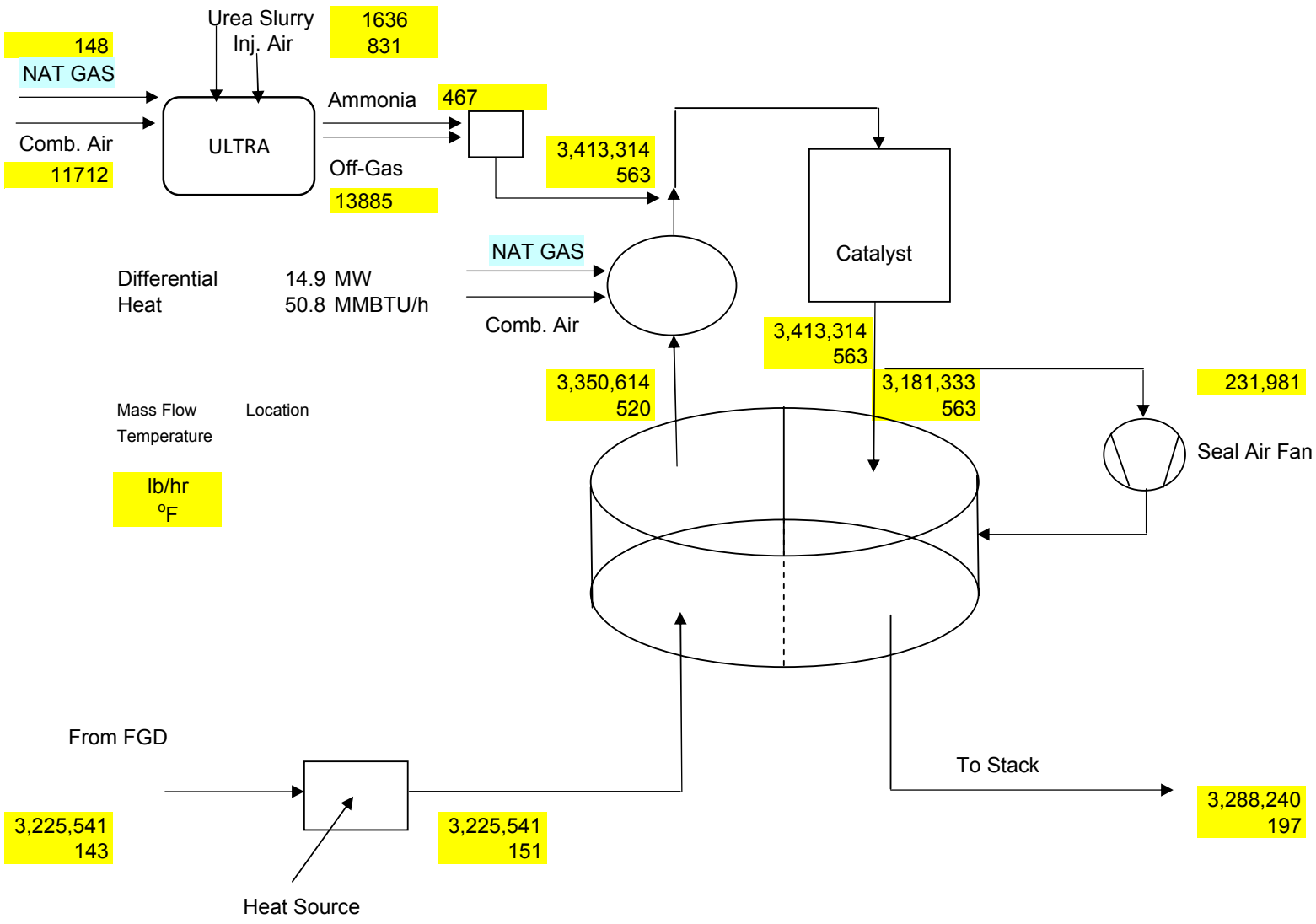
Low Dust

	Urea	Ammonia	NG		Am/Ur	Gas Flow lb/hr
Unit 1	985	561	90	lb/hr	0.569543	3,666,882
Unit 2	3272	934	296	lb/hr	0.285452	6,396,518
Total	4257	1495	386	lb/hr		

Tail End

	Urea	Ammonia	NG		Am/Ur	Gas Flow lb/hr
Unit 1	985	562	90	lb/hr	0.570558	3,953,834
Unit 2	3272	934	296	lb/hr	0.285452	6,826,628
Total	4257	1496	386	lb/hr		

MRY 2 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



Blakley, Robert

From: Robert Johnson [RJohnson@ftek.com]
Sent: Tuesday, September 15, 2009 9:53 AM
To: Blakley, Robert
Cc: 51684; Bryant, Ronald; Volker Rummenhohl; Loehr, Zachary
Subject: RE: Fuel Tech Flow Diagram Discrepancy

Bob,
Thanks for picking up the discrepancy.
yes, we overlooked the linkage between sheets in the file.
We'll revise and re-issue for U1 TE and LD.
Bob

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Tuesday, September 15, 2009 9:18 AM
To: Robert Johnson
Cc: 51684; Bryant, Ronald; Volker Rummenhohl; Loehr, Zachary
Subject: FW: Fuel Tech Flow Diagram Discrepancy

Bob -

Please confirm the urea consumption rates and natural gas consumption for flue gas reheating recently provided for Unit 1 low-dust and tail-end SCRs.
These are for a single SCR reactor for Unit 1 in each of the two configurations.

Also advise on the status of the updated preliminary mass balance calculations for all 4 cases.

Let us know if questions arise.

Thanks for the comments on your review of our preliminary SCR arrangements. We will review and advise if we want additional comments that you may be able to provide.

Bob Blakley

From: Loehr, Zachary
Sent: Friday, September 11, 2009 9:49 AM
To: Blakley, Robert
Cc: Blackwood, Dave; Bryant, Ronald
Subject: Fuel Tech Flow Diagram Discrepancy

Robert,
I was reviewing the Fuel Tech flow diagrams to pull the urea and natural gas usages for the economic evaluation. I found that some of the numbers aren't adding up. If you compare the Sept 09 flow diagrams vs the March 09 diagrams, the urea and natural gas usages look off for the Unit 1 Tail End and Low Dust options. The ammonia values match fairly closely though. It looks like they may have forgotten that the March 09 numbers were based on two reactors while the Sept 09 numbers where only based on one reactor. The urea and natural gas numbers are half of what they should be. Attached is a spreadsheet that compares the two sets of data. Please verify this with Fuel Tech.
Thanks,

Zac Loehr
Development Engineer, Energy Group
Burns & McDonnell

9400 Ward Parkway
Kansas City, MO 64114
Main: 816-333-9400
Fax: 816-333-3690
www.burnsmcd.com

Proud to be one of FORTUNE's 100 Best Companies To Work For
Please consider the environment before printing this e-mail.

Blakley, Robert

From: Blakley, Robert
Sent: Thursday, September 17, 2009 11:16 AM
To: Robert Johnson
Cc: 51684; Bryant, Ronald; Volker Rummenhohl; Loehr, Zachary
Subject: RE: Fuel Tech Flow Diagram and Mass Balanace Updates

Bob -

When updating the preliminary process flow diagrams and mass balance calculations, can you provide more information on:

1. flue gas reheat natural gas fuel consumption in million Btu/hr and SCFH in addition to mass flow (lb/hr)?

2. percent excess air and mass flow (lb/hr) of ambient combustion air assumed for the reheat burner natural gas firing?

3. FTI's ULTRA urea-to-ammonia system urea versus ambient dilution air mass flows (lb/hr)?

4. FTI's ULTRA urea-to-ammonia system natural gas fuel consumption in million Btu/hr and SCFH, and how much of the ambient dilution air is used in the combustion of the natural gas?

We are interested in also knowing the amount of NOx expected to be produced by the flue gas reheat natural gas firing and if the ULTRA conversion system's NOx is a significant quantity that the SCR reactor catalyst has to remove by reaction with ammonia.

It would also be beneficial to know if the amount of natural gas consumed (million Btu/hr) and NOx produced (lb/mmBtu) by the flue gas reheat natural gas firing ahead of the SCR reactors for what amount of time during system startup is higher than the steady-state rates which are shown in the preliminary PFDs/ mass balances. Our interest is whether this firing has substantially greater rates to shorten the amount of time for ramp-up of the gas temperature into the reactor and subsequent ability to start the boiler coal-firing period. This will help us include this in our economic and BACT analysis studies.

We realize that the design basis of the Fuel Tech ULTRA systems recently provided (by Julie Higgins) with budgetary pricing is slightly different than that for the SCRs' design basis, i.e. slightly higher inlet NOx lb/mmBtu, lower NOx removal percentage. This is acceptable, as we can assume the numbers you provide for the SCRs and know that the ULTRA proposal design basis numbers are slightly higher so we have a conservative approach, i.e. built-in capacity margin above maximum expected demand.

Thanks,

Bob Blakley

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Tuesday, September 15, 2009 9:53 AM
To: Blakley, Robert
Cc: 51684; Bryant, Ronald; Volker Rummenhohl; Loehr, Zachary
Subject: RE: Fuel Tech Flow Diagram Discrepancy

Bob,
Thanks for picking up the discrepancy.
yes, we overlooked the linkage between sheets in the file.
We'll revise and re-issue for U1 TE and LD.
Bob

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Tuesday, September 15, 2009 9:18 AM
To: Robert Johnson
Cc: 51684; Bryant, Ronald; Volker Rummenhohl; Loehr, Zachary
Subject: FW: Fuel Tech Flow Diagram Discrepancy

Bob -

Please confirm the urea consumption rates and natural gas consumption for flue gas reheating recently provided for Unit 1 low-dust and tail-end SCRs.
These are for a single SCR reactor for Unit 1 in each of the two configurations.

Also advise on the status of the updated preliminary mass balance calculations for all 4 cases.

Let us know if questions arise.

Thanks for the comments on your review of our preliminary SCR arrangements. We will review and advise if we want additional comments that you may be able to provide.

Bob Blakley

From: Loehr, Zachary
Sent: Friday, September 11, 2009 9:49 AM
To: Blakley, Robert
Cc: Blackwood, Dave; Bryant, Ronald
Subject: Fuel Tech Flow Diagram Discrepancy

Robert,
I was reviewing the Fuel Tech flow diagrams to pull the urea and natural gas usages for the economic evaluation. I found that some of the numbers aren't adding up. If you compare the Sept 09 flow diagrams vs the March 09 diagrams, the urea and natural gas usages look off for the Unit 1 Tail End and Low Dust options. The ammonia values match fairly closely though. It looks like they may have forgotten that the March 09 numbers were based on two reactors while the Sept 09 numbers where only based on one reactor. The urea and natural gas numbers are half of what they should be. Attached is a spreadsheet that compares the two sets of data. Please verify this with Fuel Tech.
Thanks,

Zac Loehr
Development Engineer, Energy Group
Burns & McDonnell
9400 Ward Parkway
Kansas City, MO 64114
Main: 816-333-9400
Fax: 816-333-3690
www.burnsmcd.com

Proud to be one of FORTUNE's 100 Best Companies To Work For
Please consider the environment before printing this e-mail.

Blakley, Robert

From: Robert Johnson [RJohnson@ftek.com]
Sent: Tuesday, September 22, 2009 11:57 PM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: 22Sep_MRYS Additional Data & Revised PFDs
Attachments: 22Sep09_MRY1TailEnd_Rev2_natgas.pdf; 22Sep09_BMcD for MRYS_Additional Process Data.pdf; 22Sep09_MRY1LowDust_Rev2_natgas_580F.pdf

Bob,
Attached are the revised PFDs for Unit 1 to reflect the single reactor.
Also attached is the summary of data you requested last Thursday.

At this time, we have not estimated the natural gas consumption during startup. This is in part a function of the GGH design and the specific startup procedure. Volker and I will discuss and see if we can provide some context.

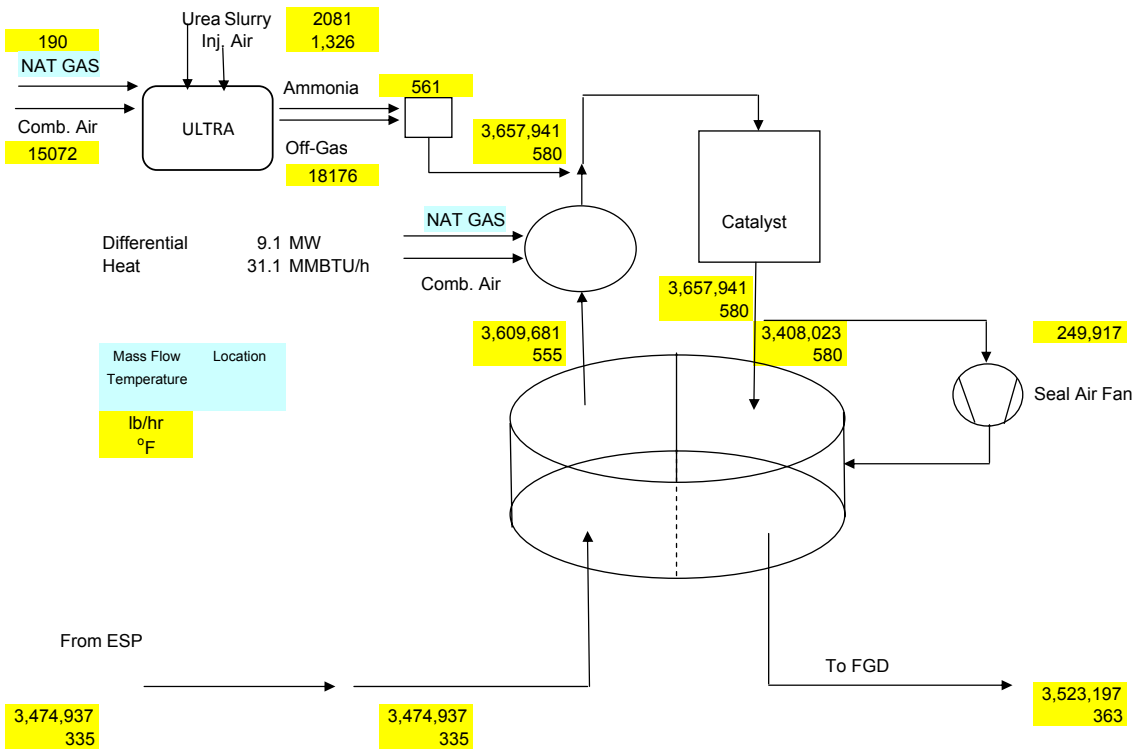
Please let us know if we can clarify anything.
Best Regards,
Bob

Robert E. Johnson
Fuel Tech, Inc
(913) 897 0727

This message contains information that may be privileged, confidential or otherwise protected from disclosure. Unless you are the intended addressee (or authorized recipient for the addressee) you may not use, copy or disclose this message or information contained in this message to anyone. If you received this message in error, please notify the sender by replying to this message and then delete it from your system without copying or disclosing it. Thank you.

<<22Sep09_MRY1TailEnd_Rev2_natgas.pdf>> <<22Sep09_BMcD for MRYS_Additional Process Data.pdf>> <<22Sep09_MRY1LowDust_Rev2_natgas_580F.pdf>>

MRY 1 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



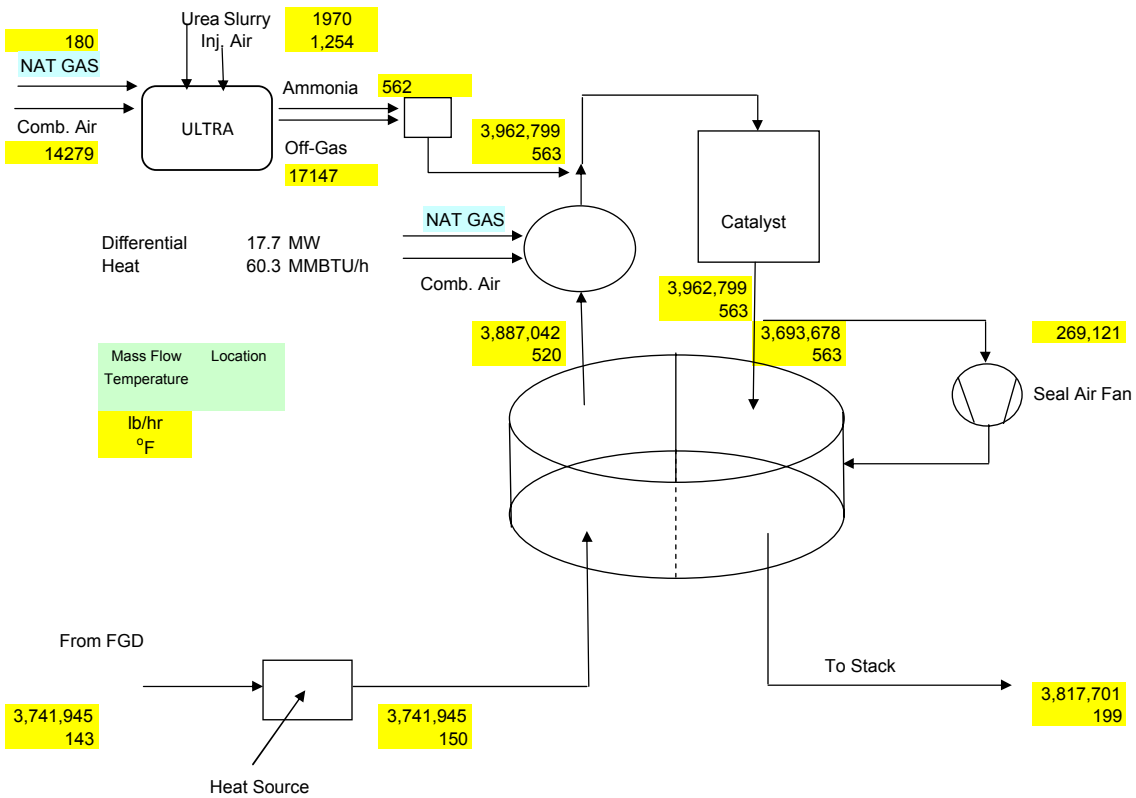
		ESP Outlet	GGH inlet	GGH outlet	Burner out	Catalyst Inlet	Catalyst Outlet	GGH treated	FGD Inlet
Nitrogen	lb/hr	2,336,123	2,336,123	2,426,760	2,449,748	2,462,061	2,463,441	2,295,314	2,349,809
Carbon di oxide	lb/hr	614,626	614,626	638,358	641,655	642,957	642,957	599,076	615,928
Oxygen	lb/hr	205,551	205,551	213,561	214,062	217,019	216,494	201,718	207,463
Moisture	lb/hr	309,692	309,692	321,775	324,547	325,965	326,852	304,545	312,875
Sulfur di oxide	lb/hr	11,381	11,381	11,814	11,814	11,814	11,700	10,901	11,267
Sulfur tri oxide	lb/hr	0	0	7	7	7	149	139	142
Nitrogen oxide	lb/hr	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/hr	1,670	1,670	1,660	1,670	1,670	159	148	167
Argon	lb/hr	0	0	10	10	218	218	203	208
Ammonia	lb/hr	0	0	0	0	562	5	5	5
Particulate	lb/hr	70	70	73	73	73	73	0	70

Burns & McDonnell for Minnkota Power
Milton Young Station

Low Dust & Tail End Selective Catalytic Reduction (SCR) Systems
Additional Mass Balance Data

		Unit 1 Low Dust	Unit 1 Tail End	Unit 2 Low Dust	Unit 2 Tail End
Reheat Natural Gas	MMBtu/hr	30	33	43.1	49.2
Reheat Natural Gas	scfm	491	965	704	803
Burner System	% Air				
Burner System	Air Lb/hr	28,221	55,490	40,514	46,216
ULTRA System Natural Gas	MMBtu/hr	4.27	4.04	3.33	3.33
ULTRA System Natural Gas	scfm	70	66	54	54
NOx Reheat Natural Gas	Lb/hr	5	9	6	7
NOx ULTRA Natural Gas	Lb/hr	1.5	1.5	1.1	1.1
Reactor Total Efficiency	%	90.49	90.54	90.53	90

MRY 1 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated	Stack
Nitrogen	lb/h	2,371,943	2,371,943	2,464,003	2,509,202	2,520,818	2,522,207	2,351,099	2,384,931
Carbon di oxide	lb/h	622,053	622,053	646,089	652,570	653,798	653,798	609,444	623,281
Oxygen	lb/h	213,652	213,652	221,973	222,959	225,749	225,220	209,941	215,397
Moisture	lb/h	536,485	536,485	557,315	562,765	564,103	564,996	526,667	539,588
Sulfur di oxide	lb/h	568	568	590	590	590	584	545	563
Sulfur tri oxide	lb/h	0	0	0	0	0	7	7	7
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,670	1,670	1,660	1,679	1,679	159	148	167
Argon	lb/h	0	0	10	10	206	206	192	196
Ammonia	lb/h	0	0	0	0	563	6	6	6
Particulate	lb/h	70	70	73	73	73	73	0	70

Blakley, Robert

From: Blakley, Robert
Sent: Wednesday, September 23, 2009 4:51 PM
To: Robert Johnson
Cc: 51684; Volker Rummenhohl; Weilert, Carl; Bryant, Ronald; Loehr, Zachary
Subject: FW: 22Sep_MRYS Additional Data & Revised PFDs
Attachments: 22Sep09_MRY1TailEnd_Rev2_natgas.pdf; 22Sep09_BMcD for MRYS_Additional Process Data.pdf; 22Sep09_MRY1LowDust_Rev2_natgas_580F.pdf; 11Sep09_MRY2LowDust_Rev1_natgas_580F.pdf; 11Sep09_MRY2TailEnd_Rev1_natgas.pdf; 11Sep09_MRY1TailEnd_Rev1_natgas.pdf; 11Sep09_MRY1LowDust_Rev1_natgas_580F.pdf

Bob -

We have discovered several inconsistencies that we need you to confirm and/or clarify, as noted in the email below. I have not independently verified the natural gas heat inputs for the flue gas reheating that Zac has provided in the tables for Unit 2 from September 11th PFDs. My numbers below are different for Unit 2 "differential heat" gas consumption inputs.

We also note that the updated flue gas reheat mMMBtu/hr numbers provided in the summary table included in your 9/22/09 email do not match the values shown on the individual process flow diagrams and preliminary mass balance calculations:

		Unit 1 Low Dust	Unit 1 Tail End	Unit 2 Low Dust	U Tai
Reheat Natural Gas	MMBtu/hr	30	33	43.1	4
9/22 PFD	MM Btu/hr	31.1	60.3		
9/11 PFD	MM Btu/hr			48.1	50.8

Please review and let us know promptly with your findings and any corrections needed. We are trying to wrap this up for submittal to Minnkota next week.

Bob Blakley

From: Loehr, Zachary
Sent: Wednesday, September 23, 2009 3:28 PM
To: Blakley, Robert; Blackwood, Dave
Cc: 51684; Bryant, Ronald; Phillips, John; Durant, Bryan; Root, Arlen; Weilert, Carl
Subject: RE: 22Sep_MRYS Additional Data & Revised PFDs

Bob,
There are some additional discrepancies in the documents attached. The NG and Urea rates are now different between the Unit 1 Low Dust and Tail End options. The NG and Urea flow rates for the U1 Tail End case is 180 and 1970 lb/hr respectively. The NG and Urea flow rates for the U1 Low Dust case is 190 and 2081 lb/hr respectively. The rates for both U1 options should be the same. The U1 Tail End case is the same as previous PFD's so I would assume that the Low Dust case is incorrect.

Also, NG usage rates presented in the Additional Mass Balance Data table are different than what was shown in the previous PFD's. See the comparison below. The lb/hr rates look very odd and the lb/MMbtu rates are different that the previous PFD's.

22-Sep

U-A System			
Low Dust		Tail End	
Unit 1	1.5 lb/hr	Unit 1	1.5 lb/hr
Unit 2	1.1 lb/hr	Unit 2	1.1 lb/hr
Total	2.6 lb/hr	Total	2.6 lb/hr

Flue Gas Heating			
Low Dust		Tail End	
Unit 1	30 MMBtu/hr	Unit 1	33 MMBtu/hr
Unit 2	43.1 MMBtu/hr	Unit 2	49.2 MMBtu/hr
Total	73.1 MMBtu/hr	Total	82.2 MMBtu/hr

11-Sep

U-A System			
Low Dust		Tail End	
Unit 1	180 lb/hr	Unit 1	180 lb/hr
Unit 2	296 lb/hr	Unit 2	296 lb/hr
Total	476 lb/hr	Total	476 lb/hr

Flue Gas Heating			
Low Dust		Tail End	
Unit 1	16.1 MMBtu/hr	Unit 1	17.7 MMBtu/hr
Unit 2	47.3 MMBtu/hr	Unit 2	50.8 MMBtu/hr
Total	63.4 MMBtu/hr	Total	68.5 MMBtu/hr

Please have Fuel Tech verify which values are correct.
Zac

From: Blakley, Robert
Sent: Wednesday, September 23, 2009 8:07 AM
To: Blackwood, Dave
Cc: 51684; Bryant, Ronald; Phillips, John; Loehr, Zachary; Durant, Bryan; Root, Arlen; Weilert, Carl
Subject: FW: 22Sep_MRYS Additional Data & Revised PFDs

All -

Here are the updated preliminary process flow diagrams with abbreviated mass balance calculations of Unit 1.
Unit 2's updates were previously provided on Sept. 11.

Please advise if additional information is desired.

Bob Blakley

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Tuesday, September 22, 2009 11:57 PM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: 22Sep_MRYS Additional Data & Revised PFDs

Bob,
Attached are the revised PFDs for Unit 1 to reflect the single reactor.
Also attached is the summary of data you requested last Thursday.

At this time, we have not estimated the natural gas consumption during startup. This is in part a function of the GGH design and the specific startup procedure. Volker and I will discuss and see if we can provide some context.

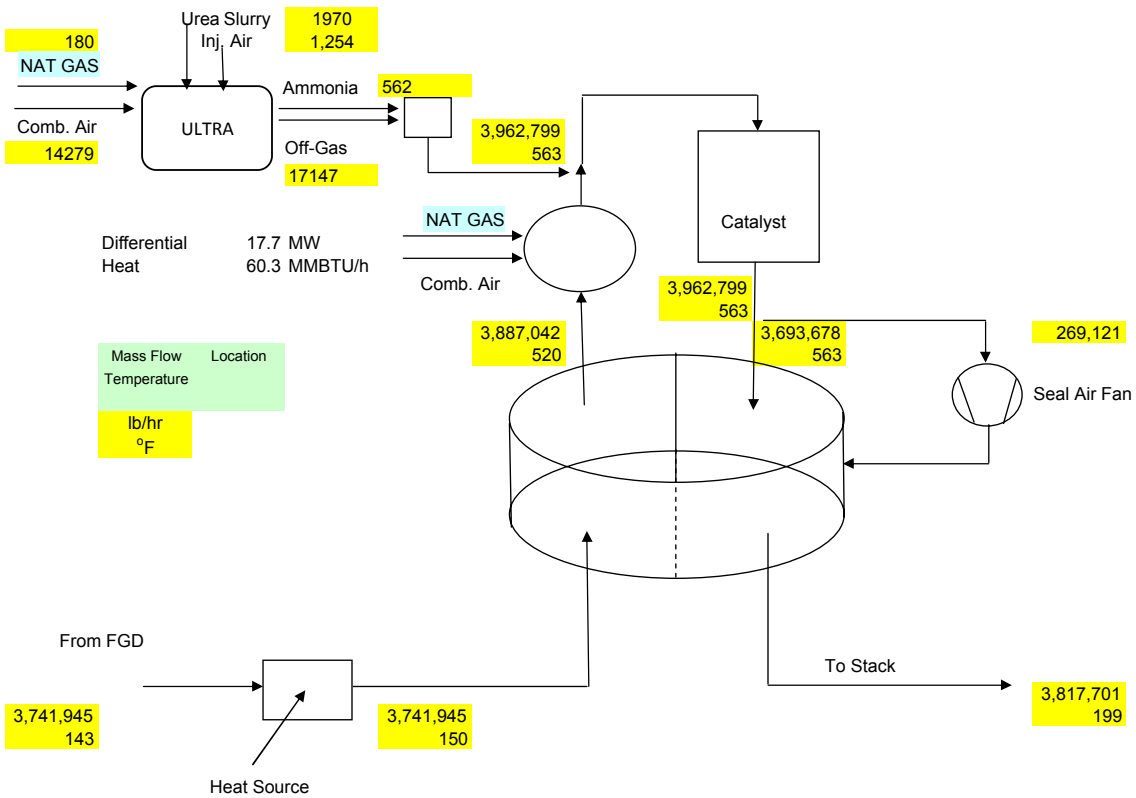
Please let us know if we can clarify anything.
Best Regards,
Bob

Robert E. Johnson
Fuel Tech, Inc
(913) 897 0727

This message contains information that may be privileged, confidential or otherwise protected from disclosure. Unless you are the intended addressee (or authorized recipient for the addressee) you may not use, copy or disclose this message or information contained in this message to anyone. If you received this message in error, please notify the sender by replying to this message and then delete it from your system without copying or disclosing it. Thank you.

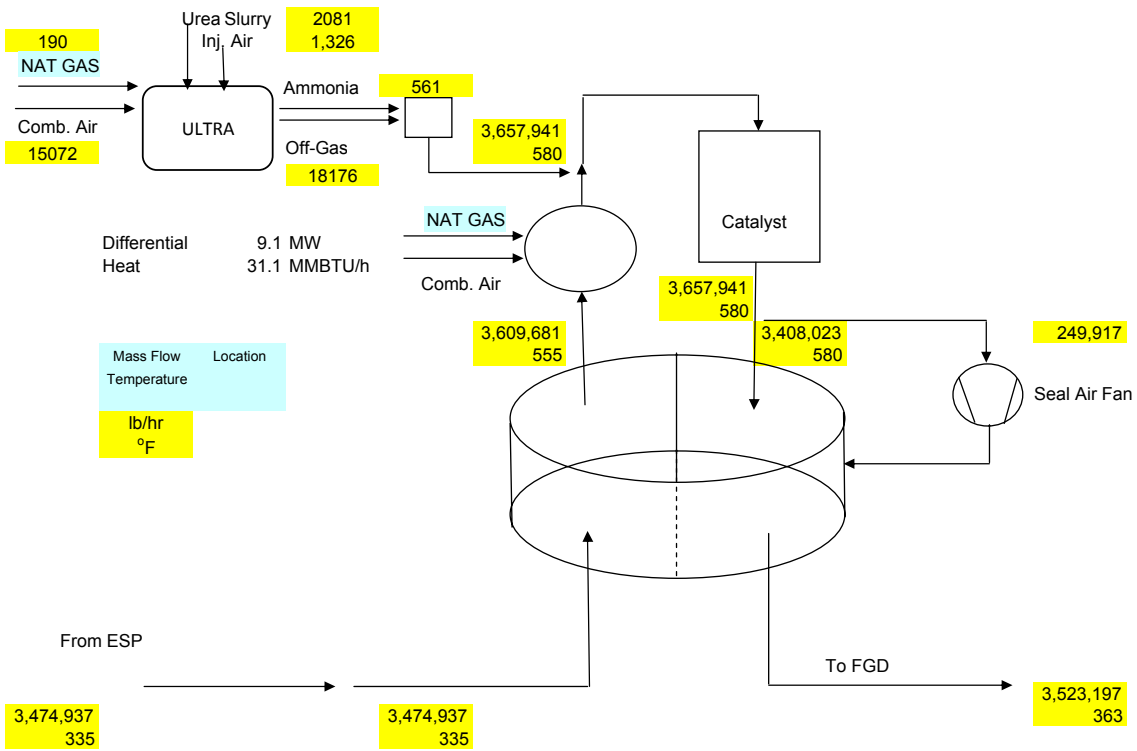
<<22Sep09_MRY1TailEnd_Rev2_natgas.pdf>> <<22Sep09_BMcD for MRYS_Additional Process Data.pdf>> <<22Sep09_MRY1LowDust_Rev2_natgas_580F.pdf>>

MRY 1 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated	Stack
Nitrogen	lb/h	2,371,943	2,371,943	2,464,003	2,509,202	2,520,818	2,522,207	2,351,099	2,384,931
Carbon di oxide	lb/h	622,053	622,053	646,089	652,570	653,798	653,798	609,444	623,281
Oxygen	lb/h	213,652	213,652	221,973	222,959	225,749	225,220	209,941	215,397
Moisture	lb/h	536,485	536,485	557,315	562,765	564,103	564,996	526,667	539,588
Sulfur di oxide	lb/h	568	568	590	590	590	584	545	563
Sulfur tri oxide	lb/h	0	0	0	0	0	7	7	7
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,670	1,670	1,660	1,679	1,679	159	148	167
Argon	lb/h	0	0	10	10	206	206	192	196
Ammonia	lb/h	0	0	0	0	563	6	6	6
Particulate	lb/h	70	70	73	73	73	73	0	70

MRY 1 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



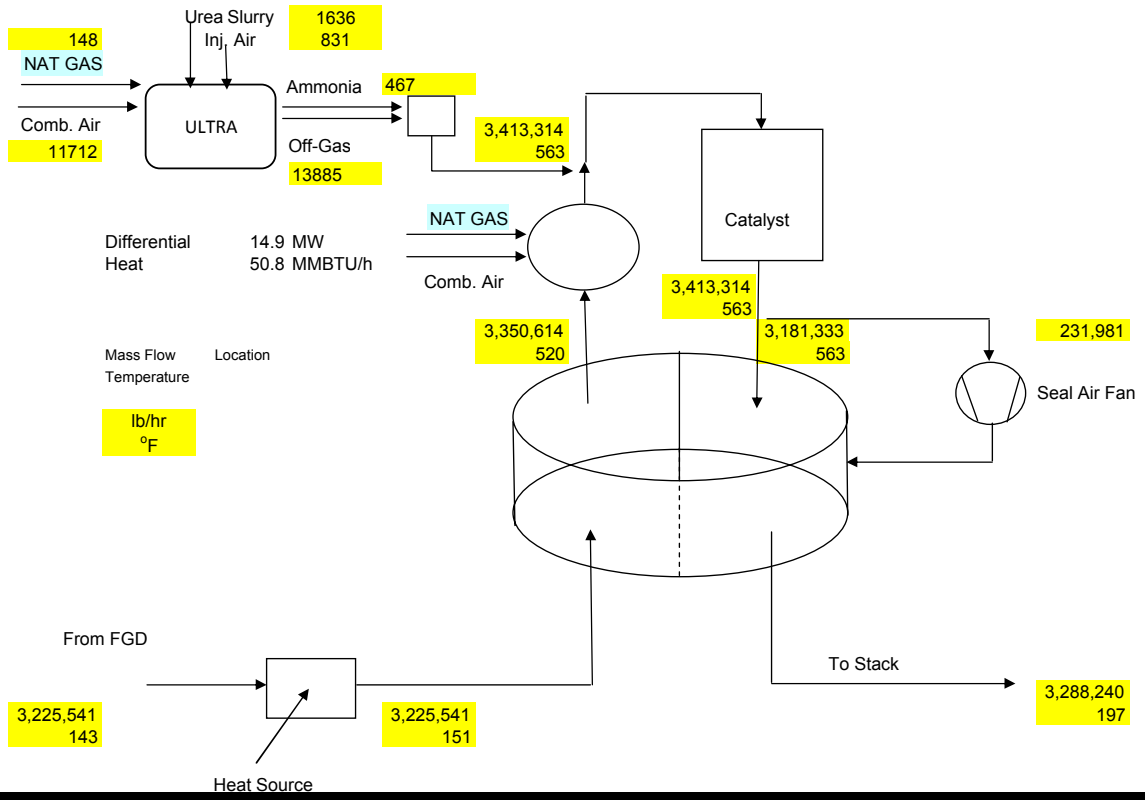
		ESP Outlet	GGH inlet	GGH outlet	Burner out	Catalyst Inlet	Catalyst Outlet	GGH treated	FGD Inlet
Nitrogen	lb/hr	2,336,123	2,336,123	2,426,760	2,449,748	2,462,061	2,463,441	2,295,314	2,349,809
Carbon di oxide	lb/hr	614,626	614,626	638,358	641,655	642,957	642,957	599,076	615,928
Oxygen	lb/hr	205,551	205,551	213,561	214,062	217,019	216,494	201,718	207,463
Moisture	lb/hr	309,692	309,692	321,775	324,547	325,965	326,852	304,545	312,875
Sulfur di oxide	lb/hr	11,381	11,381	11,814	11,814	11,814	11,700	10,901	11,267
Sulfur tri oxide	lb/hr	0	0	7	7	7	149	139	142
Nitrogen oxide	lb/hr	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/hr	1,670	1,670	1,660	1,670	1,670	159	148	167
Argon	lb/hr	0	0	10	10	218	218	203	208
Ammonia	lb/hr	0	0	0	0	562	5	5	5
Particulate	lb/hr	70	70	73	73	73	73	0	70

Burns & McDonnell for Minnkota Power
Milton Young Station

Low Dust & Tail End Selective Catalytic Reduction (SCR) Systems
Additional Mass Balance Data

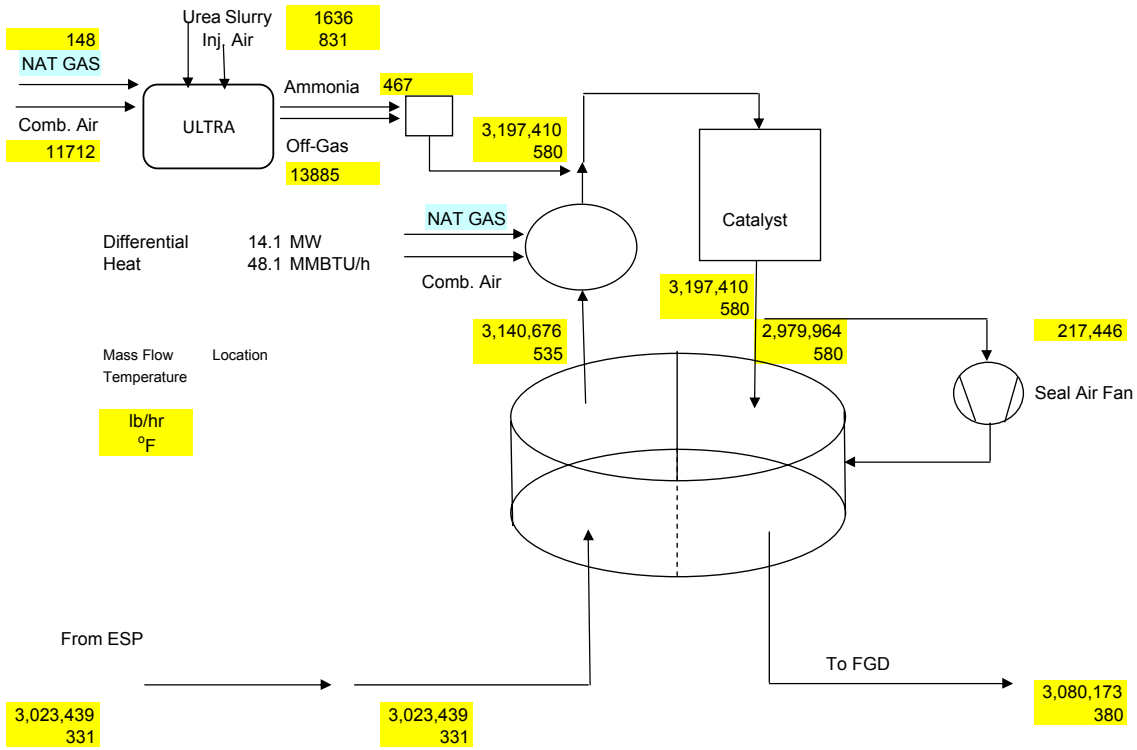
		Unit 1 Low Dust	Unit 1 Tail End	Unit 2 Low Dust	Unit 2 Tail End
Reheat Natural Gas	MMBtu/hr	30	33	43.1	49.2
Reheat Natural Gas	scfm	491	965	704	803
Burner System	% Air				
Burner System	Air Lb/hr	28,221	55,490	40,514	46,216
ULTRA System Natural Gas	MMBtu/hr	4.27	4.04	3.33	3.33
ULTRA System Natural Gas	scfm	70	66	54	54
NOx Reheat Natural Gas	Lb/hr	5	9	6	7
NOx ULTRA Natural Gas	Lb/hr	1.5	1.5	1.1	1.1
Reactor Total Efficiency	%	90.49	90.54	90.53	90

MRY 2 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



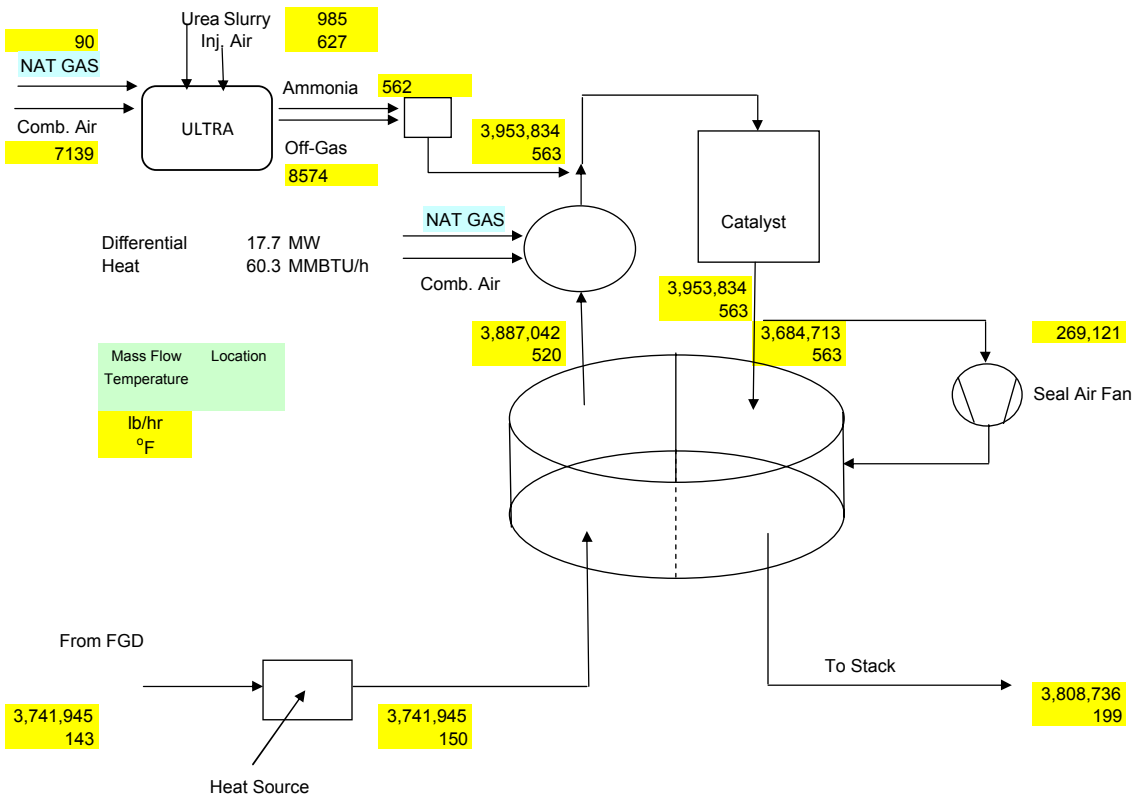
		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Stack
Nitrogen	lb/h	2,063,089	2,063,089	2,143,153	2,180,798	2,190,180	2,191,336	2,042,555	2,073,613
Carbon di oxide	lb/h	542,901	542,901	563,883	569,281	570,295	570,295	531,575	543,915
Oxygen	lb/h	184,328	184,328	191,503	192,324	194,569	194,130	180,949	185,704
Moisture	lb/h	437,137	437,137	454,118	458,657	459,759	460,502	429,236	439,707
Sulfur di oxide	lb/h	496	496	514	514	514	510	475	491
Sulfur tri oxide	lb/h	0	0	0	0	0	6	6	6
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,389	1,389	1,381	1,397	1,397	132	123	139
Argon	lb/h	0	0	8	8	167	167	156	159
Ammonia	lb/h	0	0	0	0	468	5	5	5
Particulate	lb/h	77	77	80	80	80	80	0	77

MRY 2 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



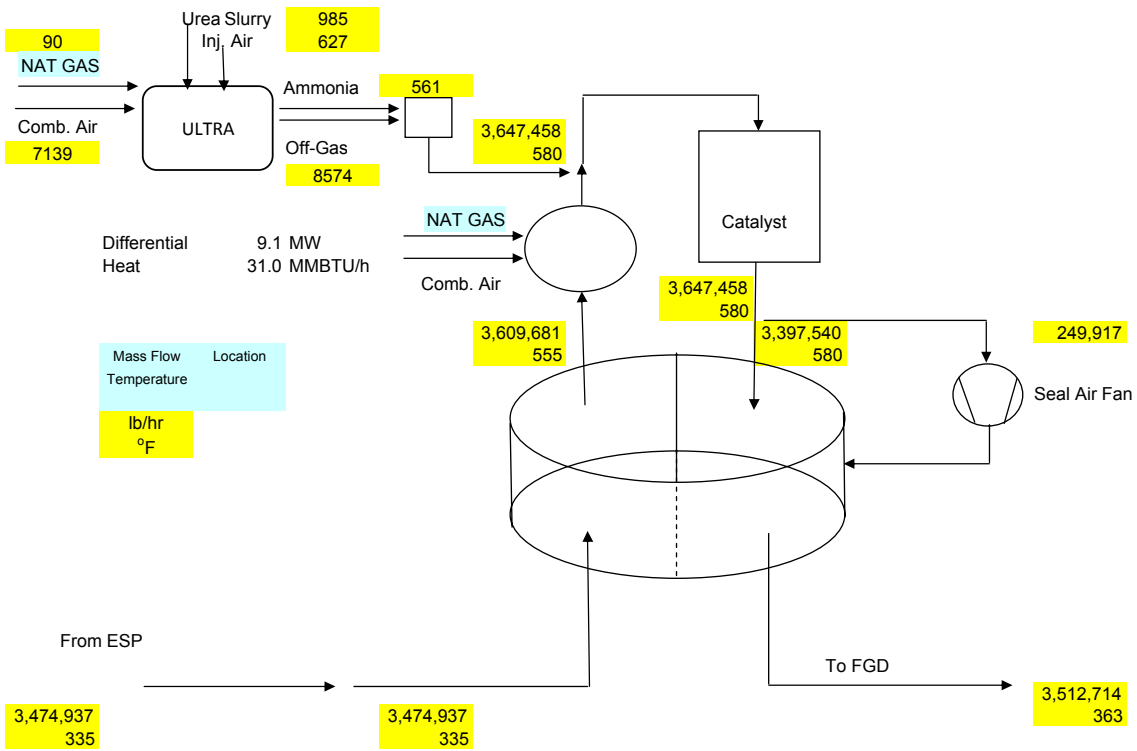
		ESP Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	FGD Inlet
Nitrogen	lb/h	2,031,828	2,031,828	2,110,656	2,143,657	2,153,039	2,154,192	2,007,837	2,042,352
Carbon di oxide	lb/h	536,419	536,419	557,143	561,875	562,889	562,889	524,646	537,433
Oxygen	lb/h	177,258	177,258	184,157	184,877	187,122	186,683	174,000	178,633
Moisture	lb/h	270,167	270,167	280,707	284,686	285,788	286,530	267,063	272,738
Sulfur di oxide	lb/h	9,934	9,934	10,312	10,312	10,312	10,213	9,519	9,835
Sulfur tri oxide	lb/h	0	0	6	6	6	130	121	124
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,389	1,389	1,381	1,395	1,395	132	123	139
Argon	lb/h	0	0	8	8	167	167	156	159
Ammonia	lb/h	0	0	0	0	468	5	4	5
Particulate	lb/h	77	77	80	80	80	80	0	77

MRY 1 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated	Stack
Nitrogen	lb/h	2,371,943	2,371,943	2,463,985	2,508,879	2,514,687	2,516,076	2,344,997	2,379,123
Carbon di oxide	lb/h	622,053	622,053	646,129	652,566	653,180	653,180	608,768	622,667
Oxygen	lb/h	213,652	213,652	221,928	222,907	224,302	223,774	208,558	214,002
Moisture	lb/h	536,485	536,485	557,343	562,756	563,425	564,318	525,948	538,919
Sulfur di oxide	lb/h	568	568	590	590	590	584	545	563
Sulfur tri oxide	lb/h	0	0	0	0	0	7	7	7
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,670	1,670	1,660	1,679	1,679	159	148	167
Argon	lb/h	0	0	5	5	103	103	96	98
Ammonia	lb/h	0	0	0	0	563	6	6	6
Particulate	lb/h	70	70	73	73	73	73	0	70

MRY 1 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



		ESP Outlet	GGH inlet	GGH outlet	Burner out	Catalyst Inlet	Catalyst Outlet	GGH treated inlet	FGD Inlet
Nitrogen	lb/hr	2,336,123	2,336,123	2,426,758	2,449,060	2,454,868	2,456,248	2,288,130	2,343,304
Carbon di oxide	lb/hr	614,626	614,626	638,408	641,606	642,220	642,220	598,263	615,240
Oxygen	lb/hr	205,551	205,551	213,511	213,998	215,393	214,868	200,161	205,901
Moisture	lb/hr	309,692	309,692	321,780	324,469	325,138	326,026	303,711	312,126
Sulfur di oxide	lb/hr	11,381	11,381	11,815	11,815	11,815	11,701	10,901	11,267
Sulfur tri oxide	lb/hr	0	0	7	7	7	149	139	142
Nitrogen oxide	lb/hr	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/hr	1,670	1,670	1,660	1,669	1,669	159	148	167
Argon	lb/hr	0	0	5	5	103	103	96	98
Ammonia	lb/hr	0	0	0	0	562	5	5	5
Particulate	lb/hr	70	70	73	73	73	73	0	70

Blakley, Robert

From: Robert Johnson [RJohnson@ftek.com]
Sent: Friday, September 25, 2009 6:59 AM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: MRYS Mass Balance Revision
Attachments: 24Sep09_BMcD for MRYS_Additional Process Data_R1.pdf; 22Sep09_MRY1TailEnd_Rev3_natgas.pdf

Bob,
Attached are the corrected data for the reheat requirements and the updated PFD for U1TE that reflects the corrected urea slurry rate.

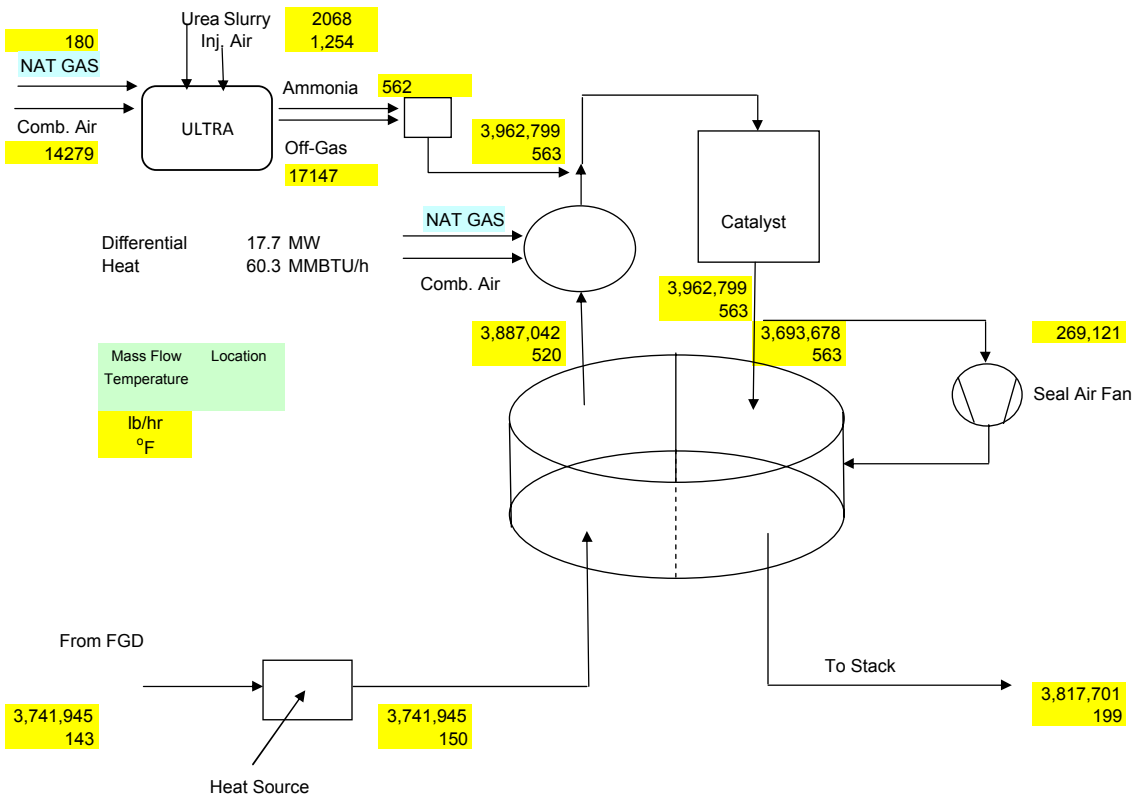
Please let us know if we can clarify anything.
Best Regards, Bob

Robert E. Johnson
Fuel Tech, Inc
(913) 897 0727

This message contains information that may be privileged, confidential or otherwise protected from disclosure. Unless you are the intended addressee (or authorized recipient for the addressee) you may not use, copy or disclose this message or information contained in this message to anyone. If you received this message in error, please notify the sender by replying to this message and then delete it from your system without copying or disclosing it. Thank you.

<<24Sep09_BMcD for MRYS_Additional Process Data_R1.pdf>> <<22Sep09_MRY1TailEnd_Rev3_natgas.pdf>>

MRY 1 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated	Stack
Nitrogen	lb/h	2,371,943	2,371,943	2,464,003	2,509,202	2,520,818	2,522,207	2,351,099	2,384,931
Carbon di oxide	lb/h	622,053	622,053	646,089	652,570	653,798	653,798	609,444	623,281
Oxygen	lb/h	213,652	213,652	221,973	222,959	225,749	225,220	209,941	215,397
Moisture	lb/h	536,485	536,485	557,315	562,765	564,103	564,996	526,667	539,588
Sulfur di oxide	lb/h	568	568	590	590	590	584	545	563
Sulfur tri oxide	lb/h	0	0	0	0	0	7	7	7
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,670	1,670	1,660	1,679	1,679	159	148	167
Argon	lb/h	0	0	10	10	206	206	192	196
Ammonia	lb/h	0	0	0	0	563	6	6	6
Particulate	lb/h	70	70	73	73	73	73	0	70

Burns & McDonnell for Minnkota Power
Milton Young Station

Low Dust & Tail End Selective Catalytic Reduction (SCR) Systems
Additional Mass Balance Data (Rev 1)

		Unit 1 Low Dust	Unit 1 Tail End	Unit 2 Low Dust (per reactor)	Unit 2 Tail End (per reactor)
Reheat Natural Gas	MMBtu/hr	31.1	60.3	48.1	50.8
Reheat Natural Gas	scfm	491	965	704	803
Burner System	% Air				
Burner System	Air Lb/hr	28,221	55,490	40,514	46,216
ULTRA System Natural Gas	MMBtu/hr	4.27	4.04	3.33	3.33
ULTRA System Natural Gas	scfm	70	66	54	54
NOx Reheat Natural Gas	Lb/hr	5	9	6	7
NOx ULTRA Natural Gas	Lb/hr	1.5	1.5	1.1	1.1
Reactor Total Efficiency	%	90.49	90.54	90.53	90

From: Stu Libby [mailto:slibby@minnkota.com]
Sent: Fri 9/25/2009 1:31 PM
To: Dyer, Paul
Subject: Fw: [aregc] SCR Maintenance

Here is a B&W response.

Stuart M. Libby
Plant Manager-Operations
Minnkota Power Cooperative
Milton R. Young Station
Tel (701) 794-7215
Cell (701) 391-3653
Fax (701) 794-7258
slibby@minnkota.com
----- Forwarded by Stu Libby/PowerProduction/Minnkota on 09/25/2009 01:29 PM -----

From: "Andrisevic, Dean M" <dmandrisevic@babcock.com>

To: "Piechocki, Matthew A" <MAPiechocki@diamondpower.com>, <slibby@minnkota.com>

Cc: "Pavlik, David L" <dlpavlik@babcock.com>, "Koslosky, John V" <jvkoslosky@babcock.com>

Date: 09/25/2009 01:20 PM

Subject: RE: [aregc] SCR Maintenance

Stu

I will try to give you some answers to your questions although as you are aware, in this business there are so many variables that affect the outcome, it is difficult come up with some absolutes.

1) cool-down of the SCR; Depending upon the outside air temperature and specific operating procedures which should open all dampers, doors and continuous operation of the fans, we typically see 36 to 48 hrs before entering the SCR.

(2) removal of the catalyst including time to scaffold, and vacuum ash prior to catalyst removal; This is dependent upon the your design, humidity, your operation of the sonic horns and pitch of your chosen catalyst. We have seen anything from a shift to several days to perform the vacuuming. Scaffolding is minimal and is installed in less than a shift.

(3) replacement of the catalyst including time to remove scaffolding, planking and re-seal the reactor; Typical removal on and replacement on units in the 500-650MW size has been accomplished in approximately 1 week per layer of catalyst, separate SCR boxes can accommodate simultaneous work but we typically don't have people working on top of each other. This is dependent upon the type of catalyst, number of blocks, design which should include permanent monorails for every layer and sufficient hoisting equipment.

(4) total time elapsed from shutdown of ammonia feed to restart of Ammonia - I'm sorry but at this time, I do not have any information to share on this item.

Hopefully this helps.

Sincerely

Dean M. Andrisevic
General Manager Central Operations
Babcock & Wilcox Construction Co. Inc.

-----Original Message-----
From: Piechocki, Matthew A
Sent: Tuesday, September 22, 2009 12:51 PM
To: slibby@minnkota.com
Cc: Andrisevic, Dean M; Pavlik, David L; Koslosky, John V
Subject: FW: [aregc] SCR Maintenance

Stu,

I don't know if you have requested support from anyone within the Babcock & Wilcox Construction organization, but they should be very qualified to answer your questions regarding SCR demo and installation.

I have copied several individuals within the B&W Co. that should be able to provide you the information you need.

Good luck.

Matt Piechocki
New Project Business Development
Diamond Power International, Inc.
Phone (740) 687-4065
Cell (614) 648-0191
Fax (740) 687-4304
e-mail mapiechocki@diamondpower.com

-----Original Message-----
From: Stu Libby [mailto:slibby@minnkota.com]
Sent: Tuesday, September 22, 2009 11:32 AM
To: The Association of Rural Electric Generating Cooperatives
Cc: pdyer@burnsmcd.com

Subject: [aregc] SCR Maintenance

Hi, Everyone,

On September 2, 2009, I sent out a request for information regarding SCR maintenance. I did receive some responses and I greatly appreciate it. However, it appears that I lacked specificity in my question. Therefore, I am once again appealing to you for additional information. I will be grateful for any help you can give me by responding to the questions below. Thanks all.

We are investigating the requirements for a possible SCR retrofit at Milton R. Young Station. We need to assess the time required to change out a layer of catalyst in an SCR for cases in which there is not a planned maintenance outage available. We need to know how long we can expect the unit to be down. We are looking for actual experience as to the time required for the following steps in this process:
(1) cool-down of the SCR;
(2) removal of the catalyst including time to scaffold, and vacuum ash prior to catalyst removal;
(3) replacement of the catalyst including time to remove scaffolding, planking and re-seal the reactor;
(4) total time elapsed from shutdown of ammonia feed to restart of ammonia feed. For comparison purposes, please indicate the number of catalyst modules involved in your case.

Please indicate the number of shifts and shift length or total elapsed time hours for each step (1-4) above. Please also indicate the time required to stage for the change-out assuming the change-out occurs as a non-planned activity.

Stuart M. Libby
Plant Manager-Operations
Minnkota Power Cooperative
Milton R. Young Station
Tel (701) 794-7215
Cell (701) 391-3653
Fax (701) 794-7258
slibby@minnkota.com

--- You are currently subscribed to aregc
with the email address: mlgossel@diamondpower.com
To unsubscribe send a blank email to:
leave-aregc@lists.cooperative.com
or click here:
http://lists.cooperative.com/u?id=1481803.255c57fcbe941be47140d3f0d70a6364&n=T&l=aregc&o=2206171

This message is intended only for the individual or entity to which it is addressed and contains information that is proprietary to Babcock & Wilcox Construction Co., Inc. and/or its affiliates, or may be otherwise confidential. If the reader of this message is not the intended recipient, or the employee agent responsible for delivering the message to the intended recipient, you are hereby notified that any dissemination, distribution or copying of this

communication is strictly prohibited. If you have received this communication in error, please notify the sender immediately by return e-mail and delete this message from your computer. Thank you.

Blakley, Robert

From: Blakley, Robert
Sent: Friday, September 25, 2009 3:31 PM
To: Robert Johnson
Cc: Volker Rummenhohl; 51684
Subject: RE: MRYS Mass Balance Revision
Attachments: 11Sep09_MRY2LowDust_Rev1_natgas_580F.pdf; 11Sep09_MRY2TailEnd_Rev1_natgas.pdf; 22Sep09_MRY1LowDust_Rev2_natgas_580F.pdf; 22Sep09_MRY1TailEnd_Rev3_natgas.pdf; 24Sep09_BMcD for MRYS_Additional Process Data_R1.pdf

Bob -

As we discussed, please check the total gas mass flow numbers in the PFDs versus the sum of the values copied from the spreadsheet as they do not match for any of the four cases:
> 9/11 U2 TE & LD SCRs
> 9/22 U1 LD SCR and 9/24 U1 TE SCR.

Also, in these PFDs, the urea mass flow and ULTRA system natural gas heat input for the Unit 1 low dust SCR are not the same as the Unit 1 tail end SCR, which we believe should match.
The revised summary table also shows two different values for the ULTRA system natural gas flows for Unit 1. Unit 2's ULTRA numbers are matching.

We appreciate your help in getting this corrected and back to us on Monday, 9/28.

Bob Blakley

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Friday, September 25, 2009 6:59 AM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: MRYS Mass Balance Revision

Bob,
Attached are the corrected data for the reheat requirements and the updated PFD for U1TE that reflects the corrected urea slurry rate.

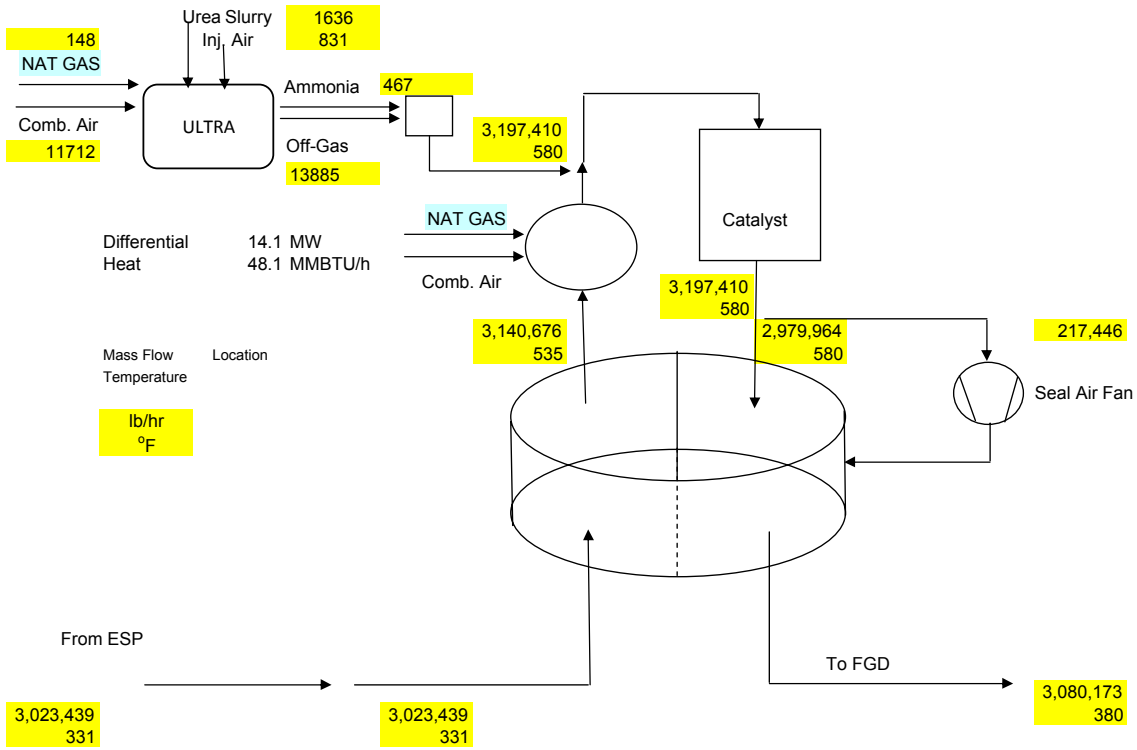
Please let us know if we can clarify anything.
Best Regards, Bob

Robert E. Johnson
Fuel Tech, Inc
(913) 897 0727

This message contains information that may be privileged, confidential or otherwise protected from disclosure. Unless you are the intended addressee (or authorized recipient for the addressee) you may not use, copy or disclose this message or information contained in this message to anyone. If you received this message in error, please notify the sender by replying to this message and then delete it from your system without copying or disclosing it. Thank you.

<<24Sep09_BMcD for MRYS_Additional Process Data_R1.pdf>> <<22Sep09_MRY1TailEnd_Rev3_natgas.pdf>>

MRY 2 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



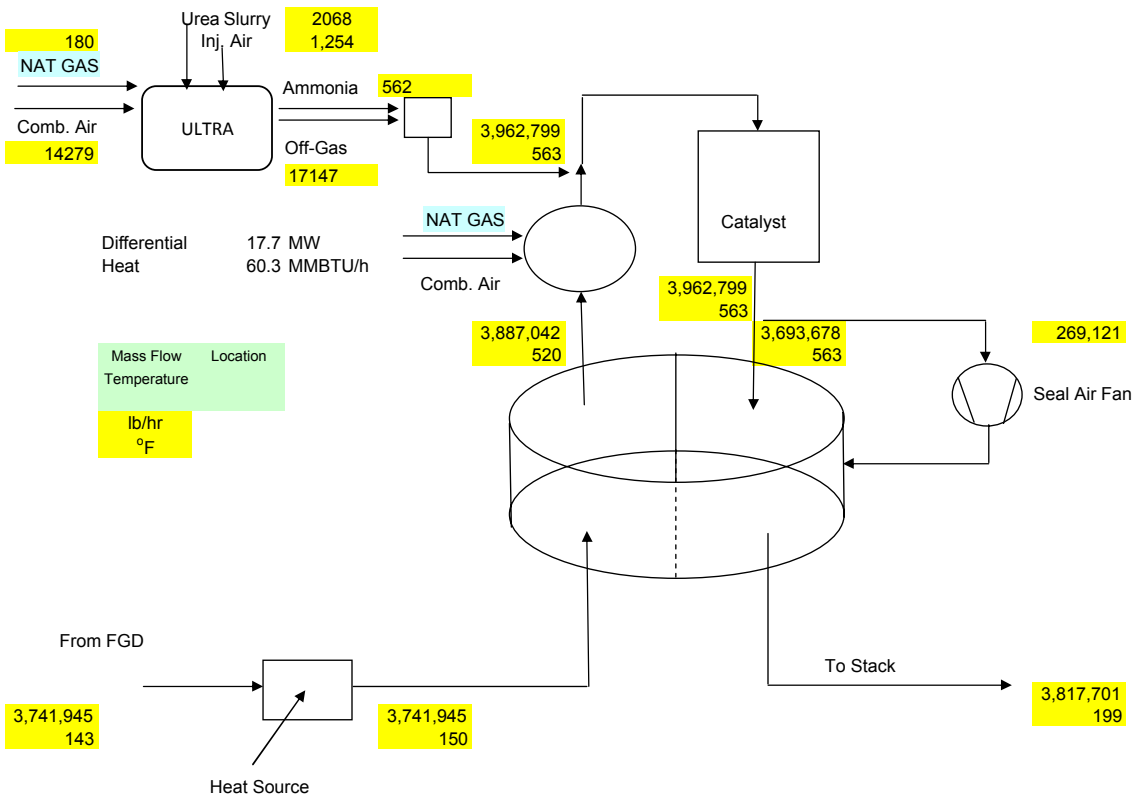
		ESP Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	FGD Inlet
Nitrogen	lb/h	2,031,828	2,031,828	2,110,656	2,143,657	2,153,039	2,154,192	2,007,837	2,042,352
Carbon di oxide	lb/h	536,419	536,419	557,143	561,875	562,889	562,889	524,646	537,433
Oxygen	lb/h	177,258	177,258	184,157	184,877	187,122	186,683	174,000	178,633
Moisture	lb/h	270,167	270,167	280,707	284,686	285,788	286,530	267,063	272,738
Sulfur di oxide	lb/h	9,934	9,934	10,312	10,312	10,312	10,213	9,519	9,835
Sulfur tri oxide	lb/h	0	0	6	6	6	130	121	124
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,389	1,389	1,381	1,395	1,395	132	123	139
Argon	lb/h	0	0	8	8	167	167	156	159
Ammonia	lb/h	0	0	0	0	468	5	4	5
Particulate	lb/h	77	77	80	80	80	80	0	77

Burns & McDonnell for Minnkota Power
Milton Young Station

Low Dust & Tail End Selective Catalytic Reduction (SCR) Systems
Additional Mass Balance Data (Rev 1)

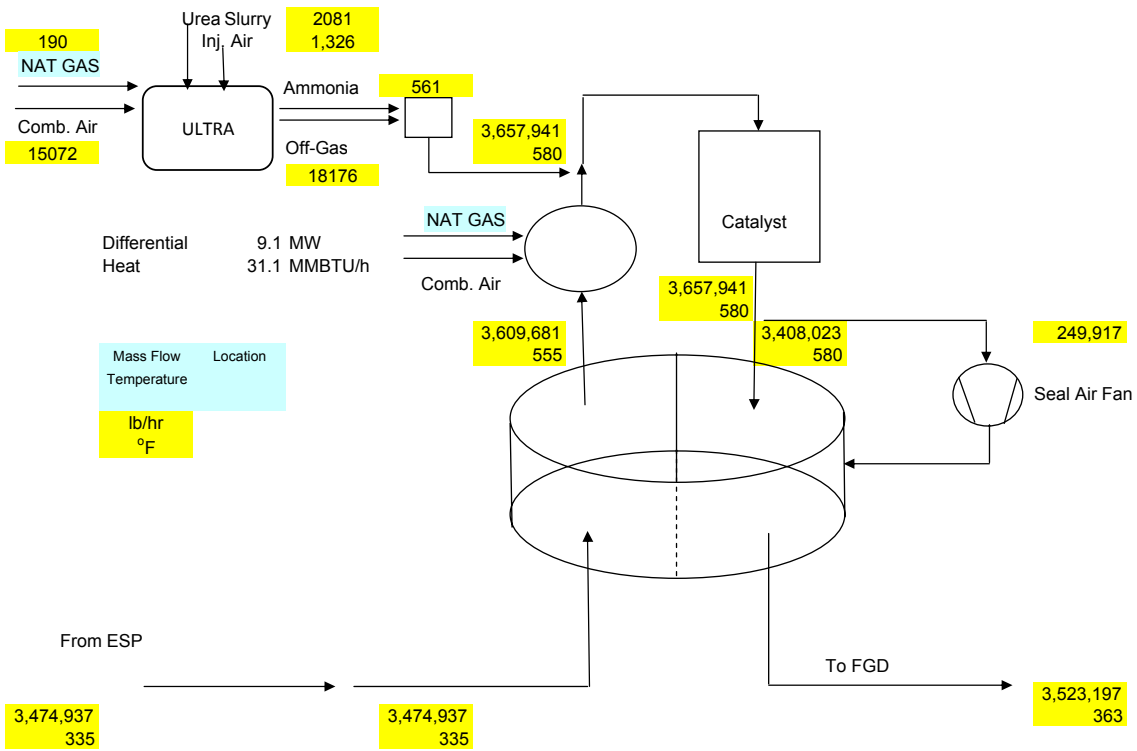
		Unit 1 Low Dust	Unit 1 Tail End	Unit 2 Low Dust (per reactor)	Unit 2 Tail End (per reactor)
Reheat Natural Gas	MMBtu/hr	31.1	60.3	48.1	50.8
Reheat Natural Gas	scfm	491	965	704	803
Burner System	% Air				
Burner System	Air Lb/hr	28,221	55,490	40,514	46,216
ULTRA System Natural Gas	MMBtu/hr	4.27	4.04	3.33	3.33
ULTRA System Natural Gas	scfm	70	66	54	54
NOx Reheat Natural Gas	Lb/hr	5	9	6	7
NOx ULTRA Natural Gas	Lb/hr	1.5	1.5	1.1	1.1
Reactor Total Efficiency	%	90.49	90.54	90.53	90

MRY 1 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



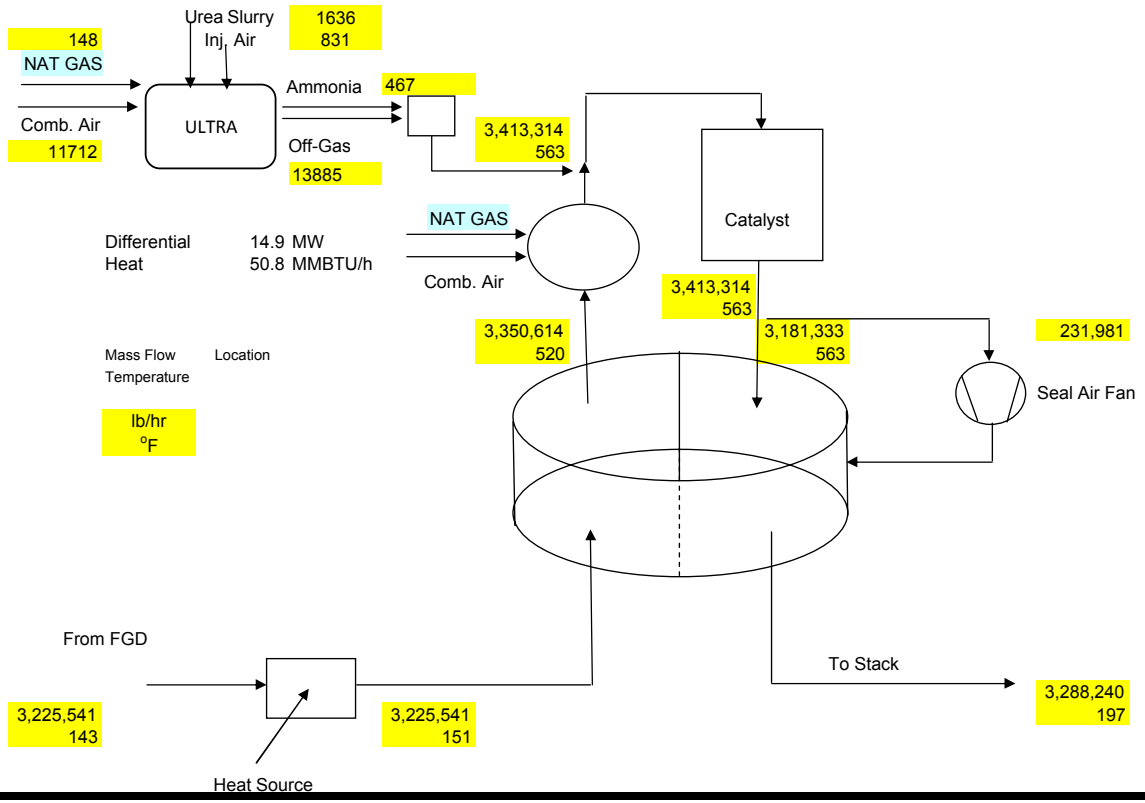
		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated	Stack
Nitrogen	lb/h	2,371,943	2,371,943	2,464,003	2,509,202	2,520,818	2,522,207	2,351,099	2,384,931
Carbon di oxide	lb/h	622,053	622,053	646,089	652,570	653,798	653,798	609,444	623,281
Oxygen	lb/h	213,652	213,652	221,973	222,959	225,749	225,220	209,941	215,397
Moisture	lb/h	536,485	536,485	557,315	562,765	564,103	564,996	526,667	539,588
Sulfur di oxide	lb/h	568	568	590	590	590	584	545	563
Sulfur tri oxide	lb/h	0	0	0	0	0	7	7	7
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,670	1,670	1,660	1,679	1,679	159	148	167
Argon	lb/h	0	0	10	10	206	206	192	196
Ammonia	lb/h	0	0	0	0	563	6	6	6
Particulate	lb/h	70	70	73	73	73	73	0	70

MRY 1 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



		ESP Outlet	GGH inlet	GGH outlet	Burner out	Catalyst Inlet	Catalyst Outlet	GGH treated	FGD Inlet
Nitrogen	lb/hr	2,336,123	2,336,123	2,426,760	2,449,748	2,462,061	2,463,441	2,295,314	2,349,809
Carbon di oxide	lb/hr	614,626	614,626	638,358	641,655	642,957	642,957	599,076	615,928
Oxygen	lb/hr	205,551	205,551	213,561	214,062	217,019	216,494	201,718	207,463
Moisture	lb/hr	309,692	309,692	321,775	324,547	325,965	326,852	304,545	312,875
Sulfur di oxide	lb/hr	11,381	11,381	11,814	11,814	11,814	11,700	10,901	11,267
Sulfur tri oxide	lb/hr	0	0	7	7	7	149	139	142
Nitrogen oxide	lb/hr	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/hr	1,670	1,670	1,660	1,670	1,670	159	148	167
Argon	lb/hr	0	0	10	10	218	218	203	208
Ammonia	lb/hr	0	0	0	0	562	5	5	5
Particulate	lb/hr	70	70	73	73	73	73	0	70

MRY 2 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Stack
Nitrogen	lb/h	2,063,089	2,063,089	2,143,153	2,180,798	2,190,180	2,191,336	2,042,555	2,073,613
Carbon di oxide	lb/h	542,901	542,901	563,883	569,281	570,295	570,295	531,575	543,915
Oxygen	lb/h	184,328	184,328	191,503	192,324	194,569	194,130	180,949	185,704
Moisture	lb/h	437,137	437,137	454,118	458,657	459,759	460,502	429,236	439,707
Sulfur di oxide	lb/h	496	496	514	514	514	510	475	491
Sulfur tri oxide	lb/h	0	0	0	0	0	6	6	6
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,389	1,389	1,381	1,397	1,397	132	123	139
Argon	lb/h	0	0	8	8	167	167	156	159
Ammonia	lb/h	0	0	0	0	468	5	5	5
Particulate	lb/h	77	77	80	80	80	80	0	77

Blakley, Robert

From: Robert Johnson [RJohnson@ftek.com]
Sent: Monday, September 28, 2009 10:05 AM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: 28Sep_PFD Revisions
Attachments: 28Sep09_MRY2TailEnd_Rev2_natgas.pdf; 27Sep09_BMcD for MRYS_Additional Process Data_R2.doc; 28Sep09_MRY1LowDust_Rev3_natgas_580F.pdf; 28Sep09_MRY1TailEnd_Rev4_natgas.pdf; 28Sep09_MRY2LowDust_Rev2_natgas_580F.pdf

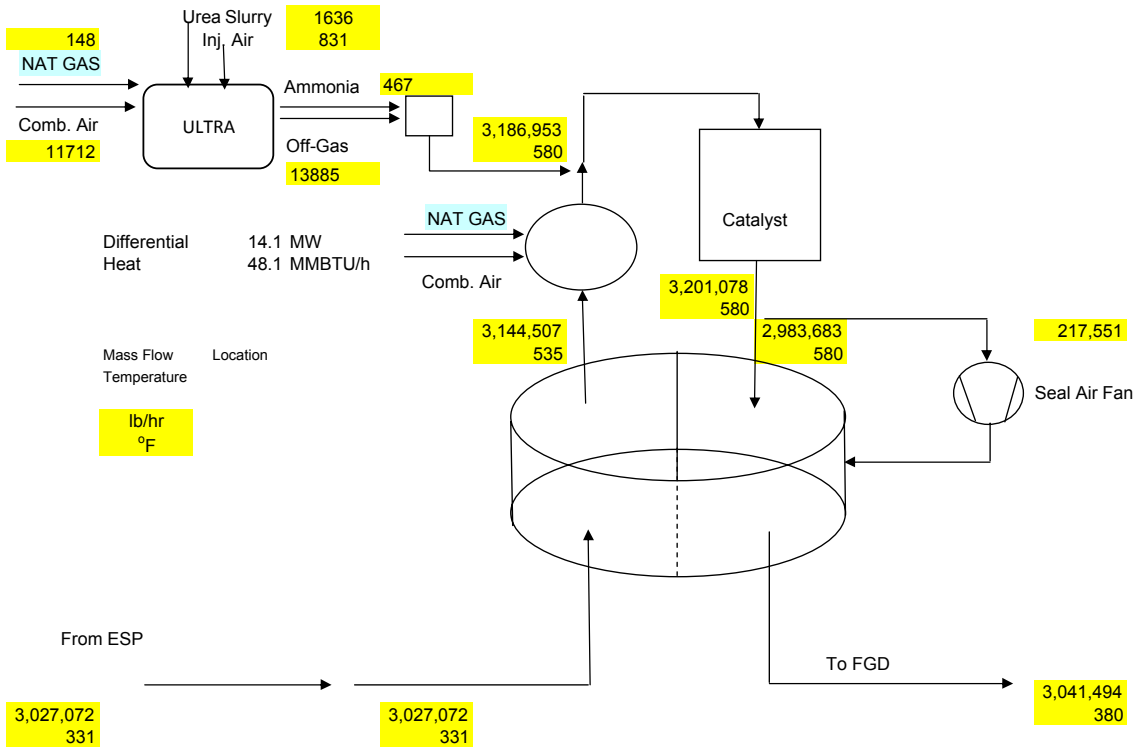
Bob,
Attached are the revised PFDs.
I added a summary line to the mass balance table, and all of the flows match those on the flow diagram.
The balance around the ULTRA system for the U1 systems has been corrected.
Please let us know if we can clarify anything.
Best Regards, Bob

Robert E. Johnson
Fuel Tech, Inc
(913) 897 0727

This message contains information that may be privileged, confidential or otherwise protected from disclosure. Unless you are the intended addressee (or authorized recipient for the addressee) you may not use, copy or disclose this message or information contained in this message to anyone. If you received this message in error, please notify the sender by replying to this message and then delete it from your system without copying or disclosing it. Thank you.

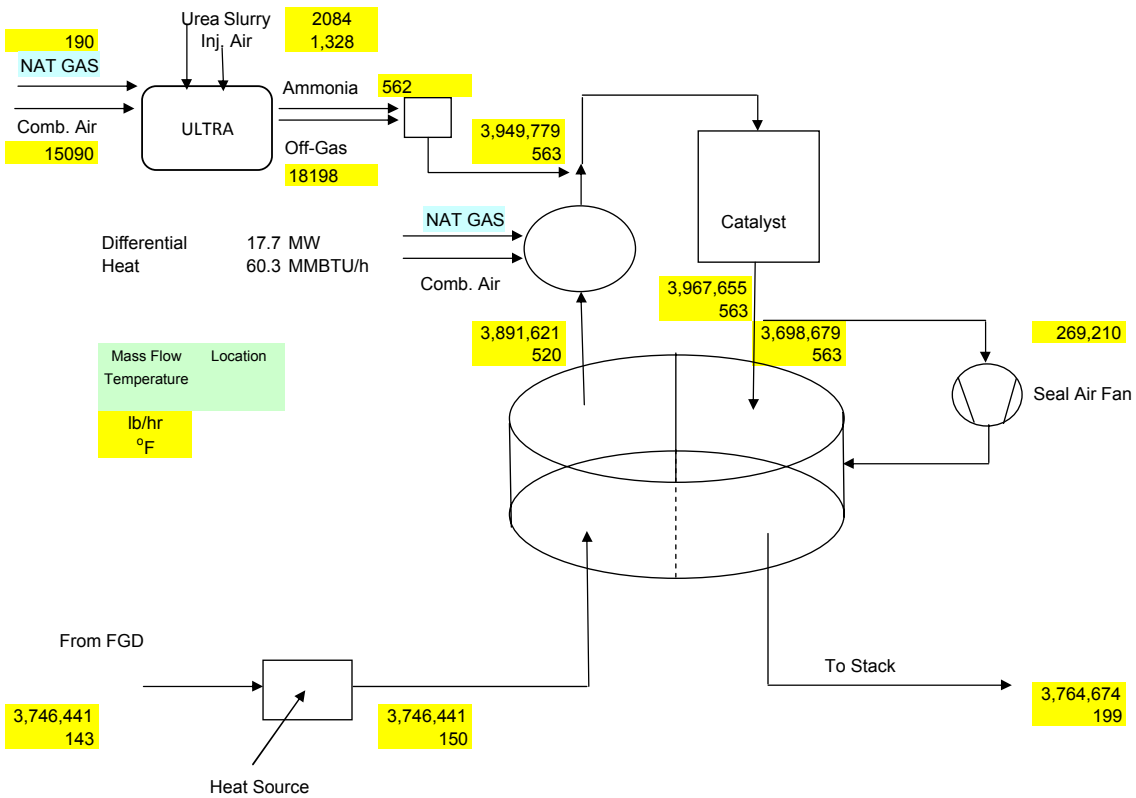
<<28Sep09_MRY2TailEnd_Rev2_natgas.pdf>> <<27Sep09_BMcD for MRYS_Additional Process Data_R2.doc>> <<28Sep09_MRY1LowDust_Rev3_natgas_580F.pdf>> <<28Sep09_MRY1TailEnd_Rev4_natgas.pdf>> <<28Sep09_MRY2LowDust_Rev2_natgas_580F.pdf>>

MRY 2 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



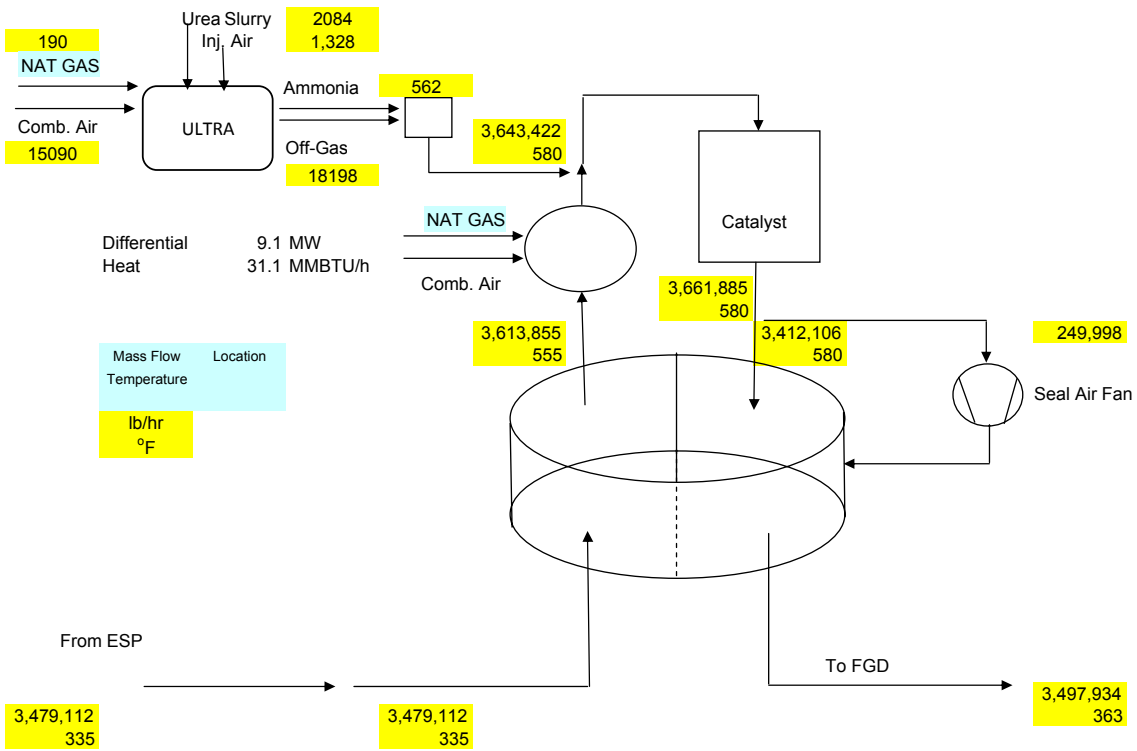
		ESP Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	FGD Inlet
Nitrogen	lb/h	2,031,828	2,031,828	2,110,694	2,143,695	2,153,077	2,154,231	2,007,981	2,042,352
Carbon di oxide	lb/h	536,419	536,419	557,153	561,885	562,899	562,899	524,684	537,433
Oxygen	lb/h	177,258	177,258	184,161	184,881	187,126	186,686	174,012	178,633
Moisture	lb/h	270,167	270,167	280,712	284,691	285,793	286,535	267,082	272,738
Sulfur di oxide	lb/h	9,934	9,934	10,312	10,312	10,312	10,213	9,519	9,835
Sulfur tri oxide	lb/h	0	0	6	6	6	130	121	124
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,389	1,389	1,381	1,395	1,395	132	123	139
Argon	lb/h	0	0	8	8	167	167	156	159
Ammonia	lb/h	0	0	0	0	468	5	4	5
Particulate	lb/h	77	77	80	80	80	80	0	77
Total	lb/h	3,027,072	3,027,072	3,144,507	3,186,953	3,201,323	3,201,078	2,983,683	3,041,494

MRY 1 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated	Stack
Nitrogen	lb/h	2,371,943	2,371,943	2,463,945	2,509,161	2,521,083	2,522,472	2,351,512	2,385,237
Carbon di oxide	lb/h	622,053	622,053	646,071	652,555	653,815	653,815	609,503	623,313
Oxygen	lb/h	213,652	213,652	221,970	222,956	225,821	225,293	210,023	215,472
Moisture	lb/h	536,485	536,485	557,301	562,753	564,141	565,034	526,739	539,638
Sulfur di oxide	lb/h	568	568	590	590	590	584	545	563
Sulfur tri oxide	lb/h	0	0	0	0	0	7	7	7
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,670	1,670	1,660	1,679	1,679	159	148	167
Argon	lb/h	0	0	10	10	211	211	197	201
Ammonia	lb/h	0	0	0	0	563	6	6	6
Particulate	lb/h	70	70	73	73	73	73	0	70
Total	lb/hr	3,746,441	3,746,441	3,891,621	3,949,779	3,967,977	3,967,655	3,698,679	3,764,674

MRY 1 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



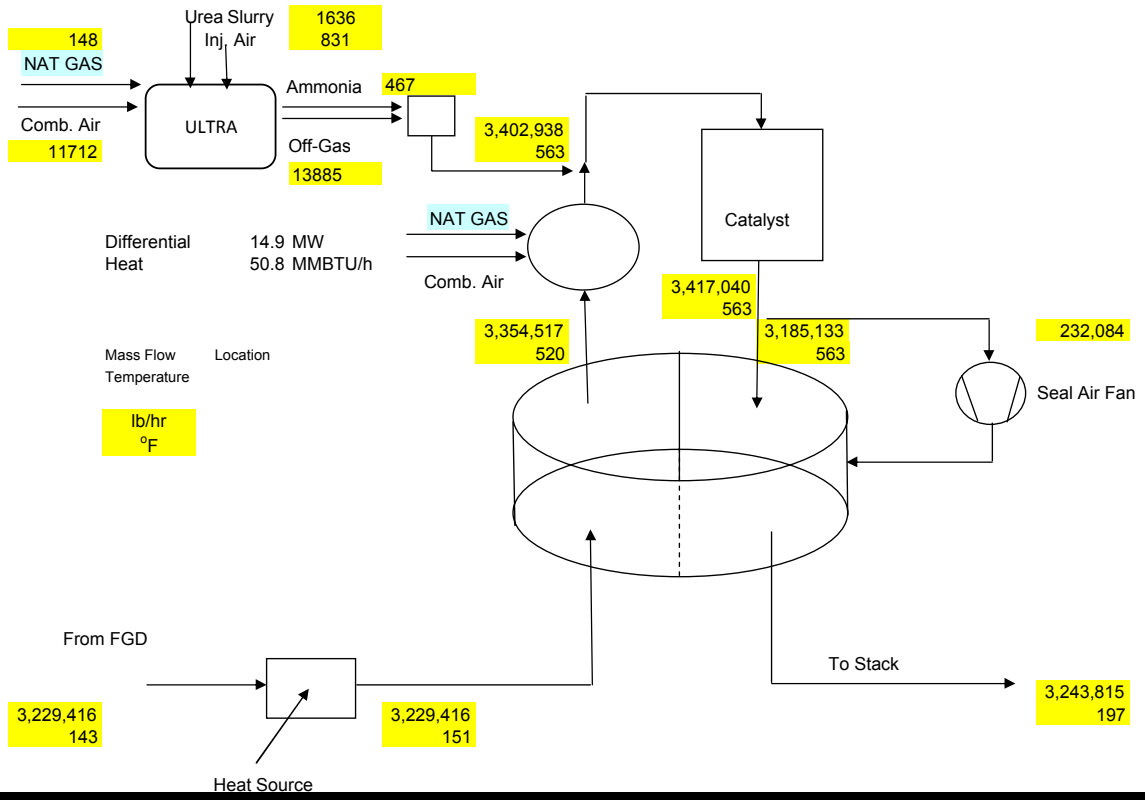
		ESP Outlet	GGH inlet	GGH outlet	Burner out	Catalyst Inlet	Catalyst Outlet	GGH treated	FGD Inlet
Nitrogen	lb/hr	2,336,123	2,336,123	2,426,651	2,449,638	2,461,951	2,463,331	2,295,352	2,349,809
Carbon di oxide	lb/hr	614,626	614,626	638,330	641,626	642,928	642,928	599,086	615,928
Oxygen	lb/hr	205,551	205,551	213,551	214,052	217,009	216,484	201,722	207,463
Moisture	lb/hr	309,692	309,692	321,760	324,532	325,950	326,837	304,550	312,875
Sulfur di oxide	lb/hr	11,381	11,381	11,813	11,813	11,813	11,699	10,902	11,267
Sulfur tri oxide	lb/hr	0	0	7	7	7	149	139	142
Nitrogen oxide	lb/hr	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/hr	1,670	1,670	1,660	1,670	1,670	159	148	167
Argon	lb/hr	0	0	10	10	218	218	203	208
Ammonia	lb/hr	0	0	0	0	562	5	5	5
Particulate	lb/hr	70	70	73	73	73	73	0	70
Total	lb/hr	3,479,112	3,479,112	3,613,855	3,643,422	3,662,182	3,661,885	3,412,106	3,497,934

Burns & McDonnell for Minnkota Power
Milton Young Station

Low Dust & Tail End Selective Catalytic Reduction (SCR) Systems
Additional Mass Balance Data (Rev 2)

		Unit 1 Low Dust	**Unit 1 Tail End**	**Unit 2 Low Dust (per reactor)**	**Unit 2 Tail End (per reactor)**
Reheat Natural Gas	MMBtu/hr	31.1	60.3	48.1	50.8
Reheat Natural Gas	scfm	491	965	704	803
Burner System	% Air				
Burner System	Air Lb/hr	28,221	55,490	40,514	46,216
ULTRA System Natural Gas	MMBtu/hr	4.27	4.27	3.33	3.33
ULTRA System Natural Gas	scfm	70	70	54	54
NOx Reheat Natural Gas	Lb/hr	10	20	14	16
NOx ULTRA Natural Gas	Lb/hr	1.5	1.5	1.1	1.1
Reactor Total Efficiency	%	90.49	90.54	90.53	90

MRY 2 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Stack
Nitrogen	lb/h	2,063,089	2,063,089	2,143,074	2,180,720	2,190,102	2,191,257	2,042,589	2,073,613
Carbon di oxide	lb/h	542,901	542,901	563,862	569,261	570,275	570,275	531,584	543,915
Oxygen	lb/h	184,328	184,328	191,496	192,317	194,562	194,123	180,952	185,704
Moisture	lb/h	437,137	437,137	454,101	458,641	459,743	460,485	429,243	439,707
Sulfur di oxide	lb/h	496	496	514	514	514	509	475	491
Sulfur tri oxide	lb/h	0	0	0	0	0	6	6	6
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,389	1,389	1,381	1,397	1,397	132	123	139
Argon	lb/h	0	0	8	8	167	167	156	159
Ammonia	lb/h	0	0	0	0	468	5	5	5
Particulate	lb/h	77	77	80	80	80	80	0	77
Total	lb/h	3,229,416	3,229,416	3,354,517	3,402,938	3,417,308	3,417,040	3,185,133	3,243,815

Blakley, Robert

From: Steve Benson [sbenson@microbeam.com]
Sent: Monday, October 05, 2009 1:27 PM
To: Wayne Jones
Cc: Bryant, Ronald; Luther Kvernen
Subject: Sulfation of fine particles

Attachments: Sulfation of fly ash.pdf

Sulfation of fly ash.pdf (49 K...

Wayne,

Attached is some information on the increase in sulfation rates of small fly ash particles (less than 5 microns) with and without catalyst.

Let me know if you have questions.

Steve

Steven A. Benson, Ph.D.
President
Microbeam Technologies Inc.
4200 James Ray Drive, Ste. 191
Grand Forks, ND 58203
Ph. 701-777-6530
Cell 701-213-7070
Fax 701-777-6532
www.microbeam.com

Information contained in this e-mail and any attachments is privileged and confidential and is intended only for the use of the intended recipient named above. If the reader of this message is not the intended recipient, you are hereby notified that any dissemination, distribution, or copying of this message is strictly prohibited. If you have received this message in error, please contact the sender by return e-mail and destroy all copies of the original message and attachments.

Extracted from past report “Ash Impacts on SCR Performance, S. Benson, 2005.”

Tests of fly ash sulfation were conducted using a thermogravimetric analyzer (TGA). TGA testing was conducted using a <5-µm-size fraction of ash produced from Powder River Basin (PRB) coals and lignites and exposing them to vapor-phase sulfur dioxide with and without catalyst at several temperatures. The aim of the testing was to determine the potential of the formation of sulfates to cause particle-to-particle bonding that leads to the formation of deposits in the temperature range where SCR catalysts are used. The TGA testing is focused on determining the reactivity of the <5-µm ash produced from selected PRB and blends to sulfur dioxide and gas-phase phosphorus species as a function of temperature. Testing was conducted to determine the weight gain with flue gas containing ammonia. The impact temperature on the weight gain due to the formation of sulfates for a PRB blend is shown in Figure 8. The rates of sulfation were found to increase with increased temperature. The results show an increase in the weight gains when ammonia and phosphorus were added. Ground catalyst was mixed with PRB and placed in the TGA. Increases in weight gain were observed when catalyst was added as compared to baseline cases for 100% PRB, as shown in Figures 8 and 9, respectively. The presence of catalyst enhances the formation of sulfates.

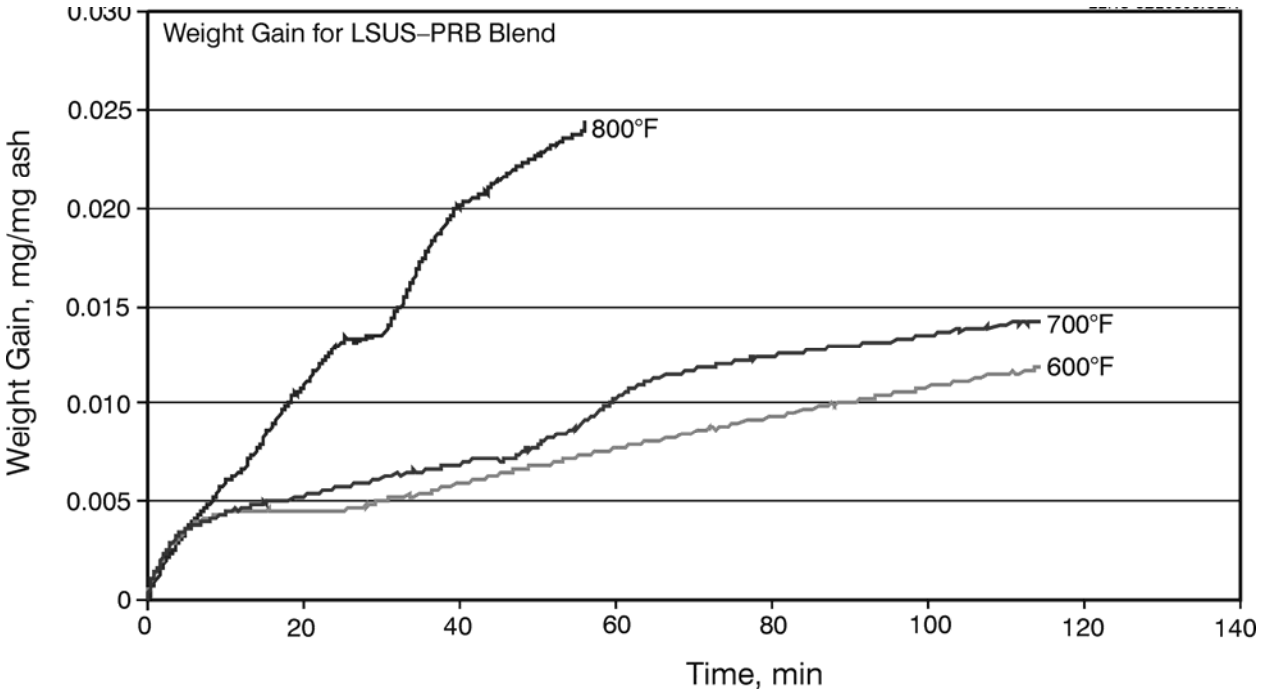


Figure 8. Weight changes for PRB-blend coal ash exposed to flue gases and ammonia at three temperatures.

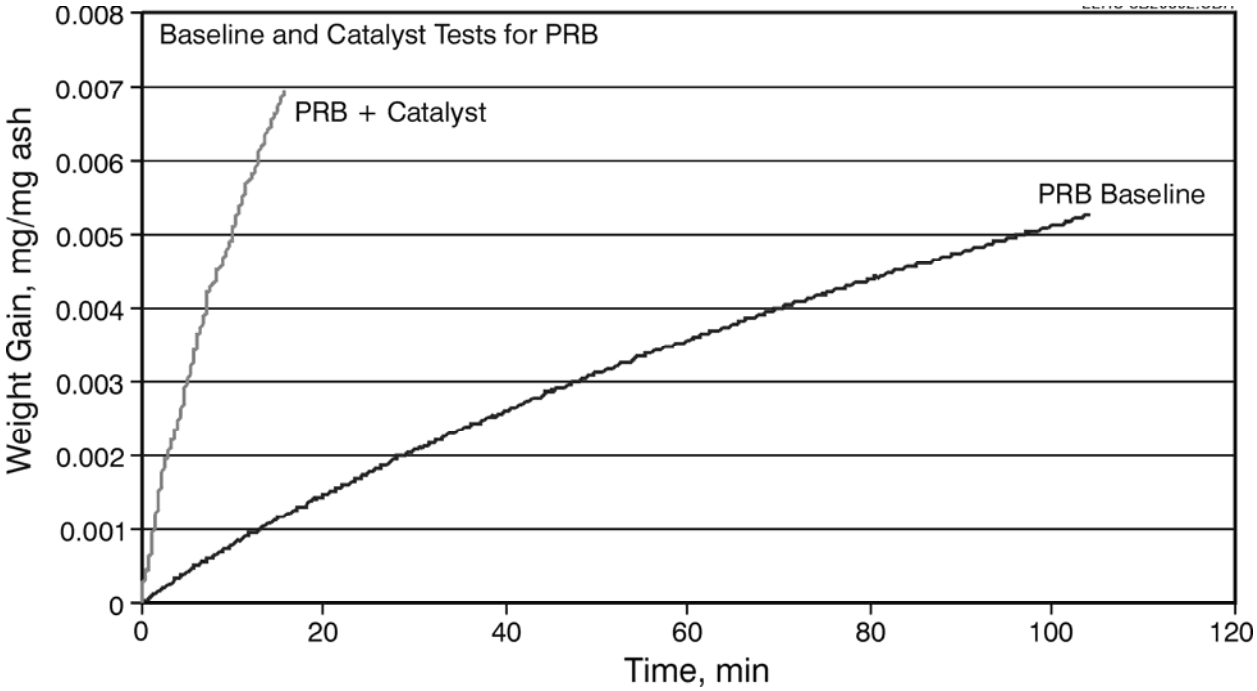


Figure 9. Weight changes for PRB-blend coal ash exposed to flue gases and ammonia with and without SCR catalyst present.

Blakley, Robert

From: Wayne Jones [WSJ@topsoe.com]
Sent: Friday, October 09, 2009 9:33 AM
To: Bryant, Ronald
Cc: TNW@topsoe.com
Subject: Minnkota

Ron,

I got a response back today from Denmark with answers to some of the questions posed during our conference call earlier this week.

Amager, has not started up so we have no data concerning SCR operation. They seem to be having problems with the boiler and FGD systems and that has prevented any significant run time.

Also, an issue came up yesterday requiring me to travel today. I had planned to finish the proposal today but I don't think that will be possible. I will work on it this weekend and have it you as early on Monday as possible.

Thanks,
Wayne

Wayne S. Jones
Sales Manager, Power Generation
Haldor Topsoe, Inc.
281-228-5136 (office)
281-228-5129 (fax)
281-684-8811 (cell)
wsj@topsoe.com
www.HaldorTopsoe.com

Blakley, Robert

From: Blakley, Robert
Sent: Tuesday, December 22, 2009 9:21 AM
To: Robert Johnson
Cc: 49861; Volker Rummenhohl; Blackwood, Dave; Bryant, Ronald; Weilert, Carl
Subject: FW: 28Sep_PFD Revisions
Attachments: 28Sep09_MRY2TailEnd_Rev2_natgas.pdf; 27Sep09_BMcD for MRYS_Additional Process Data_R2.doc; 28Sep09_MRY1LowDust_Rev3_natgas_580F.pdf; 28Sep09_MRY1TailEnd_Rev4_natgas.pdf; 28Sep09_MRY2LowDust_Rev2_natgas_580F.pdf

Bob -

Carl Weilert and I reviewed information involving hypothetical applications of tail end and low dust SCR technologies at Minnkota's Milton R. Young Station with the North Dakota Department of Health's Air Quality Division on Monday, December 21, 2009.

Estimated Natural Gas Consumption for Reheating Flue Gas:
> Unit 1 Low Dust SCR System 31 MMBtu/hr
> Unit 1 Tail End SCR System 60.3 MMBtu/hr
> Unit 2 Low Dust SCR System 96.2 MMBtu/hr
> Unit 2 Tail End SCR System 101.6 MMBtu/hr

Estimated Natural Gas Consumption for Urea to Ammonia Conversion:
> Unit 1 SCR System 4.3 MMBtu/hr
> Unit 2 SCR System 6.7 MMBtu/hr

The NDDH technical lead person wanted to know if Unit 2's low dust gas for reheat was correct, as it appears to be much closer to the natural gas consumption for tail end than when comparing Unit 1's LD to TESCR natural gas numbers. We told him we also noticed this difference in proportion but didn't know what numbers may be in need of revision.

We ask that you review the preliminary process design numbers for reheat fuel (and Ultra system fuel) in all four SCR cases by January 7th, so we can respond back to the NDDH on this issue, as it affects the cost effectiveness analysis for these alternatives in the updated BACT studies.

Hope you are getting a change to enjoy time with your families this holiday season.

Merry Christmas.

Bob Blakley

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Monday, September 28, 2009 10:05 AM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: 28Sep_PFD Revisions

Bob,
Attached are the revised PFDs.
I added a summary line to the mass balance table, and all of the flows match those on the flow diagram.
The balance around the ULTRA system for the U1 systems has been corrected.

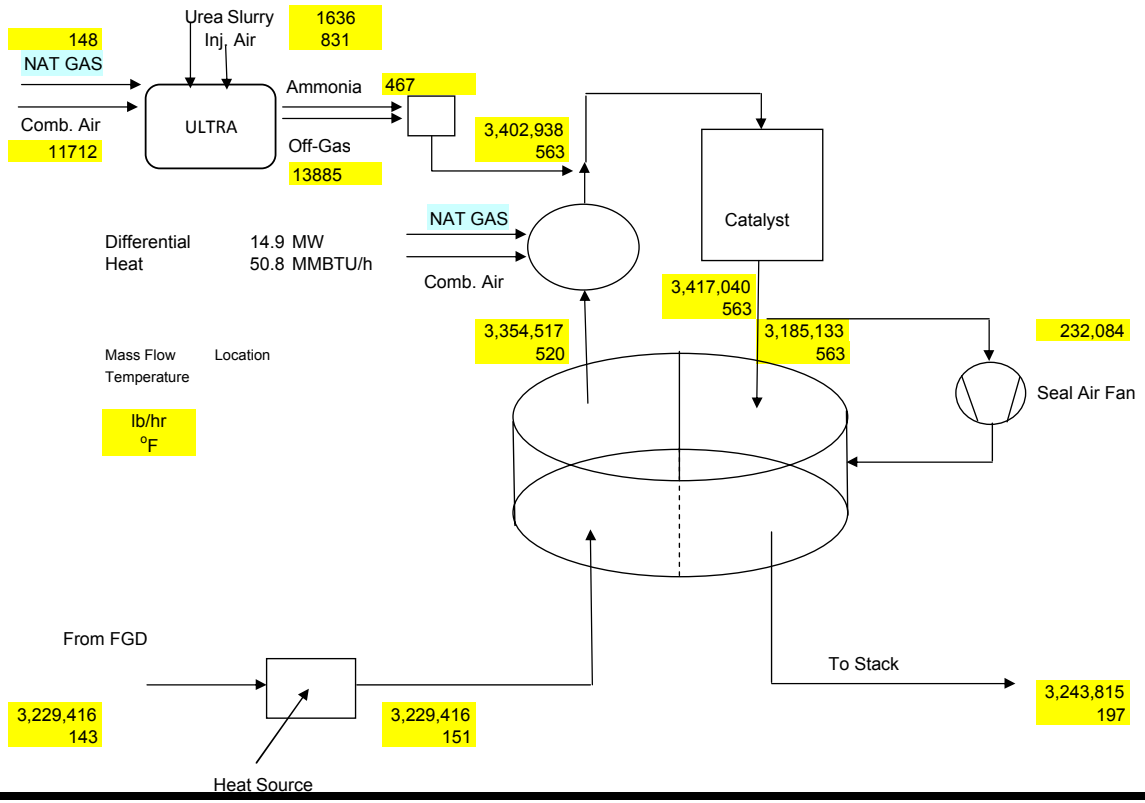
Please let us know if we can clarify anything.
Best Regards, Bob

Robert E. Johnson
Fuel Tech, Inc
(913) 897 0727

This message contains information that may be privileged, confidential or otherwise protected from disclosure. Unless you are the intended addressee (or authorized recipient for the addressee) you may not use, copy or disclose this message or information contained in this message to anyone. If you received this message in error, please notify the sender by replying to this message and then delete it from your system without copying or disclosing it. Thank you.

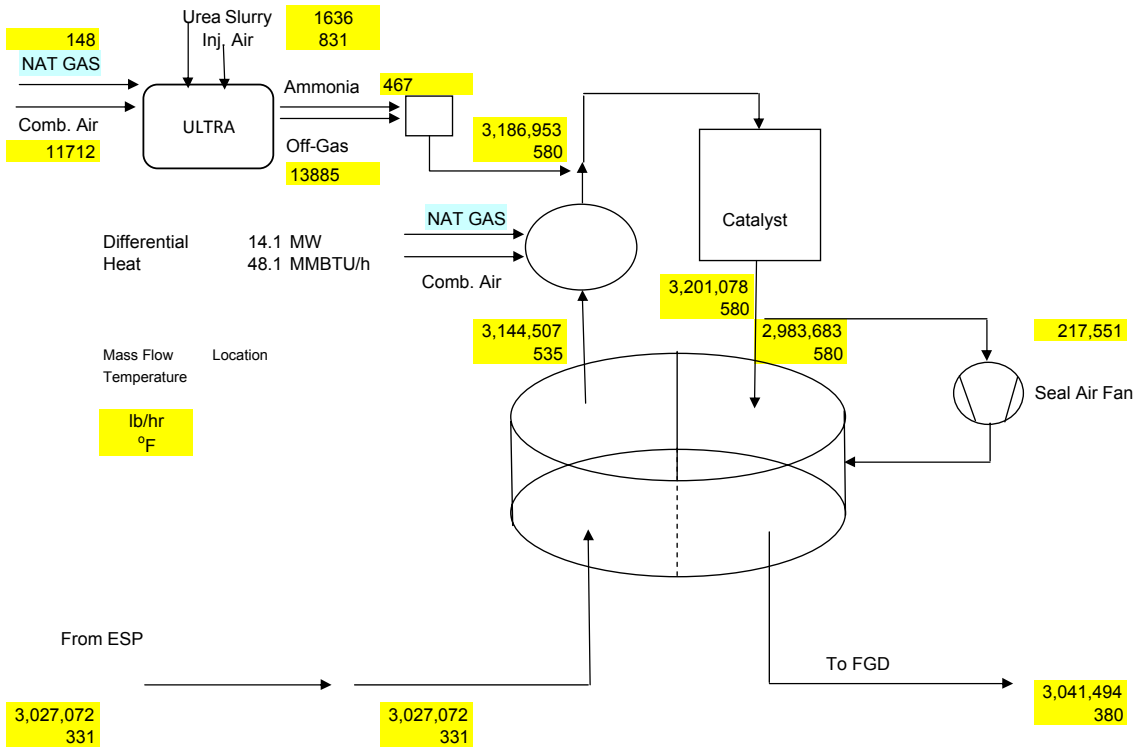
<<28Sep09_MRY2TailEnd_Rev2_natgas.pdf>> <<27Sep09_BMcD for MRYS_Additional Process Data_R2.doc>> <<28Sep09_MRY1LowDust_Rev3_natgas_580F.pdf>> <<28Sep09_MRY1TailEnd_Rev4_natgas.pdf>> <<28Sep09_MRY2LowDust_Rev2_natgas_580F.pdf>>

MRY 2 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



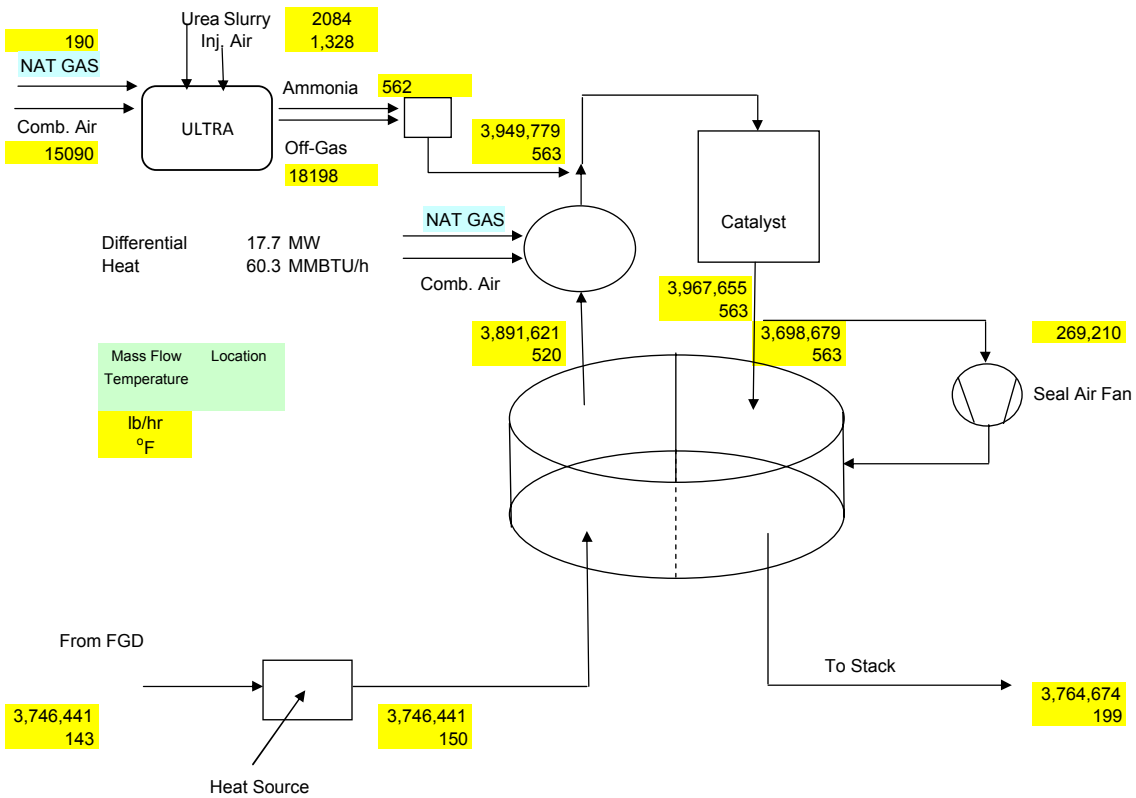
		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Stack
Nitrogen	lb/h	2,063,089	2,063,089	2,143,074	2,180,720	2,190,102	2,191,257	2,042,589	2,073,613
Carbon di oxide	lb/h	542,901	542,901	563,862	569,261	570,275	570,275	531,584	543,915
Oxygen	lb/h	184,328	184,328	191,496	192,317	194,562	194,123	180,952	185,704
Moisture	lb/h	437,137	437,137	454,101	458,641	459,743	460,485	429,243	439,707
Sulfur di oxide	lb/h	496	496	514	514	514	509	475	491
Sulfur tri oxide	lb/h	0	0	0	0	0	6	6	6
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,389	1,389	1,381	1,397	1,397	132	123	139
Argon	lb/h	0	0	8	8	167	167	156	159
Ammonia	lb/h	0	0	0	0	468	5	5	5
Particulate	lb/h	77	77	80	80	80	80	0	77
Total	lb/h	3,229,416	3,229,416	3,354,517	3,402,938	3,417,308	3,417,040	3,185,133	3,243,815

MRY 2 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



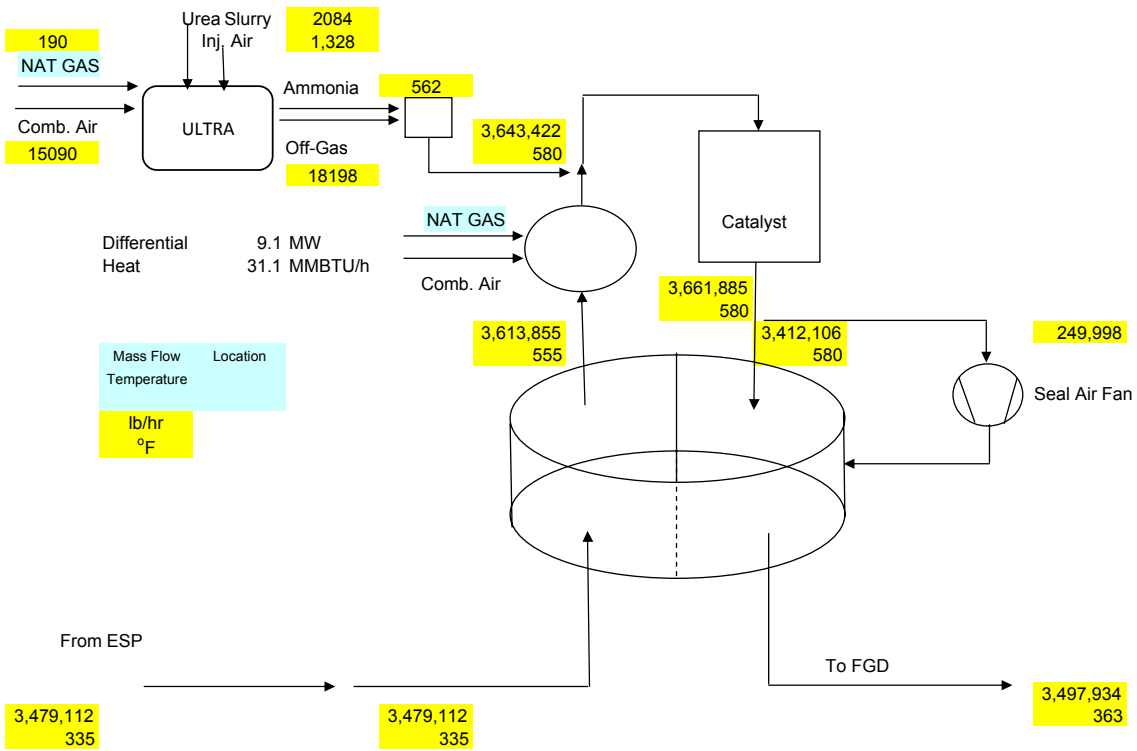
		ESP Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	FGD Inlet
Nitrogen	lb/h	2,031,828	2,031,828	2,110,694	2,143,695	2,153,077	2,154,231	2,007,981	2,042,352
Carbon di oxide	lb/h	536,419	536,419	557,153	561,885	562,899	562,899	524,684	537,433
Oxygen	lb/h	177,258	177,258	184,161	184,881	187,126	186,686	174,012	178,633
Moisture	lb/h	270,167	270,167	280,712	284,691	285,793	286,535	267,082	272,738
Sulfur di oxide	lb/h	9,934	9,934	10,312	10,312	10,312	10,213	9,519	9,835
Sulfur tri oxide	lb/h	0	0	6	6	6	130	121	124
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,389	1,389	1,381	1,395	1,395	132	123	139
Argon	lb/h	0	0	8	8	167	167	156	159
Ammonia	lb/h	0	0	0	0	468	5	4	5
Particulate	lb/h	77	77	80	80	80	80	0	77
Total	lb/h	3,027,072	3,027,072	3,144,507	3,186,953	3,201,323	3,201,078	2,983,683	3,041,494

MRY 1 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated	Stack
Nitrogen	lb/h	2,371,943	2,371,943	2,463,945	2,509,161	2,521,083	2,522,472	2,351,512	2,385,237
Carbon di oxide	lb/h	622,053	622,053	646,071	652,555	653,815	653,815	609,503	623,313
Oxygen	lb/h	213,652	213,652	221,970	222,956	225,821	225,293	210,023	215,472
Moisture	lb/h	536,485	536,485	557,301	562,753	564,141	565,034	526,739	539,638
Sulfur di oxide	lb/h	568	568	590	590	590	584	545	563
Sulfur tri oxide	lb/h	0	0	0	0	0	7	7	7
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,670	1,670	1,660	1,679	1,679	159	148	167
Argon	lb/h	0	0	10	10	211	211	197	201
Ammonia	lb/h	0	0	0	0	563	6	6	6
Particulate	lb/h	70	70	73	73	73	73	0	70
Total	lb/hr	3,746,441	3,746,441	3,891,621	3,949,779	3,967,977	3,967,655	3,698,679	3,764,674

MRY 1 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



		ESP Outlet	GGH inlet	GGH outlet	Burner out	Catalyst Inlet	Catalyst Outlet	GGH treated	FGD Inlet
Nitrogen	lb/hr	2,336,123	2,336,123	2,426,651	2,449,638	2,461,951	2,463,331	2,295,352	2,349,809
Carbon di oxide	lb/hr	614,626	614,626	638,330	641,626	642,928	642,928	599,086	615,928
Oxygen	lb/hr	205,551	205,551	213,551	214,052	217,009	216,484	201,722	207,463
Moisture	lb/hr	309,692	309,692	321,760	324,532	325,950	326,837	304,550	312,875
Sulfur di oxide	lb/hr	11,381	11,381	11,813	11,813	11,813	11,699	10,902	11,267
Sulfur tri oxide	lb/hr	0	0	7	7	7	149	139	142
Nitrogen oxide	lb/hr	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/hr	1,670	1,670	1,660	1,670	1,670	159	148	167
Argon	lb/hr	0	0	10	10	218	218	203	208
Ammonia	lb/hr	0	0	0	0	562	5	5	5
Particulate	lb/hr	70	70	73	73	73	73	0	70
Total	lb/hr	3,479,112	3,479,112	3,613,855	3,643,422	3,662,182	3,661,885	3,412,106	3,497,934

Burns & McDonnell for Minnkota Power
Milton Young Station

Low Dust & Tail End Selective Catalytic Reduction (SCR) Systems
Additional Mass Balance Data (Rev 2)

		Unit 1 Low Dust	**Unit 1 Tail End**	**Unit 2 Low Dust (per reactor)**	**Unit 2 Tail End (per reactor)**
Reheat Natural Gas	MMBtu/hr	31.1	60.3	48.1	50.8
Reheat Natural Gas	scfm	491	965	704	803
Burner System	% Air				
Burner System	Air Lb/hr	28,221	55,490	40,514	46,216
ULTRA System Natural Gas	MMBtu/hr	4.27	4.27	3.33	3.33
ULTRA System Natural Gas	scfm	70	70	54	54
NOx Reheat Natural Gas	Lb/hr	10	20	14	16
NOx ULTRA Natural Gas	Lb/hr	1.5	1.5	1.1	1.1
Reactor Total Efficiency	%	90.49	90.54	90.53	90

Blakley, Robert

From: Blakley, Robert
Sent: Wednesday, January 06, 2010 2:45 PM
To: 'Wayne Jones'
Cc: Weilert, Carl
Subject: RE: Investigation of Hypothetical Application of TESCR and LDSCR, Minnkota Power Cooperative Milton R. Young Station Units 1 & 2
Attachments: HT Jan 06_2010 (signed).pdf

Wayne:

Confirming my voice mail message of January 6, 2010. Please call me when you have a chance.

We are asking for review of our attached letter with written confirmation regarding stating Haldor Topsoe's catalyst life guarantee being contingent upon successful completion of pilot-scale slipstream testing that confirm catalyst deactivation and fouling rates of the studied hypothetical applications of tail end and low-dust SCRs for Units 1 and 2 at Milton R. Young Station for Minnkota Power Cooperative.

Robert D. Blakley, P.E.

Associate Project Engineer
(Currently registered and licensed in North Dakota)
Burns & McDonnell
Energy Group
9400 Ward Parkway
Kansas City, MO 64114
Direct: 816-822-3842
Main: 816-333-9400
Fax: 816-333-3690
rblakley@burnsmcd.com
www.burnsmcd.com

Burns & McDonnell
SINCE 1898

January 6, 2010

Mr. Wayne Jones
Haldor Topsoe, Inc.
17629 El Camino Real
Suite 300
Houston, Texas 77058

Minnkota Power Cooperative Milton R. Young Station Units 1 & 2
Investigation of Hypothetical Application of TESCR and LDSCR
BMcD Project 31777

Dear Mr. Jones:

Burns & McDonnell has prepared supplemental reports for the NOx BACT analyses for Milton R. Young Station (MRYS) Units 1 and 2, and these reports have been submitted by Minnkota Power Cooperative to the North Dakota Department of Health. In the text of these reports, we stated that:

> During preparation of the cost estimate, Burns & McDonnell consulted with two SCR catalyst vendors experienced with biomass-fired boiler SCRs and European coal-fired boilers with low-dust and tail end SCR systems. However, neither of these vendors was willing to guarantee a catalyst replacement schedule for cyclone boilers firing North Dakota lignite without results following successful extensive pilot-scale slipstream testing that confirm the deactivation and fouling rates. According to these catalyst suppliers, there is no SCR operating experience in the world found to be directly comparable to the hypothetically applied tail end and low-dust SCR cases on North Dakota lignite-fired cyclone boilers being evaluated. Thus they were unable to offer a guaranteed catalyst replacement schedule based on their experience.

Please review this statement and respond in writing to confirm that we have correctly stated your company's position on catalyst life guarantees for the application of SCR systems to MRYS Units 1 & 2 without successful completion of pilot testing.

Sincerely,

Robert D. Blakley

Robert D Blakley, P.E.
Project Engineer

9400 Ward Parkway
Kansas City, Missouri 64114-3319
Tel: 816-333-9400
Fax: 816-333-3690
http://www.burnsmcd.com

Blakley, Robert

From: Blakley, Robert

Sent: Wednesday, January 06, 2010 2:48 PM

To: 'Noel.Rosha@ceram-usa.com'

Cc: Weilert, Carl

Subject: RE: Investigation of Hypothetical Application of TESCR and LDSCR, Minnkota Power Cooperative Milton R. Young Station Units 1 & 2

Noel:

Confirming our phone conversation of January 6, 2010.

We are asking for review of our attached letter with written confirmation regarding stating CERAM-USA's catalyst life guarantee being contingent upon successful completion of pilot-scale slipstream testing that confirm catalyst deactivation and fouling rates of the studied hypothetical applications of tail end and low-dust SCRs for Units 1 and 2 at Milton R. Young Station for Minnkota Power Cooperative.

Robert D. Blakley, P.E.

Associate Project Engineer
(Currently registered and licensed in North Dakota)
Burns & McDonnell
Energy Group
9400 Ward Parkway
Kansas City, MO 64114
Direct: 816-822-3842
Main: 816-333-9400
Fax: 816-333-3690
rblakley@burnsmcd.com
www.burnsmcd.com

Burns & McDonnell
SINCE 1898

January 6, 2010

Mr. Noel Rosha
CERAM Environmental, Inc.
7304 W. 130th St.
Suite 140
Overland Park, Kansas 66213

Minnkota Power Cooperative Milton R. Young Station Units 1 & 2
Investigation of Hypothetical Application of TESCR and LDSCR
BMcD Project 31777

Dear Mr. Rosha:

Burns & McDonnell has prepared supplemental reports for the NOx BACT analyses for Milton R. Young Station (MRYS) Units 1 and 2, and these reports have been submitted by Minnkota Power Cooperative to the North Dakota Department of Health. In the text of these reports, we stated that:

> During preparation of the cost estimate, Burns & McDonnell consulted with two SCR catalyst vendors experienced with biomass-fired boiler SCRs and European coal-fired boilers with low-dust and tail end SCR systems. However, neither of these vendors was willing to guarantee a catalyst replacement schedule for cyclone boilers firing North Dakota lignite without results following successful extensive pilot-scale slipstream testing that confirm the deactivation and fouling rates. According to these catalyst suppliers, there is no SCR operating experience in the world found to be directly comparable to the hypothetically applied tail end and low-dust SCR cases on North Dakota lignite-fired cyclone boilers being evaluated. Thus they were unable to offer a guaranteed catalyst replacement schedule based on their experience.

Please review this statement and respond in writing to confirm that we have correctly stated your company's position on catalyst life guarantees for the application of SCR systems to MRYS Units 1 & 2 without successful completion of pilot testing.

Sincerely,

Robert D. Blakley

Robert D Blakley, P.E.
Project Engineer

9400 Ward Parkway
Kansas City, Missouri 64114-3319
Tel: 816-333-9400
Fax: 816-333-3690
http://www.burnsmcd.com

Blakley, Robert

From: Blakley, Robert
Sent: Monday, January 11, 2010 1:03 PM
To: Volker Rummenhohl
Cc: 51684; Bryant, Ronald; Weilert, Carl; Blackwood, Dave
Subject: FW: 28Sep_PFD Revisions
Attachments: 28Sep09_MRY2TailEnd_Rev2_natgas.pdf; 27Sep09_BMcD for MRYS_Additional Process Data_R2.doc; 28Sep09_MRY1LowDust_Rev3_natgas_580F.pdf; 28Sep09_MRY1TailEnd_Rev4_natgas.pdf; 28Sep09_MRY2LowDust_Rev2_natgas_580F.pdf

Volker -

I am resending this email from 12/22, seeking your assistance in confirming the natural gas consumption rates for all four cases studied (see below and attached).

We are now on a tight timeline for response back to Minnkota for providing the correct numbers and any revised BACT Analysis ($ per ton) so they can respond the the State of North Dakota's Health Department - Air Quality Division.

Please advise you can confirm the process design as regards natural gas rates by 1/15/10.

Thanks,

Robert D. Blakley, P.E.

Associate Project Engineer
(Currently registered and licensed in North Dakota)
Energy Group
9400 Ward Parkway
Kansas City, MO 64114
Direct: 816-822-3842
Main: 816-333-9400
Fax: 816-333-3690
rblakley@burnsmcd.com
www.burnsmcd.com

---

ey, Robert
Sent: Tuesday, December 22, 2009 9:21 AM
To: 'Robert Johnson'
Cc: 49861; Volker Rummenhohl; Blackwood, Dave; Bryant, Ronald; Weilert, Carl
Subject: FW: 28Sep_PFD Revisions

Bob -

Carl Weilert and I reviewed information involving hypothetical applications of tail end and low dust SCR technologies at Minnkota's Milton R. Young Station with the North Dakota Department of Health's Air Quality Division on Monday, December 21, 2009.

Estimated Natural Gas Consumption for Reheating Flue Gas:
> Unit 1 Low Dust SCR System 31 MMBtu/hr
> Unit 1 Tail End SCR System 60.3 MMBtu/hr
> Unit 2 Low Dust SCR System 96.2 MMBtu/hr

> Unit 2 Tail End SCR System 101.6 MMBtu/hr

Estimated Natural Gas Consumption for Urea to Ammonia Conversion:
> Unit 1 SCR System 4.3 MMBtu/hr
> Unit 2 SCR System 6.7 MMBtu/hr

The NDDH technical lead person wanted to know if Unit 2's low dust gas for reheat was correct, as it appears to be much closer to the natural gas consumption for tail end than when comparing Unit 1's LD to TESCR natural gas numbers. We told him we also noticed this difference in proportion but didn't know what numbers may be in need of revision.

We ask that you review the preliminary process design numbers for reheat fuel (and Ultra system fuel) in all four SCR cases by January 7th, so we can respond back to the NDDH on this issue, as it affects the cost effectiveness analysis for these alternatives in the updated BACT studies.

Hope you are getting a change to enjoy time with your families this holiday season.

Merry Christmas.

Bob Blakley

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Monday, September 28, 2009 10:05 AM
To: Blakley, Robert
Cc: Volker Rummenhohl
Subject: 28Sep_PFD Revisions

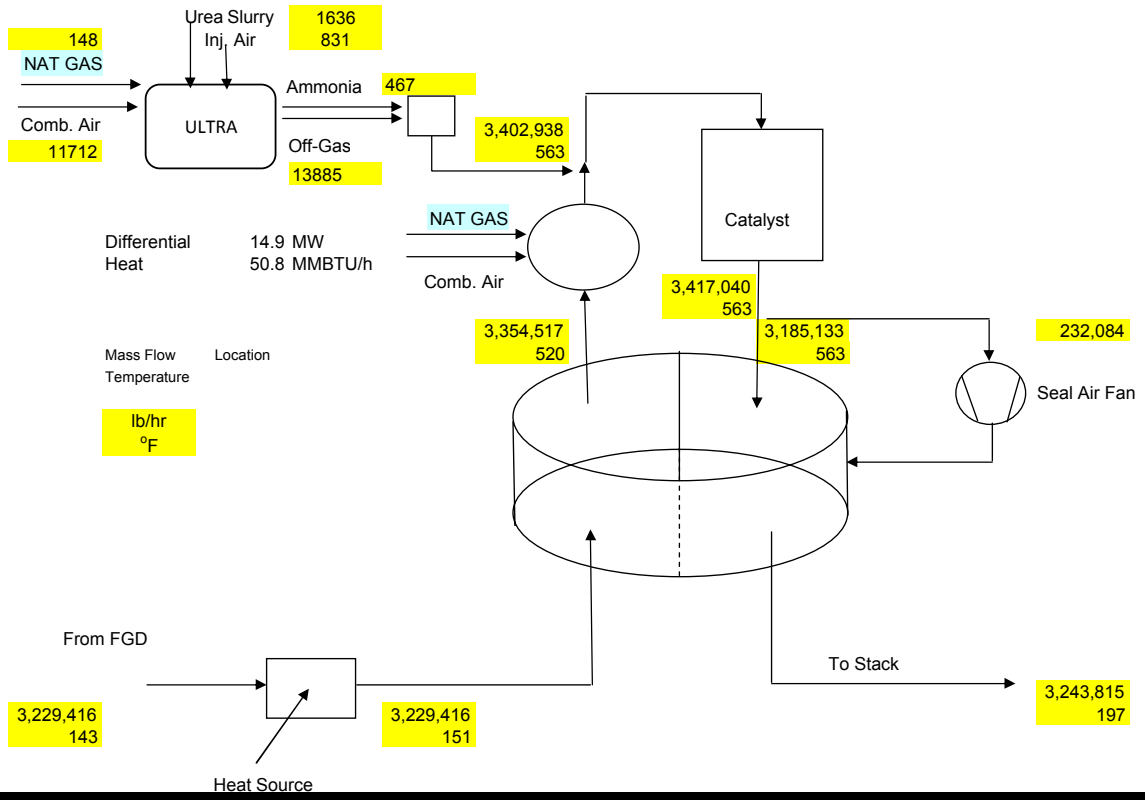
Bob,
Attached are the revised PFDs.
I added a summary line to the mass balance table, and all of the flows match those on the flow diagram.
The balance around the ULTRA system for the U1 systems has been corrected.
Please let us know if we can clarify anything.
Best Regards, Bob

Robert E. Johnson
Fuel Tech, Inc
(913) 897 0727

This message contains information that may be privileged, confidential or otherwise protected from disclosure. Unless you are the intended addressee (or authorized recipient for the addressee) you may not use, copy or disclose this message or information contained in this message to anyone. If you received this message in error, please notify the sender by replying to this message and then delete it from your system without copying or disclosing it. Thank you.

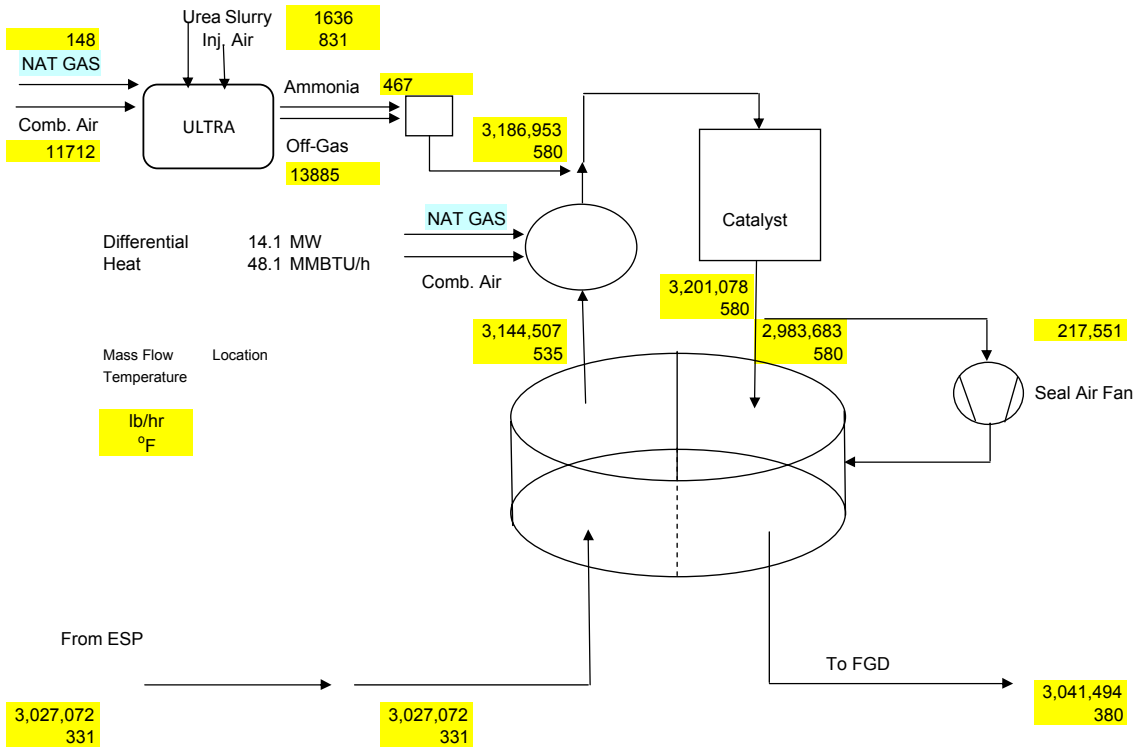
<<28Sep09_MRY2TailEnd_Rev2_natgas.pdf>> <<27Sep09_BMcD for MRYS_Additional Process Data_R2.doc>> <<28Sep09_MRY1LowDust_Rev3_natgas_580F.pdf>> <<28Sep09_MRY1TailEnd_Rev4_natgas.pdf>> <<28Sep09_MRY2LowDust_Rev2_natgas_580F.pdf>>

MRY 2 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



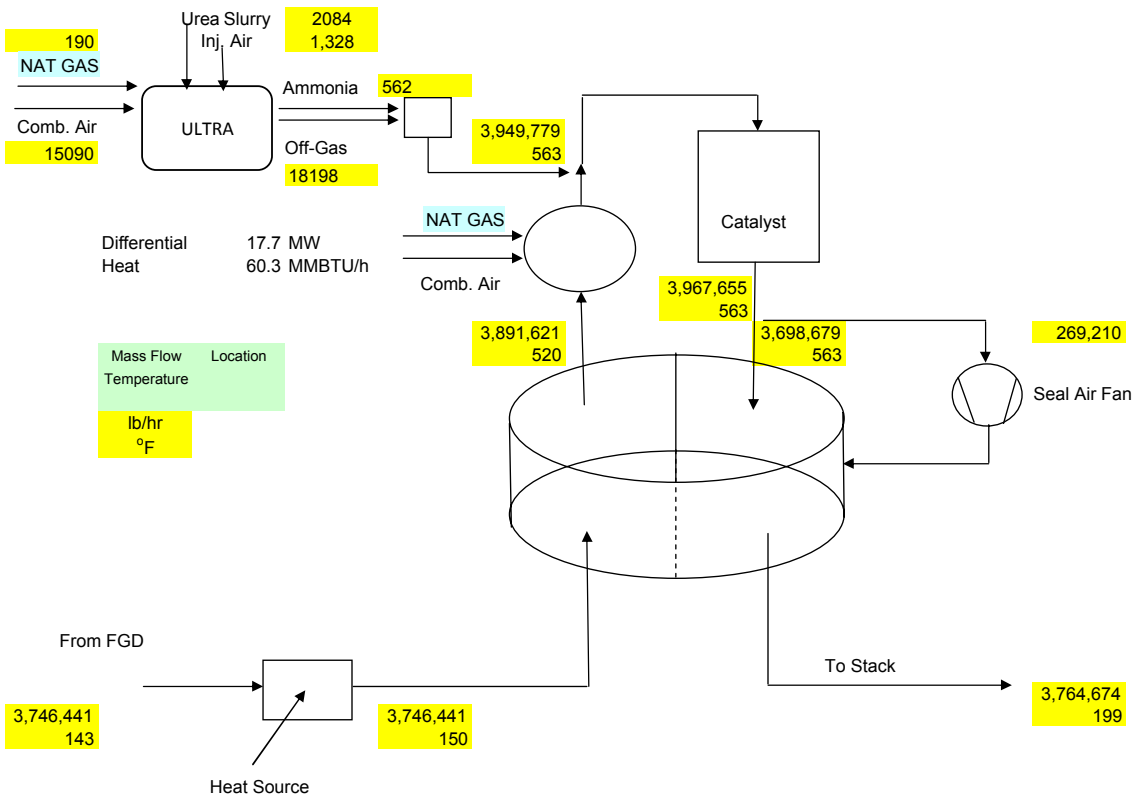
		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	Stack
Nitrogen	lb/h	2,063,089	2,063,089	2,143,074	2,180,720	2,190,102	2,191,257	2,042,589	2,073,613
Carbon di oxide	lb/h	542,901	542,901	563,862	569,261	570,275	570,275	531,584	543,915
Oxygen	lb/h	184,328	184,328	191,496	192,317	194,562	194,123	180,952	185,704
Moisture	lb/h	437,137	437,137	454,101	458,641	459,743	460,485	429,243	439,707
Sulfur di oxide	lb/h	496	496	514	514	514	509	475	491
Sulfur tri oxide	lb/h	0	0	0	0	0	6	6	6
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,389	1,389	1,381	1,397	1,397	132	123	139
Argon	lb/h	0	0	8	8	167	167	156	159
Ammonia	lb/h	0	0	0	0	468	5	5	5
Particulate	lb/h	77	77	80	80	80	80	0	77
Total	lb/h	3,229,416	3,229,416	3,354,517	3,402,938	3,417,308	3,417,040	3,185,133	3,243,815

MRY 2 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat (per Reactor)



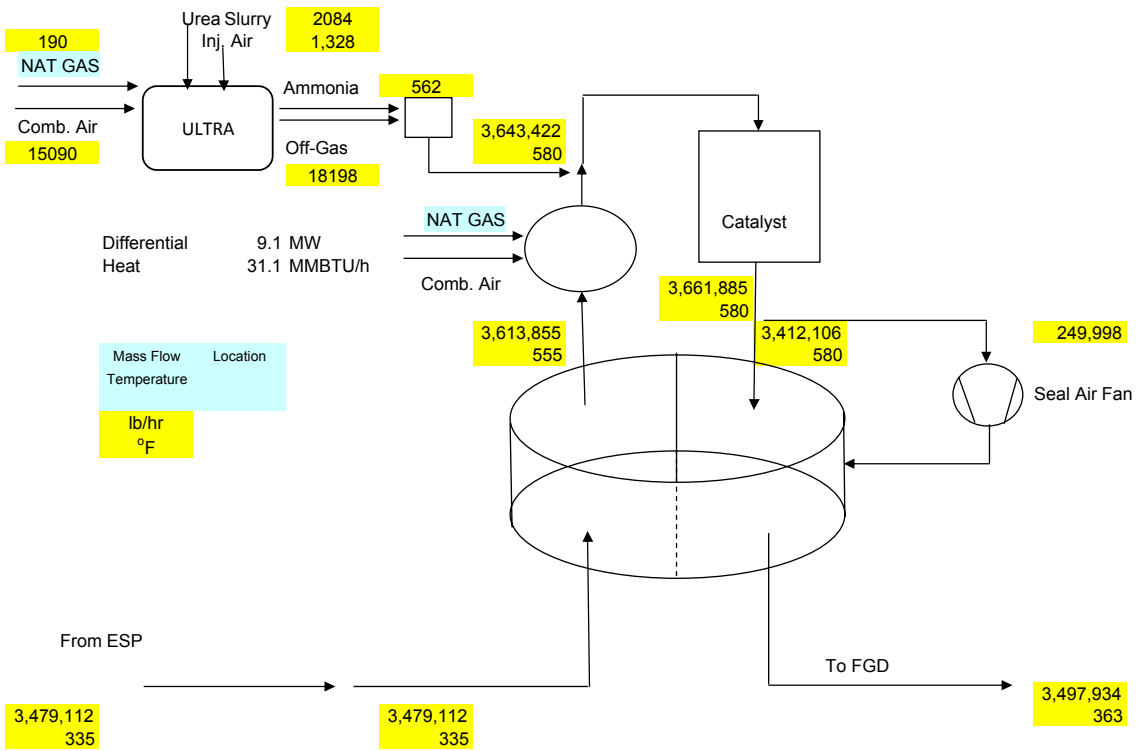
		ESP Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated inlet	FGD Inlet
Nitrogen	lb/h	2,031,828	2,031,828	2,110,694	2,143,695	2,153,077	2,154,231	2,007,981	2,042,352
Carbon di oxide	lb/h	536,419	536,419	557,153	561,885	562,899	562,899	524,684	537,433
Oxygen	lb/h	177,258	177,258	184,161	184,881	187,126	186,686	174,012	178,633
Moisture	lb/h	270,167	270,167	280,712	284,691	285,793	286,535	267,082	272,738
Sulfur di oxide	lb/h	9,934	9,934	10,312	10,312	10,312	10,213	9,519	9,835
Sulfur tri oxide	lb/h	0	0	6	6	6	130	121	124
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,389	1,389	1,381	1,395	1,395	132	123	139
Argon	lb/h	0	0	8	8	167	167	156	159
Ammonia	lb/h	0	0	0	0	468	5	4	5
Particulate	lb/h	77	77	80	80	80	80	0	77
Total	lb/h	3,027,072	3,027,072	3,144,507	3,186,953	3,201,323	3,201,078	2,983,683	3,041,494

MRY 1 Tail End SCR Process Flow Diagram Natural Gas Fired Reheat



		FGD Outlet	GGH inlet	GGH outlet	Burner out	Reactor inlet	Reactor outlet	GGH treated	Stack
Nitrogen	lb/h	2,371,943	2,371,943	2,463,945	2,509,161	2,521,083	2,522,472	2,351,512	2,385,237
Carbon di oxide	lb/h	622,053	622,053	646,071	652,555	653,815	653,815	609,503	623,313
Oxygen	lb/h	213,652	213,652	221,970	222,956	225,821	225,293	210,023	215,472
Moisture	lb/h	536,485	536,485	557,301	562,753	564,141	565,034	526,739	539,638
Sulfur di oxide	lb/h	568	568	590	590	590	584	545	563
Sulfur tri oxide	lb/h	0	0	0	0	0	7	7	7
Nitrogen oxide	lb/h	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/h	1,670	1,670	1,660	1,679	1,679	159	148	167
Argon	lb/h	0	0	10	10	211	211	197	201
Ammonia	lb/h	0	0	0	0	563	6	6	6
Particulate	lb/h	70	70	73	73	73	73	0	70
Total	lb/hr	3,746,441	3,746,441	3,891,621	3,949,779	3,967,977	3,967,655	3,698,679	3,764,674

MRY 1 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



		ESP Outlet	GGH inlet	GGH outlet	Burner out	Catalyst Inlet	Catalyst Outlet	GGH treated	FGD Inlet
Nitrogen	lb/hr	2,336,123	2,336,123	2,426,651	2,449,638	2,461,951	2,463,331	2,295,352	2,349,809
Carbon di oxide	lb/hr	614,626	614,626	638,330	641,626	642,928	642,928	599,086	615,928
Oxygen	lb/hr	205,551	205,551	213,551	214,052	217,009	216,484	201,722	207,463
Moisture	lb/hr	309,692	309,692	321,760	324,532	325,950	326,837	304,550	312,875
Sulfur di oxide	lb/hr	11,381	11,381	11,813	11,813	11,813	11,699	10,902	11,267
Sulfur tri oxide	lb/hr	0	0	7	7	7	149	139	142
Nitrogen oxide	lb/hr	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/hr	1,670	1,670	1,660	1,670	1,670	159	148	167
Argon	lb/hr	0	0	10	10	218	218	203	208
Ammonia	lb/hr	0	0	0	0	562	5	5	5
Particulate	lb/hr	70	70	73	73	73	73	0	70
Total	lb/hr	3,479,112	3,479,112	3,613,855	3,643,422	3,662,182	3,661,885	3,412,106	3,497,934

Burns & McDonnell for Minnkota Power
Milton Young Station

Low Dust & Tail End Selective Catalytic Reduction (SCR) Systems
Additional Mass Balance Data (Rev 2)

		Unit 1 Low Dust	**Unit 1 Tail End**	**Unit 2 Low Dust (per reactor)**	**Unit 2 Tail End (per reactor)**
Reheat Natural Gas	MMBtu/hr	31.1	60.3	48.1	50.8
Reheat Natural Gas	scfm	491	965	704	803
Burner System	% Air				
Burner System	Air Lb/hr	28,221	55,490	40,514	46,216
ULTRA System Natural Gas	MMBtu/hr	4.27	4.27	3.33	3.33
ULTRA System Natural Gas	scfm	70	70	54	54
NOx Reheat Natural Gas	Lb/hr	10	20	14	16
NOx ULTRA Natural Gas	Lb/hr	1.5	1.5	1.1	1.1
Reactor Total Efficiency	%	90.49	90.54	90.53	90

Blakley, Robert

From: Noel Rosha [Noel.Rosha@ceram-usa.com]
Sent: Wednesday, January 13, 2010 3:02 PM
To: Blakley, Robert
Cc: Weilert, Carl
Subject: RE: Investigation of Hypothetical Application of TESCR and LDSCR, Minnkota Power Cooperative Milton R. Young Station Units 1 & 2
Attachments: CERAM Jan 06_2010 (signed).pdf

Robert,

CERAM confirms that the attached letter accurately reflects our position regarding catalyst life guarantees for the Milton R. Young Station tail end and low-dust SCR applications.

Best regards,

Noel Rosha, P.E.
Senior Applications Engineer

CERAM Environmental, Inc.
Phone: 913-239-9896
Mobile: 913-638-9672

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Wednesday, January 06, 2010 2:48 PM
To: Noel Rosha
Cc: Weilert, Carl
Subject: RE: Investigation of Hypothetical Application of TESCR and LDSCR, Minnkota Power Cooperative Milton R. Young Station Units 1 & 2

Noel:
Confirming our phone conversation of January 6, 2010.
We are asking for review of our attached letter with written confirmation regarding stating CERAM-USA's catalyst life guarantee being contingent upon successful completion of pilot-scale slipstream testing that confirm catalyst deactivation and fouling rates of the studied hypothetical applications of tail end and low-dust SCRs for Units 1 and 2 at Milton R. Young Station for Minnkota Power Cooperative.

Robert D. Blakley, P.E.
Associate Project Engineer
(Currently registered and licensed in North Dakota)
Burns & McDonnell
Energy Group
9400 Ward Parkway
Kansas City, MO 64114
Direct: 816-822-3842
Main: 816-333-9400
Fax: 816-333-3690
rblakley@burnsmcd.com
www.burnsmcd.com

Burns & McDonnell
SINCE 1898

January 6, 2010

Mr. Noel Rosha
CERAM Environmental, Inc.
7304 W. 130th St.
Suite 140
Overland Park, Kansas 66213

Minnkota Power Cooperative Milton R. Young Station Units 1 & 2
Investigation of Hypothetical Application of TESCR and LDSCR
BMcD Project 31777

Dear Mr. Rosha:

Burns & McDonnell has prepared supplemental reports for the NOx BACT analyses for Milton R. Young Station (MRYS) Units 1 and 2, and these reports have been submitted by Minnkota Power Cooperative to the North Dakota Department of Health. In the text of these reports, we stated that:

> During preparation of the cost estimate, Burns & McDonnell consulted with two SCR catalyst vendors experienced with biomass-fired boiler SCRs and European coal-fired boilers with low-dust and tail end SCR systems. However, neither of these vendors was willing to guarantee a catalyst replacement schedule for cyclone boilers firing North Dakota lignite without results following successful extensive pilot-scale slipstream testing that confirm the deactivation and fouling rates. According to these catalyst suppliers, there is no SCR operating experience in the world found to be directly comparable to the hypothetically applied tail end and low-dust SCR cases on North Dakota lignite-fired cyclone boilers being evaluated. Thus they were unable to offer a guaranteed catalyst replacement schedule based on their experience.

Please review this statement and respond in writing to confirm that we have correctly stated your company's position on catalyst life guarantees for the application of SCR systems to MRYS Units 1 & 2 without successful completion of pilot testing.

Sincerely,

Robert D. Blakley

Robert D Blakley, P.E.
Project Engineer

9400 Ward Parkway
Kansas City, Missouri 64114-3319
Tel: 816-333-9400
Fax: 816-333-3690
http://www.burnsmcd.com

Blakley, Robert

From: Wayne Jones [WSJ@topsoe.com]
Sent: Wednesday, January 13, 2010 5:29 PM
To: Blakley, Robert
Cc: Weilert, Carl; TNW@topsoe.com; CAW@topsoe.com
Subject: RE: Investigation of Hypothetical Application of TESCR and LDSCR, Minnkota Power Cooperative Milton R. Young Station Units 1 & 2
Attachments: HT Jan 06_2010 (signed).pdf; Microsoft Word - WSJ Letter 1-07-2010 on HTI Letterhead.pdf

Robert,

Please find attached below your requested letter defining HTI's position with respect to providing a catalyst guaranteed life on either Unit 1 or Unit 2 at Minnkota's Milton R. Young station. If you have any questions please let me know.

Regards,
Wayne

Wayne S. Jones
Sales Manager, Power Generation
Haldor Topsoe, Inc.
281-228-5136 (office)
281-228-5129 (fax)
281-684-8811 (cell)
wsj@topsoe.com
www.HaldorTopsoe.com

"Blakley, Robert" <rblakley@burnsmcd.com>

01/06/2010 02:45 PM

To Wayne Jones <WSJ@topsoe.com>
cc "Weilert, Carl" <cweiler@burnsmcd.com>
Subject RE: Investigation of Hypothetical Application of TESCR and LDSCR, Minnkota Power Cooperative Milton R. Young Station Units 1 & 2

Wayne:

Confirming my voice mail message of January 6, 2010. Please call me when you have a chance.

We are asking for review of our attached letter with written confirmation regarding stating Haldor Topsoe's catalyst life guarantee being contingent upon successful completion of pilot-scale slipstream testing that confirm catalyst deactivation and fouling rates of the studied hypothetical applications of tail end and low-dust SCRs for Units 1 and 2 at Milton R. Young Station for Minnkota Power Cooperative.

Robert D. Blakley, P.E.

Associate Project Engineer
(Currently registered and licensed in North Dakota)
Burns & McDonnell
Energy Group
9400 Ward Parkway
Kansas City, MO 64114
Direct: 816-822-3842
Main: 816-333-9400
Fax: 816-333-3690
rblakley@burnsmcd.com
www.burnsmcd.com

HALDOR TOPSØE

Haldor Topsoe, Inc.
17629 El Camino Real
Suite 300
Houston, Texas 77058
www.topsoe.com

Tel: (281) 228-5000
Fax: (281) 228-5019

January 13, 2010

Mr. Robert D. Blakley, P.E.
Burns & McDonnell
9400 Ward Parkway
Kansas City, Missouri 64114

Minnkota Power Cooperative, Milton R. Young Units 1&2
Investigation of Hypothetical Application of TESCR and LDSCR
BMcD project 31777

Mr. Blakley,

This letter is to confirm that it is my understanding, based on the information currently at hand, that Haldor Topsoe, Inc would consider providing a SCR catalyst life guarantee for either Milton R. Young Unit 1 or Unit 2 for either a tail end (TESCR) or low dust (LDSCR) configuration only following the successful completion of a pilot-scale slipstream test of our SCR catalyst on one of the two MRY units. The issuance of a SCR catalyst life guarantee, if any, would be for only the configuration tested during the pilot-scale testing.

If you have any question please feel free to contact me at 281-228-5136

Sincerely,

Wayne S. Jones
Sales Manager, Power Generation
SCR/DeNOx Catalyst & Technology

Burns & McDonnell
SINCE 1898

January 6, 2010

Mr. Wayne Jones
Haldor Topsoe, Inc.
17629 El Camino Real
Suite 300
Houston, Texas 77058

Minnkota Power Cooperative Milton R. Young Station Units 1 & 2
Investigation of Hypothetical Application of TESCR and LDSCR
BMcD Project 31777

Dear Mr. Jones:

Burns & McDonnell has prepared supplemental reports for the NOx BACT analyses for Milton R. Young Station (MRYS) Units 1 and 2, and these reports have been submitted by Minnkota Power Cooperative to the North Dakota Department of Health. In the text of these reports, we stated that:

> During preparation of the cost estimate, Burns & McDonnell consulted with two SCR catalyst vendors experienced with biomass-fired boiler SCRs and European coal-fired boilers with low-dust and tail end SCR systems. However, neither of these vendors was willing to guarantee a catalyst replacement schedule for cyclone boilers firing North Dakota lignite without results following successful extensive pilot-scale slipstream testing that confirm the deactivation and fouling rates. According to these catalyst suppliers, there is no SCR operating experience in the world found to be directly comparable to the hypothetically applied tail end and low-dust SCR cases on North Dakota lignite-fired cyclone boilers being evaluated. Thus they were unable to offer a guaranteed catalyst replacement schedule based on their experience.

Please review this statement and respond in writing to confirm that we have correctly stated your company's position on catalyst life guarantees for the application of SCR systems to MRYS Units 1 & 2 without successful completion of pilot testing.

Sincerely,

Robert D. Blakley

Robert D Blakley, P.E.
Project Engineer

9400 Ward Parkway
Kansas City, Missouri 64114-3319
Tel: 816-333-9400
Fax: 816-333-3690
http://www.burnsmcd.com

Blakley, Robert

From: Volker Rummenhohl [VRummenhohl@ftek.com]
Sent: Friday, January 15, 2010 9:14 AM
To: Blakley, Robert
Cc: 51684; Bryant, Ronald; Weilert, Carl; Blackwood, Dave; Robert Johnson; Julie Higgins
Subject: RE: 28Sep_PFD Revisions

Dear Bob,

Both Bob Johnson and I reviewed the calculations and I would like to confirm that we did not find any error. The only adjustment will come once to get the final GGH design, since this is an iterative process. The changes will be minor and the same for all options, the ratio between the options will not change.

Best regards,

Volker

Volker Rummenhohl
Vice President Catalyst Technologies
Fuel Tech, Inc.
2300 Englert Dr Ste C
Durham, NC 27713
Phone 919-484-1500
Cell 919-602-1063

This message contains information that may be privileged, confidential or otherwise protected from disclosure. Unless you are the intended addressee (or authorized recipient for the addressee) you may not use, copy or disclose this message or information contained in this message to anyone. If you received this message in error, please notify the sender by replying to this message and then delete it from your system without copying or disclosing it. Thank you.

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Monday, January 11, 2010 2:03 PM
To: Volker Rummenhohl
Cc: 51684; Bryant, Ronald; Weilert, Carl; Blackwood, Dave
Subject: FW: 28Sep_PFD Revisions

Volker -

I am resending this email from 12/22, seeking your assistance in confirming the natural gas consumption rates for all four cases studied (see below and attached).

We are now on a tight timeline for response back to Minnkota for providing the correct numbers and any revised BACT Analysis ($ per ton) so they can respond the the State of North Dakota's Health Department - Air Quality Division.

Please advise you can confirm the process design as regards natural gas rates by 1/15/10.

Thanks,

Robert D. Blakley, P.E.

Associate Project Engineer
(Currently registered and licensed in North Dakota)
Energy Group
9400 Ward Parkway
Kansas City, MO 64114
Direct: 816-822-3842
Main: 816-333-9400
Fax: 816-333-3690
rblakley@burnsmcd.com
www.burnsmcd.com

---

ey, Robert
Sent: Tuesday, December 22, 2009 9:21 AM
To: 'Robert Johnson'
Cc: 49861; Volker Rummenhohl; Blackwood, Dave; Bryant, Ronald; Weilert, Carl
Subject: FW: 28Sep_PFD Revisions

Bob -

Carl Weilert and I reviewed information involving hypothetical applications of tail end and low dust SCR technologies at Minnkota's Milton R. Young Station with the North Dakota Department of Health's Air Quality Division on Monday, December 21, 2009.

Estimated Natural Gas Consumption for Reheating Flue Gas:
> Unit 1 Low Dust SCR System 31 MMBtu/hr
> Unit 1 Tail End SCR System 60.3 MMBtu/hr
> Unit 2 Low Dust SCR System 96.2 MMBtu/hr
> Unit 2 Tail End SCR System 101.6 MMBtu/hr

Estimated Natural Gas Consumption for Urea to Ammonia Conversion:
> Unit 1 SCR System 4.3 MMBtu/hr
> Unit 2 SCR System 6.7 MMBtu/hr

The NDDH technical lead person wanted to know if Unit 2's low dust gas for reheat was correct, as it appears to be much closer to the natural gas consumption for tail end than when comparing Unit 1's LD to TESCR natural gas numbers. We told him we also noticed this difference in proportion but didn't know what numbers may be in need of revision.

We ask that you review the preliminary process design numbers for reheat fuel (and Ultra system fuel) in all four SCR cases by January 7th, so we can respond back to the NDDH on this issue, as it affects the cost effectiveness analysis for these alternatives in the updated BACT studies.

Hope you are getting a change to enjoy time with your families this holiday season.

Merry Christmas.

Bob Blakley

From: Robert Johnson [mailto:RJohnson@ftek.com]
Sent: Monday, September 28, 2009 10:05 AM
To: Blakley, Robert

Cc: Volker Rummenhohl
Subject: 28Sep_PFD Revisions

Bob,
Attached are the revised PFDs.
I added a summary line to the mass balance table, and all of the flows match those on the flow diagram.
The balance around the ULTRA system for the U1 systems has been corrected.
Please let us know if we can clarify anything.
Best Regards, Bob

Robert E. Johnson
Fuel Tech, Inc
(913) 897 0727

This message contains information that may be privileged, confidential or otherwise protected from disclosure. Unless you are the intended addressee (or authorized recipient for the addressee) you may not use, copy or disclose this message or information contained in this message to anyone. If you received this message in error, please notify the sender by replying to this message and then delete it from your system without copying or disclosing it. Thank you.

<<28Sep09_MRY2TailEnd_Rev2_natgas.pdf>> <<27Sep09_BMcD for MRYS_Additional Process Data_R2.doc>> <<28Sep09_MRY1LowDust_Rev3_natgas_580F.pdf>> <<28Sep09_MRY1TailEnd_Rev4_natgas.pdf>> <<28Sep09_MRY2LowDust_Rev2_natgas_580F.pdf>>

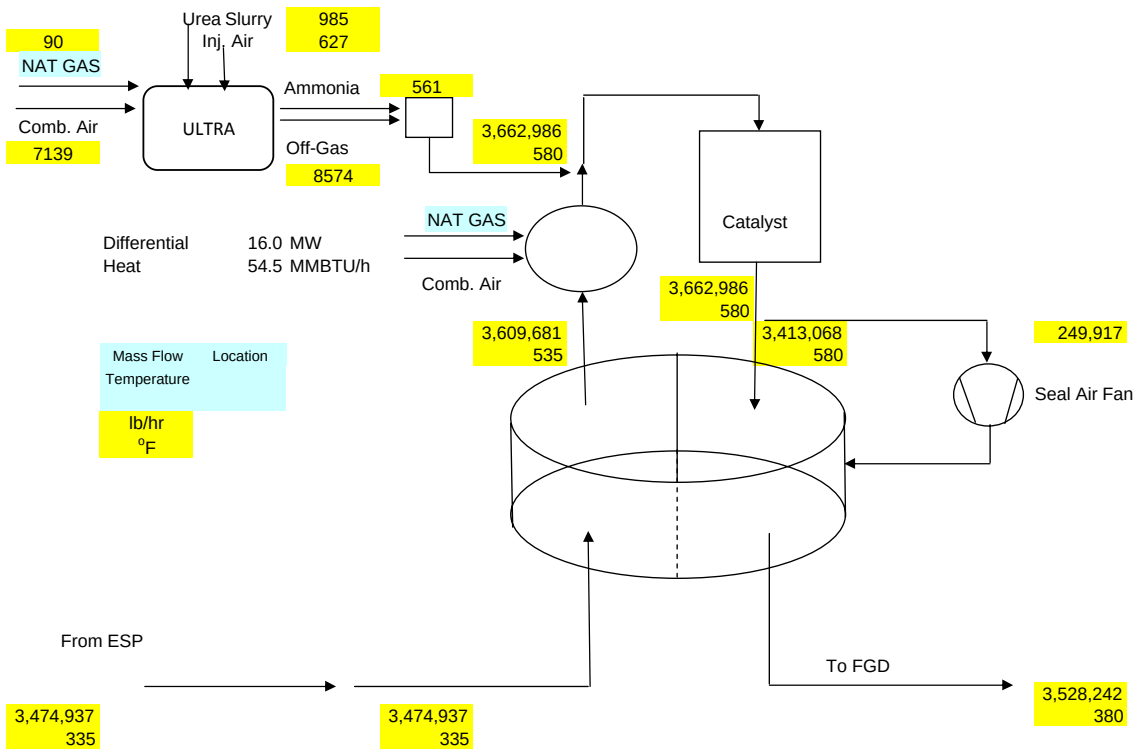
Blakley, Robert

From: Volker Rummenhohl [VRummenhohl@ftek.com]
Sent: Friday, January 22, 2010 1:46 PM
To: Blakley, Robert; Weilert, Carl
Subject: MYRS
Attachments: Jan22 2010_MRY1LowDust_Rev1_natgas_580F.pdf

Please, find attached the corrected Unit 1 Low Dust PFD.

Volker

MRY 1 Low Dust SCR Process Flow Diagram Natural Gas Fired Reheat



		ESP Outlet	GGH inlet	GGH outlet	Burner out	Catalyst Inlet	Catalyst Outlet	GGH treated inlet	FGD Inlet
Nitrogen	lb/hr	2,336,123	2,336,123	2,426,758	2,461,151	2,466,959	2,468,343	2,300,110	2,343,304
Carbon di oxide	lb/hr	614,626	614,626	638,408	643,340	643,954	643,954	600,065	615,240
Oxygen	lb/hr	205,551	205,551	213,511	214,262	215,657	215,130	200,467	205,901
Moisture	lb/hr	309,692	309,692	321,780	325,927	326,596	327,487	305,166	312,126
Sulfur di oxide	lb/hr	11,381	11,381	11,815	11,815	11,815	11,701	10,904	11,267
Sulfur tri oxide	lb/hr	0	0	7	7	7	149	139	142
Nitrogen oxide	lb/hr	0	0	0	0	0	0	0	0
Nitrogen di oxide	lb/hr	1,670	1,670	1,660	1,675	1,675	159	148	167
Argon	lb/hr	0	0	5	5	103	103	96	98
Ammonia	lb/hr	0	0	0	0	562	5	5	5
Particulate	lb/hr	70	70	73	73	73	73	0	70