Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/16 to 6/30/16

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	1/5/2016	12	7673	31.18	4.92	35.22	28.68	0.11	Bdl/JD	J	4/4	1,108.40
AURORA ENERGY LLC	1/6/2016	14	7682	32.31	4.20	34.85	28.65	0.11	JD		4	1,247.50
AURORA ENERGY LLC	1/7/2016	14	7643	32.35	3.60	35.28	28.78	0.09	JD		4	1,202.65
AURORA ENERGY LLC	1/8/2016	12	7757	31.14	4.23	36.17	28.47	0.11	JD		4	1,070.90
AURORA ENERGY LLC	1/12/2016	13	7631	32.21	4.40	35.14	28.22	0.11	Bdl/JD	J	4/4	1,200.75
AURORA ENERGY LLC	1/13/2016	18	7628	32.43	4.12	35.32	28.15	0.09	JD		4	1,613.00
AURORA ENERGY LLC	1/14/2016	14	7958	28.18	4.48	37.67	29.68	0.11	JD		4	1,188.40
AURORA ENERGY LLC	1/15/2016	16	7789	31.38	4.12	36.77	27.74	0.11	JD		4	1,385.20
AURORA ENERGY LLC	1/19/2016	18	7765	31.50	4.26	35.37	28.87	0.10	JD		4	1,604.95
AURORA ENERGY LLC	1/20/2016	16	7842	31.19	4.24	35.66	28.92	0.12	JD		4	1,439.05
AURORA ENERGY LLC	1/21/2016	15	7766	31.45	4.46	35.39	28.71	0.13	JD		4	1,348.85
AURORA ENERGY LLC	1/22/2016	22	7741	31.09	4.62	35.72	28.58	0.11	JD		4	1,962.55
AURORA ENERGY LLC	1/26/2016	14	7416	32.12	6.10	34.25	27.54	0.13	JD		4	1,350.60
AURORA ENERGY LLC	1/27/2016	12	7664	31.19	5.07	35.10	28.65	0.11	Bdl/JD	J	4/4	1,095.55
AURORA ENERGY LLC	1/28/2016	11	7741	31.54	4.52	35.16	28.79	0.10	Bdl/JD	J	4/4	982.50
AURORA ENERGY LLC	1/29/2016	13	7646	31.93	4.34	35.66	28.09	0.10	JD		4	1,140.40
AURORA ENERGY LLC	2/2/2016	12	7569	31.65	5.24	34.87	28.26	0.10	JD/Bdl	/J	4/3	1,088.10
AURORA ENERGY LLC	2/3/2016	13	7695	31.32	4.75	35.02	28.92	0.12	Bdl/JD	J	3/4	1,202.80
AURORA ENERGY LLC	2/4/2016	8	7549	30.72	6.88	34.43	27.98	0.18	Bdl/JD	J	4/4	705.70
AURORA ENERGY LLC	2/5/2016	11	7664	30.92	5.55	35.22	28.31	0.14	JD/Bdl	/J	4/4	998.75
AURORA ENERGY LLC	2/9/2016	14	7572	31.26	6.21	34.69	27.85	0.13	JD		4	1,298.35
AURORA ENERGY LLC	2/10/2016	13	7785	29.54	6.19	35.63	28.65	0.15	Bdl/JD	J	4/4	1,191.45
AURORA ENERGY LLC	2/11/2016	11	7479	31.97	5.48	34.93	27.63	0.14	Bdl/JD	J	4/4	1,023.95
AURORA ENERGY LLC	2/12/2016	15	7576	30.68	5.50	35.74	28.08	0.14	Bdl/JD	J	4/4	1,417.30
AURORA ENERGY LLC	2/16/2016	16	7634	30.60	5.38	36.09	27.93	0.14	JD/Bdl	/J	4/4	1,512.75
AURORA ENERGY LLC	2/17/2016	14	7781	29.69	5.73	35.79	28.79	0.17	Bdl/JD	J	4/4	1,299.10
AURORA ENERGY LLC	2/18/2016	11	7773	30.32	5.11	35.59	28.99	0.14	Bdl/JD	J	4/4	1,016.45
AURORA ENERGY LLC	2/19/2016	16	7808	29.51	5.45	36.18	28.86	0.14	JD/Bdl	/J	4/4	1,465.95
AURORA ENERGY LLC	2/23/2016	21	7926	29.40	4.93	36.36	29.31	0.14	JD		4	1,903.35

Rail Samples

Analysis Results for 1/1/16 to 6/30/16

AURORA ENERGY LLC	2/24/2016	16	7799	31.52	4.31	35.32	28.85	0.12	Bdl/JD	J	4/4	1,498.15
AURORA ENERGY LLC	2/25/2016	15	7794	31.50	4.13	35.15	29.22	0.10	JD		4	1,324.05
AURORA ENERGY LLC	3/1/2016	12	7806	30.97	4.49	36.14	28.40	0.12	JD		4	1,126.55
AURORA ENERGY LLC	3/2/2016	16	7805	31.54	4.14	35.52	28.80	0.11	JD		4	1,478.45
AURORA ENERGY LLC	3/3/2016	14	7717	32.25	4.14	35.10	28.52	0.11	JD		4	1,295.50
AURORA ENERGY LLC	3/4/2016	16	7828	31.13	4.14	36.06	28.67	0.11	JD		4	1,430.90
AURORA ENERGY LLC	3/8/2016	13	7701	29.55	6.64	34.82	28.99	0.12	JD/Bdl	/J	4/3	1,224.45
AURORA ENERGY LLC	3/9/2016	13	7732	30.28	5.88	34.95	28.89	0.11	JD/Bdl	/J	4/3	1,231.45
AURORA ENERGY LLC	3/15/2016	12	7823	29.23	5.87	35.65	29.26	0.11	JD/Bdl	/J	4/3	1,121.25
AURORA ENERGY LLC	3/16/2016	13	7871	30.17	4.64	35.79	29.39	0.11	JD		4	1,143.60
AURORA ENERGY LLC	3/17/2016	13	7767	28.41	7.14	35.19	29.27	0.12	Bdl/STK	J/	3/	1,222.65
AURORA ENERGY LLC	3/18/2016	14	7766	27.74	7.62	35.37	29.27	0.12	Bdl/STK	J/	3/	1,287.65
AURORA ENERGY LLC	3/22/2016	14	7719	29.44	6.41	35.32	28.84	0.11	Bdl/JD	J/	3/4	1,317.00
AURORA ENERGY LLC	3/23/2016	18	7696	30.24	5.71	34.71	29.36	0.10	Bdl/JD	J	3/4	1,647.95
AURORA ENERGY LLC	3/24/2016	16	7574	32.11	4.93	35.45	27.52	0.10	JD		4	1,413.40
AURORA ENERGY LLC	3/29/2016	12	7716	31.99	4.16	35.71	28.14	0.11	JD		4	1,091.50
AURORA ENERGY LLC	3/30/2016	13	7642	32.31	4.18	35.81	27.70	0.11	JD		4	1,222.60
AURORA ENERGY LLC	3/31/2016	15	7741	31.85	4.24	35.23	28.68	0.11	JD		4	1,385.25
AURORA ENERGY LLC	4/1/2016	12	7723	31.82	4.28	35.95	27.95	0.11	JD		4	1,102.80
AURORA ENERGY LLC	4/5/2016	12	7666	31.80	4.77	35.48	27.95	0.12	JD		4	1,153.20
AURORA ENERGY LLC	4/6/2016	13	7705	31.70	4.66	35.12	28.53	0.12	JD		4	1,206.05
AURORA ENERGY LLC	4/7/2016	12	7602	32.54	4.49	34.80	28.18	0.12	JD		4	1,156.65
AURORA ENERGY LLC	4/8/2016	13	7766	31.23	4.49	36.04	28.25	0.11	JD		4	1,227.00
AURORA ENERGY LLC	4/12/2016	10	7756	31.50	4.66	35.46	28.39	0.12	JD		4	960.30
AURORA ENERGY LLC	4/13/2016	11	7760	31.37	4.62	35.61	28.41	0.12	JD		4	1,069.45
AURORA ENERGY LLC	4/14/2016	9	7733	31.94	4.36	35.32	28.38	0.11	JD		4	854.95
AURORA ENERGY LLC	4/15/2016	9	7768	30.79	4.70	35.74	28.78	0.11	JD		4	839.70
AURORA ENERGY LLC	4/18/2016	12	7810	31.46	4.40	35.85	28.29	0.11	JD		4	1,126.80
AURORA ENERGY LLC	4/19/2016	11	7621	32.18	4.88	34.90	28.05	0.11	JD		4	1,035.05
AURORA ENERGY LLC	4/20/2016	13	7585	32.41	4.90	34.42	28.27	0.10	JD		4	1,274.85

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/16 to 6/30/16

AURORA ENERGY LLC	4/21/2016	12	7648	31.78	4.97	34.64	28.61	0.10	JD		4	1,128.20
AURORA ENERGY LLC	4/25/2016	12	7804	30.65	5.06	35.23	29.07	0.11	JD		4	1,120.80
AURORA ENERGY LLC	4/26/2016	10	7794	30.80	4.83	35.24	29.13	0.10	JD		4	1,017.70
AURORA ENERGY LLC	4/27/2016	13	7792	31.50	4.34	35.33	28.84	0.10	JD		4	1,255.45
AURORA ENERGY LLC	4/28/2016	13	7717	31.14	4.83	35.23	28.80	0.11	JD		4	1,284.75
AURORA ENERGY LLC	5/2/2016	12	7733	31.54	4.44	35.22	28.81	0.10	JD		4	1,168.35
AURORA ENERGY LLC	5/3/2016	12	7747	31.52	4.43	35.40	28.66	0.11	JD		4	1,073.35
AURORA ENERGY LLC	5/9/2016	3	7772	30.90	5.16	34.88	29.06	0.13	JD		4	288.15
AURORA ENERGY LLC	5/10/2016	3	7870	29.71	5.13	36.25	28.91	0.12	JD		4	268.35
AURORA ENERGY LLC	5/11/2016	4	7720	33.22	3.17	34.91	28.70	0.08	JD		4	372.65
AURORA ENERGY LLC	5/13/2016	8	7504	33.43	4.57	34.09	27.91	0.10	JD		4	761.40
AURORA ENERGY LLC	5/17/2016	11	7630	32.79	4.33	34.71	28.17	0.10	JD		4	1,084.05
AURORA ENERGY LLC	5/18/2016	11	7466	34.38	4.30	33.98	27.35	0.10	JD/JD		3/4	1,050.25
AURORA ENERGY LLC	5/19/2016	11	7277	32.62	7.83	33.49	26.07	0.13	JD/JD		3/4	1,127.45
AURORA ENERGY LLC	5/20/2016	12	7552	31.48	6.32	34.89	27.32	0.12	JD/JD		3/4	1,176.40
AURORA ENERGY LLC	5/23/2016	14	7661	31.33	5.63	34.90	28.15	0.12	JD/JD		3/4	1,367.20
AURORA ENERGY LLC	5/24/2016	13	7685	31.62	5.34	35.25	27.80	0.12	JD/JD		3/4	1,229.45
AURORA ENERGY LLC	5/25/2016	13	7492	32.88	5.31	34.79	27.03	0.12	JD/JD		3/4	1,237.80
AURORA ENERGY LLC	5/26/2016	10	7627	31.34	5.59	35.37	27.71	0.13	JD/JD		3/4	996.95
AURORA ENERGY LLC	5/31/2016	13	7730	30.85	5.28	36.10	27.77	0.11	JD		4	1,246.35
AURORA ENERGY LLC	6/1/2016	13	7826	30.81	4.68	36.26	28.26	0.10	JD/JD		4/3	1,188.90
AURORA ENERGY LLC	6/2/2016	12	7791	31.02	4.90	35.82	28.26	0.12	JD/JD		3/4	1,073.70
AURORA ENERGY LLC	6/3/2016	14	7647	28.04	8.54	35.38	28.04	0.21	JD/Bdl	/K	3/4	1,360.65
AURORA ENERGY LLC	6/6/2016	13	7411	30.10	8.84	34.34	26.72	0.23	Bdl/JD	K	4/3	1,274.75
AURORA ENERGY LLC	6/7/2016	11	7464	31.52	6.83	34.18	27.47	0.11	Bdl/JD	K	4/3	1,035.45
AURORA ENERGY LLC	6/8/2016	11	7491	30.78	7.37	34.34	27.51	0.14	Bdl/JD	K	4/3	1,040.50
AURORA ENERGY LLC	6/9/2016	10	7613	30.80	6.31	35.15	27.74	0.13	Bdl/JD	K	4/3	993.00
AURORA ENERGY LLC	6/13/2016	12	7632	31.54	5.50	34.94	28.02	0.12	Bdl/JD		4/3	1,190.00
AURORA ENERGY LLC	6/14/2016	12	7599	31.45	5.87	34.93	27.76	0.12	JD/JD		3/4	1,177.30
AURORA ENERGY LLC	6/16/2016	24	7514	32.67	5.39	35.16	26.78	0.12	JD/JD		3/4	2,323.85

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/16 to 6/30/16

AURORA ENERGY LLC	6/20/2016	16	7606	31.88	5.51	35.05	27.57	0.10	JD/JD		3/4	1,578.60
AURORA ENERGY LLC	6/21/2016	16	7641	31.29	6.01	34.95	27.75	0.12	JD/JD		3/4	1,540.35
AURORA ENERGY LLC	6/23/2016	15	7667	31.90	5.11	34.65	28.35	0.12	JD/JD		3/4	1,438.65
AURORA ENERGY LLC	6/27/2016	12	7480	31.07	6.90	34.53	27.50	0.11	JD/JD		3/4	1,109.05
AURORA ENERGY LLC	6/28/2016	11	7637	31.39	5.94	35.68	27.00	0.12	JD/JD		3/4	1,037.70
AURORA ENERGY LLC	6/29/2016	9	7577	30.69	7.06	35.22	27.03	0.13	JD/JD		3/4	863.15
AURORA ENERGY LLC	6/30/2016	13	7574	31.03	6.80	35.12	27.06	0.13	JD/JD		3/4	1,267.15

Customer Weighted Average

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	115282.20	7683.00	31.21	5.22	35.30	28.29	0.12

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
EIELSON AFB - DFAS	1/5/2016	9	7520	31.96	5.18	34.80	28.07	0.12	Bdl/JD	J	4/4	840.80
EIELSON AFB - DFAS	1/6/2016	10	7660	32.32	4.25	34.80	28.64	0.11	JD		4	916.40
EIELSON AFB - DFAS	1/7/2016	10	7724	32.29	3.66	35.34	28.72	0.10	JD		4	908.10
EIELSON AFB - DFAS	1/12/2016	10	7633	32.22	4.49	35.25	28.05	0.12	Bdl/JD	J	4/4	927.90
EIELSON AFB - DFAS	1/13/2016	10	7661	32.66	3.66	35.37	28.32	0.08	JD		4	893.05
EIELSON AFB - DFAS	1/14/2016	10	7709	31.71	4.17	35.75	28.37	0.10	JD		4	888.45
EIELSON AFB - DFAS	1/15/2016	10	7778	31.00	4.60	36.33	28.08	0.12	JD		4	909.15
EIELSON AFB - DFAS	1/19/2016	12	7712	31.80	4.38	35.14	28.68	0.10	JD		4	1,071.20
EIELSON AFB - DFAS	1/20/2016	11	7723	32.23	4.18	35.17	28.42	0.12	JD		4	973.20
EIELSON AFB - DFAS	1/21/2016	15	7638	32.53	4.44	34.87	28.17	0.13	JD		4	1,379.00
EIELSON AFB - DFAS	1/22/2016	12	7624	31.93	4.92	35.16	28.00	0.11	JD		4	1,105.20
EIELSON AFB - DFAS	1/26/2016	12	7490	32.32	5.40	34.27	28.01	0.11	JD		4	1,134.75
EIELSON AFB - DFAS	1/27/2016	13	7533	31.49	5.77	34.90	27.85	0.12	Bdl/JD	J	4/4	1,215.95
EIELSON AFB - DFAS	1/28/2016	15	7573	32.67	4.75	34.63	27.96	0.10	Bdl/JD	J	4/4	1,350.75
EIELSON AFB - DFAS	2/2/2016	12	7557	32.09	4.95	35.17	27.80	0.10	JD/Bdl	/J	4/3	1,112.15
EIELSON AFB - DFAS	2/3/2016	12	7717	31.10	5.07	34.90	28.93	0.14	Bdl/JD	J	3/4	1,124.55
EIELSON AFB - DFAS	2/4/2016	13	7624	30.85	5.97	34.68	28.51	0.17	Bdl/JD	J	4/4	1,191.10
EIELSON AFB - DFAS	2/5/2016	12	7616	31.11	5.83	35.41	27.65	0.13	JD/Bdl	/J	4/4	1,132.75

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/16 to 6/30/16

Customer Weighted Average

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
UNIVERSITY OF ALASKA	31802.70	7662.00	31.27	5.37	35.30	28.06	0.12

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	115282.20	7683.00	31.21	5.22	35.30	28.29	0.12
EIELSON AFB - DFAS	80214.85	7611.00	31.53	5.47	34.99	28.02	0.12
FORT WAINWRIGHT ACCOUNTING	126389.60	7620.00	31.49	5.41	35.01	28.08	0.12
OTHER COAL SALES	70008.05	7699.00	29.94	6.15	35.52	28.38	0.13
UNIVERSITY OF ALASKA	31802.70	7662.00	31.27	5.37	35.30	28.06	0.12
Total	423697.4	7651.59	31.15	5.49	35.19	28.17	0.12

**This analysis is representative of the coal shipped.
The sulfur content in this shipment was analyzed
using sulfur standard ASTM D4239.
Coleen Thompson Date** 7-18-16

Coleen Thompson

Signature

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/16 to 12/31/16

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	7/5/2016	15	7570	30.93	6.78	34.59	27.71	0.13	JD/JD		3/4	1,417.10
AURORA ENERGY LLC	7/6/2016	10	7661	30.50	6.07	35.20	28.23	0.11	JD/JD		3/4	999.55
AURORA ENERGY LLC	7/8/2016	15	7588	31.27	6.06	35.54	27.13	0.11	JD/JD		3/4	1,368.70
AURORA ENERGY LLC	7/11/2016	19	7496	32.08	6.04	34.43	27.45	0.11	JD/JD		3/4	1,782.30
AURORA ENERGY LLC	7/12/2016	14	7507	30.39	7.57	35.14	26.90	0.16	Bdl/JD	K	4/3	1,387.10
AURORA ENERGY LLC	7/14/2016	18	7561	29.88	7.43	35.07	27.62	0.16	Bdl/JD	K/	4/3	1,766.80
AURORA ENERGY LLC	7/18/2016	17	7711	29.16	7.11	35.83	27.90	0.17	JD/Bdl	/K	3/4	1,594.70
AURORA ENERGY LLC	7/19/2016	15	7689	29.26	6.72	35.46	28.56	0.17	Bdl/JD	K	4/3	1,378.10
AURORA ENERGY LLC	7/21/2016	18	7652	29.41	6.98	35.14	28.47	0.17	Bdl/JD	K	4/3	1,724.10
AURORA ENERGY LLC	7/25/2016	12	7689	29.04	7.41	34.83	28.73	0.17	Bdl/JD	K	4/3	1,116.65
AURORA ENERGY LLC	7/26/2016	11	7590	29.91	7.20	34.97	27.92	0.16	Bdl/JD	K	4/3	1,036.20
AURORA ENERGY LLC	7/28/2016	11	7616	29.35	7.50	35.18	27.97	0.18	Bdl/JD	K	4/3	1,042.70
AURORA ENERGY LLC	8/1/2016	14	7596	29.24	8.06	34.84	27.87	0.15	Bdl/JD	K	4/3	1,351.50
AURORA ENERGY LLC	8/2/2016	14	7456	30.31	8.00	34.62	27.08	0.15	Bdl/JD	K/	4/3	1,371.25
AURORA ENERGY LLC	8/4/2016	13	7543	30.45	7.11	34.97	27.47	0.14	Bdl/JD	K	4/3	1,234.55
AURORA ENERGY LLC	8/8/2016	19	7554	29.57	8.13	34.64	27.67	0.15	Bdl/JD	K	4/3	1,829.20
AURORA ENERGY LLC	8/9/2016	17	7555	29.32	8.20	34.99	27.50	0.16	Bdl/JD	K/	4/3	1,727.15
AURORA ENERGY LLC	8/12/2016	17	7518	28.78	8.93	35.37	26.93	0.22	JD/Bdl	/K	3/4	1,641.20
AURORA ENERGY LLC	8/15/2016	17	7662	28.43	8.18	35.09	28.30	0.21	Bdl/JD	K	4/3	1,541.00
AURORA ENERGY LLC	8/16/2016	17	7663	29.02	7.89	35.79	27.31	0.18	Bdl/JD	K	4/3	1,617.55
AURORA ENERGY LLC	8/18/2016	16	7544	29.54	7.80	35.74	26.92	0.17	Bdl/JD	K	4/3	1,515.30
AURORA ENERGY LLC	8/23/2016	19	7487	29.32	8.70	36.15	25.83	0.18	Bdl/JD	K	4/3	1,860.65
AURORA ENERGY LLC	8/24/2016	19	7632	29.26	7.19	36.57	26.99	0.16	Bdl/JD	K	4/3	1,808.85
AURORA ENERGY LLC	8/25/2016	18	7590	31.48	5.63	35.08	27.81	0.13	JD/JD		4/3	1,682.30
AURORA ENERGY LLC	8/29/2016	19	7289	30.74	9.14	34.44	25.70	0.22	JD/JD		4/3	1,838.20
AURORA ENERGY LLC	8/30/2016	18	7582	30.55	6.91	35.46	27.09	0.15	JD/JD		3/4	1,697.80
AURORA ENERGY LLC	9/2/2016	26	7500	30.40	7.65	35.22	26.74	0.14	JD/JD		3/4	2,510.75
AURORA ENERGY LLC	9/6/2016	18	7450	32.43	6.09	34.66	26.83	0.12	JD/JD		4/3	1,694.70
AURORA ENERGY LLC	9/7/2016	17	7524	31.76	5.90	35.65	26.70	0.12	JD/Bdl	/K	3/4	1,605.50
AURORA ENERGY LLC	9/8/2016	10	7550	30.91	6.94	34.82	27.35	0.13	JD/Bdl	/K	4/4	953.55

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/16 to 12/31/16

AURORA ENERGY LLC	9/9/2016	10	7573	30.37	6.68	35.37	27.58	0.12	Bdl/JD	K	4/3	959.50
AURORA ENERGY LLC	9/27/2016	7	7558	29.53	7.77	36.09	26.62	0.14	JD/JD		3/4	660.95
AURORA ENERGY LLC	9/30/2016	18	7663	29.00	7.19	36.55	27.26	0.12	JD/Bdl	/K	3/4	1,783.60
AURORA ENERGY LLC	10/3/2016	24	7551	30.59	7.00	35.86	26.56	0.11	JD/Bdl	/K	3/4	2,244.55
AURORA ENERGY LLC	10/5/2016	28	7514	30.13	7.52	34.79	27.56	0.12	Bdl/JD	K	4/3	2,682.10
AURORA ENERGY LLC	10/10/2016	20	7615	29.98	6.97	35.09	27.97	0.12	Bdl/JD	K	4/3	1,895.45
AURORA ENERGY LLC	10/11/2016	21	7415	29.36	9.27	34.88	26.50	0.12	JD		4	1,974.25
AURORA ENERGY LLC	10/17/2016	14	7725	30.51	5.80	35.47	28.22	0.11	JD		4	1,327.05
AURORA ENERGY LLC	10/18/2016	10	7666	30.86	5.74	35.75	27.65	0.11	JD/JD		3/4	910.90
AURORA ENERGY LLC	10/19/2016	11	7674	30.61	5.79	35.44	28.17	0.10	JD/JD		3/4	940.90
AURORA ENERGY LLC	10/24/2016	12	7760	29.11	6.56	36.37	27.97	0.12	JD/JD		3/4	1,137.45
AURORA ENERGY LLC	10/25/2016	12	7729	29.22	6.51	36.28	27.99	0.12	Bdl		6	1,063.15
AURORA ENERGY LLC	10/26/2016	14	7708	28.38	7.47	36.44	27.71	0.12	Bdl/JD		6/4	1,171.40
AURORA ENERGY LLC	10/27/2016	14	7765	27.43	7.69	37.53	27.36	0.13	Bdl/JD		6/4	1,243.80
AURORA ENERGY LLC	10/31/2016	14	7742	26.38	8.92	37.76	26.94	0.14	Bdl		6	1,220.95
AURORA ENERGY LLC	11/1/2016	15	7705	26.55	9.09	38.27	26.09	0.14	Bdl		6	1,290.10
AURORA ENERGY LLC	11/2/2016	14	7726	26.53	8.80	37.76	26.91	0.14	Bdl		6	1,238.05
AURORA ENERGY LLC	11/3/2016	13	7774	26.33	8.55	37.90	27.23	0.14	Bdl		6	1,100.70
AURORA ENERGY LLC	11/7/2016	15	7680	27.17	8.92	37.45	26.47	0.13	Bdl		6	1,346.80
AURORA ENERGY LLC	11/8/2016	15	7646	26.81	9.38	37.93	25.89	0.14	Bdl		6	1,315.35
AURORA ENERGY LLC	11/9/2016	15	7631	27.00	9.17	37.46	26.37	0.14	Bdl		6	1,316.60
AURORA ENERGY LLC	11/10/2016	16	7714	26.75	8.56	37.61	27.09	0.13	Bdl		6	1,394.90
AURORA ENERGY LLC	11/14/2016	16	7658	26.44	9.11	37.77	26.68	0.14	Bdl		6	1,432.15
AURORA ENERGY LLC	11/16/2016	16	7680	27.17	8.40	37.84	26.60	0.14	Bdl		6	1,436.00
AURORA ENERGY LLC	11/17/2016	15	7748	27.26	7.86	37.64	27.24	0.13	Bdl		6	1,320.90
AURORA ENERGY LLC	11/21/2016	16	7710	27.01	8.43	37.84	26.73	0.13	Bdl		6	1,456.15
AURORA ENERGY LLC	11/22/2016	19	7751	27.30	8.01	38.35	26.34	0.13	Bdl		6	1,754.65
AURORA ENERGY LLC	11/23/2016	17	7736	27.32	7.92	38.15	26.61	0.13	Bdl		6	1,432.75
AURORA ENERGY LLC	11/28/2016	10	7705	27.45	7.89	37.39	27.28	0.13	Bdl		6	876.20
AURORA ENERGY LLC	11/29/2016	10	7464	27.88	9.89	36.20	26.04	0.13	Bdl		6	923.55
AURORA ENERGY LLC	11/30/2016	10	7586	29.83	6.92	36.51	26.75	0.13	JD		4	881.80
AURORA ENERGY LLC	12/1/2016	11	6899	28.06	14.52	32.87	24.55	0.12	Bdl/JD		6/4	913.05

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/16 to 12/31/16

AURORA ENERGY LLC	12/5/2016	12	7660	30.15	6.54	35.11	28.21	0.15	JD	4	1,048.05
AURORA ENERGY LLC	12/6/2016	12	7635	29.90	6.82	35.74	27.54	0.14	JD	4	1,034.60
AURORA ENERGY LLC	12/7/2016	11	7691	30.39	5.66	35.64	28.32	0.12	Bdl/JD	6/4	934.95
AURORA ENERGY LLC	12/8/2016	12	7684	29.22	7.21	37.06	26.52	0.12	JD	4	1,028.90
AURORA ENERGY LLC	12/12/2016	15	7734	28.36	7.03	36.54	28.08	0.16	JD	4	1,336.05
AURORA ENERGY LLC	12/13/2016	15	7656	27.80	8.19	37.25	26.77	0.14	JD	4	1,297.80
AURORA ENERGY LLC	12/14/2016	15	7683	27.72	7.99	36.90	27.40	0.14	JD	4	1,347.60
AURORA ENERGY LLC	12/15/2016	8	7679	27.93	7.85	36.68	27.55	0.15	JD/Bdl	4/6	735.90
AURORA ENERGY LLC	12/19/2016	18	7626	27.91	8.63	37.07	26.40	0.14	Bdl/JD	6/4	1,625.50
AURORA ENERGY LLC	12/20/2016	23	7529	28.73	8.36	36.18	26.74	0.13	Bdl	6	2,003.15
AURORA ENERGY LLC	12/21/2016	8	7177	33.28	5.98	34.15	26.60	0.11	JD	4	702.25
AURORA ENERGY LLC	12/22/2016	7	7498	30.41	6.92	35.74	26.93	0.13	JD	4	625.90
AURORA ENERGY LLC	12/27/2016	13	7617	30.42	6.60	35.98	27.01	0.12	JD	4	1,202.80
AURORA ENERGY LLC	12/28/2016	13	7774	30.23	5.76	36.52	27.49	0.13	JD/Bdl	4/6	1,132.75
AURORA ENERGY LLC	12/29/2016	14	7656	30.08	6.37	36.50	27.06	0.13	Bdl/JD	6/4	1,242.95
AURORA ENERGY LLC	12/29/2016	4	7427	30.47	7.75	35.36	26.42	0.13	Bdl/JD	6/4	355.05
AURORA ENERGY LLC	12/31/2016	14	7668	27.72	8.27	37.22	26.79	0.14	Bdl/JD	6/4	1,292.45

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	107687.35	7604.00	29.23	7.61	35.99	27.17	0.14

This analysis is representative of the coal shipped.
The sulfur content in this shipment was analyzed using sulfur standard ASTM D4239.
Coleen Thompson Date 1-11-17

Coleen Thompson
Signature

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/17 to 6/30/17

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	1/3/2017	18	7477	30.01	7.72	36.14	26.13	0.14	JD		4	1,692.15
AURORA ENERGY LLC	1/4/2017	19	7629	29.79	6.61	35.98	27.62	0.14	JD		4	1,625.15
AURORA ENERGY LLC	1/5/2017	19	7546	29.25	7.60	35.83	27.32	0.16	JD/STK		4/L	1,722.00
AURORA ENERGY LLC	1/6/2017	19	7556	32.13	5.19	35.58	27.11	0.12	JD		4	1,667.00
AURORA ENERGY LLC	1/10/2017	16	7711	31.53	4.83	35.98	27.66	0.11	JD		4	1,414.60
AURORA ENERGY LLC	1/11/2017	11	7587	32.46	4.80	35.38	27.37	0.12	JD		4	960.60
AURORA ENERGY LLC	1/12/2017	15	7557	32.36	5.01	35.04	27.60	0.12	JD		4	1,360.55
AURORA ENERGY LLC	1/13/2017	10	7657	31.58	5.05	35.99	27.38	0.15	JD		4	911.65
AURORA ENERGY LLC	1/16/2017	11	7484	33.02	5.28	34.59	27.11	0.13	JD		4	953.00
AURORA ENERGY LLC	1/17/2017	7	7796	31.16	4.49	35.71	28.65	0.11	JD		4	560.65
AURORA ENERGY LLC	1/19/2017	8	7453	32.25	5.64	35.11	27.00	0.13	JD		4	622.05
AURORA ENERGY LLC	1/20/2017	7	7517	33.70	4.45	34.77	27.08	0.11	JD		4	636.35
AURORA ENERGY LLC	1/21/2017	14	7599	33.03	4.28	34.94	27.75	0.10	JD		4	1,222.40
AURORA ENERGY LLC	1/23/2017	11	7669	32.37	4.38	35.00	28.26	0.10	JD		4	970.45
AURORA ENERGY LLC	1/24/2017	11	7726	32.24	4.34	35.68	27.75	0.10	JD		4	941.95
AURORA ENERGY LLC	1/25/2017	11	7644	32.08	4.71	35.28	27.94	0.09	JD		4	974.55
AURORA ENERGY LLC	1/26/2017	8	7572	32.05	5.46	34.92	27.57	0.10	JD		4	718.10
AURORA ENERGY LLC	1/27/2017	11	7639	31.03	5.90	36.14	26.94	0.12	JD		4	981.45
AURORA ENERGY LLC	1/30/2017	11	7572	32.29	5.53	35.74	26.45	0.12	JD		4	953.15
AURORA ENERGY LLC	1/31/2017	11	7217	32.88	6.93	34.88	25.31	0.14	JD		4	975.95
AURORA ENERGY LLC	2/1/2017	24	6822	34.48	8.09	32.84	24.60	0.14	JD		4	2,255.10
AURORA ENERGY LLC	2/1/2017	4	7170	33.55	6.67	33.62	26.17	0.13	JD		4	355.30
AURORA ENERGY LLC	2/1/2017	3	7252	33.71	5.99	33.75	26.56	0.13	JD		4	267.25
AURORA ENERGY LLC	2/6/2017	9	7551	32.85	4.86	34.74	27.55	0.12	JD		4	790.05
AURORA ENERGY LLC	2/7/2017	10	7554	33.29	4.68	34.92	27.12	0.11	JD		4	877.60
AURORA ENERGY LLC	2/8/2017	10	7691	32.19	4.46	35.15	28.22	0.11	JD		4	869.65
AURORA ENERGY LLC	2/9/2017	9	7651	32.24	4.61	35.16	28.01	0.12	JD		4	796.00
AURORA ENERGY LLC	2/10/2017	10	7729	31.63	4.62	35.76	28.00	0.11	JD		4	875.35
AURORA ENERGY LLC	2/13/2017	9	7625	32.37	4.69	35.17	27.77	0.13	JD		4	790.10
AURORA ENERGY LLC	2/14/2017	8	7567	32.56	4.97	35.16	27.32	0.11	JD		4	692.50

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/17 to 6/30/17

AURORA ENERGY LLC	2/15/2017	10	7634	32.54	4.49	35.36	27.61	0.11	JD	4	869.00
AURORA ENERGY LLC	2/16/2017	8	7498	33.04	4.98	35.17	26.82	0.12	JD	4	717.70
AURORA ENERGY LLC	2/17/2017	9	7463	33.10	5.10	34.31	27.50	0.12	JD	4	814.60
AURORA ENERGY LLC	2/21/2017	8	7588	32.49	4.85	35.18	27.48	0.12	JD	4	701.75
AURORA ENERGY LLC	2/22/2017	11	7557	33.17	4.44	34.73	27.66	0.11	JD	4	980.00
AURORA ENERGY LLC	2/23/2017	12	7563	32.96	4.14	35.22	27.69	0.10	JD	4	1,045.50
AURORA ENERGY LLC	2/24/2017	12	7688	32.39	4.22	35.42	27.98	0.11	JD	4	957.20
AURORA ENERGY LLC	2/27/2017	14	7690	32.22	4.51	35.99	27.28	0.11	JD	4	1,176.20
AURORA ENERGY LLC	3/1/2017	13	7165	33.78	5.52	34.38	26.32	0.11	JD	4	1,197.25
AURORA ENERGY LLC	3/2/2017	12	7074	33.61	5.95	34.70	25.75	0.11	JD	4	1,089.10
AURORA ENERGY LLC	3/3/2017	17	7451	31.82	5.88	35.09	27.21	0.11	JD	4	1,454.95
AURORA ENERGY LLC	3/6/2017	26	7216	32.35	6.16	35.29	26.19	0.11	JD	4	2,389.10
AURORA ENERGY LLC	3/8/2017	13	7505	31.11	6.36	35.34	27.20	0.12	JD/Bdl	4/6	1,072.30
AURORA ENERGY LLC	3/11/2017	28	7281	33.37	5.39	35.01	26.24	0.12	JD/Bdl	4/6	2,582.40
AURORA ENERGY LLC	3/11/2017	12	7569	32.00	4.79	36.18	27.04	0.10	JD/Bdl	4/6	1,076.05
AURORA ENERGY LLC	3/14/2017	13	7651	31.55	4.89	35.87	27.69	0.11	JD	4	1,119.25
AURORA ENERGY LLC	3/15/2017	15	7583	31.90	5.01	35.77	27.32	0.12	JD	4	1,321.40
AURORA ENERGY LLC	3/20/2017	13	7524	32.29	4.83	35.84	27.04	0.12	JD	4	1,120.40
AURORA ENERGY LLC	3/21/2017	12	7579	32.14	4.66	35.78	27.42	0.12	JD	4	1,035.50
AURORA ENERGY LLC	3/22/2017	12	7667	32.19	4.11	35.51	28.20	0.11	JD	4	1,045.35
AURORA ENERGY LLC	3/23/2017	14	7595	31.37	5.88	34.77	27.97	0.13	JD/GRP	4/C	1,240.20
AURORA ENERGY LLC	3/27/2017	14	7651	31.46	5.35	35.39	27.81	0.13	JD/GRP	4/C	1,246.80
AURORA ENERGY LLC	3/28/2017	14	7626	31.21	5.57	34.76	28.47	0.13	JD/GRP	4/M	1,254.00
AURORA ENERGY LLC	3/29/2017	10	7571	31.75	5.59	34.86	27.81	0.13	JD/GRP	4/M	902.05
AURORA ENERGY LLC	3/30/2017	13	7577	31.50	5.45	35.40	27.65	0.12	JD/GRP	4/M	1,119.90
AURORA ENERGY LLC	4/3/2017	13	7646	31.95	4.45	36.24	27.36	0.11	JD	4	1,123.15
AURORA ENERGY LLC	4/4/2017	13	7653	32.13	4.28	36.07	27.52	0.10	JD	4	1,148.05
AURORA ENERGY LLC	4/5/2017	13	7681	31.32	5.21	35.50	27.97	0.13	JD/GRP	4/C	1,164.90
AURORA ENERGY LLC	4/6/2017	8	7615	32.59	4.35	35.95	27.12	0.10	JD	4	726.65
AURORA ENERGY LLC	4/10/2017	11	7682	32.21	4.28	37.03	26.49	0.11	JD	4	977.45
AURORA ENERGY LLC	4/11/2017	12	7681	31.95	4.39	35.97	27.69	0.10	JD	4	1,085.65
AURORA ENERGY LLC	4/12/2017	7	7552	33.01	4.28	35.11	27.60	0.11	JD	4	674.75

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/17 to 6/30/17

AURORA ENERGY LLC	4/13/2017	11	7385	34.02	4.57	34.56	26.86	0.10	JD	4	1,018.95
AURORA ENERGY LLC	4/18/2017	15	7644	32.05	4.35	36.70	26.91	0.11	JD	4	1,391.00
AURORA ENERGY LLC	4/19/2017	7	7663	31.22	5.39	35.74	27.64	0.13	JD	4	624.95
AURORA ENERGY LLC	4/20/2017	15	7624	32.50	4.35	35.84	27.31	0.11	JD	4	1,314.50
AURORA ENERGY LLC	4/21/2017	17	7590	31.89	4.70	35.91	27.50	0.11	JD	4	1,591.90
AURORA ENERGY LLC	4/24/2017	15	7675	31.63	4.45	36.49	27.44	0.10	JD	4	1,391.90
AURORA ENERGY LLC	4/25/2017	13	7577	33.14	4.06	35.38	27.44	0.11	JD	4	1,272.55
AURORA ENERGY LLC	4/26/2017	9	7592	33.84	3.51	35.03	27.62	0.10	JD	4	894.20
AURORA ENERGY LLC	4/27/2017	8	7621	32.87	3.81	36.16	27.16	0.10	JD	4	775.45
AURORA ENERGY LLC	5/1/2017	7	7734	31.63	4.44	36.23	27.71	0.12	JD	4	645.70
AURORA ENERGY LLC	5/2/2017	6	7739	30.89	4.60	36.41	28.10	0.11	JD	4	563.10
AURORA ENERGY LLC	5/3/2017	4	7825	30.98	4.22	36.19	28.62	0.11	JD	4	371.55
AURORA ENERGY LLC	5/8/2017	4	7461	33.26	4.78	35.09	26.88	0.12	JD	4	381.75
AURORA ENERGY LLC	5/9/2017	6	7489	32.64	5.06	34.89	27.42	0.11	JD	4	517.50
AURORA ENERGY LLC	5/11/2017	4	7538	31.86	5.27	35.86	27.02	0.11	JD	4	359.75
AURORA ENERGY LLC	5/15/2017	9	7599	31.85	4.95	36.29	26.91	0.10	JD	4	807.40
AURORA ENERGY LLC	5/16/2017	8	7633	31.97	4.66	36.40	26.98	0.10	JD	4	739.40
AURORA ENERGY LLC	5/17/2017	5	7574	33.83	4.08	34.88	27.20	0.09	JD	4	466.55
AURORA ENERGY LLC	5/18/2017	4	7650	33.31	3.42	35.81	27.47	0.09	JD	4	354.65
AURORA ENERGY LLC	5/19/2017	7	7656	32.09	4.24	35.89	27.79	0.10	JD	4	603.30
AURORA ENERGY LLC	5/22/2017	16	7756	31.40	4.24	36.49	27.87	0.10	JD	4	1,430.45
AURORA ENERGY LLC	5/23/2017	12	7512	33.57	4.17	35.75	26.51	0.13	JD	4	1,090.40
AURORA ENERGY LLC	5/24/2017	12	7669	32.70	3.95	35.99	27.36	0.12	JD	4	1,097.30
AURORA ENERGY LLC	5/26/2017	14	7657	31.91	4.59	36.48	27.02	0.11	JD	4	1,311.30
AURORA ENERGY LLC	5/30/2017	9	7675	31.80	4.72	36.29	27.19	0.11	JD	4	835.35
AURORA ENERGY LLC	5/31/2017	8	7693	31.83	4.71	36.93	26.53	0.11	JD	4	747.65
AURORA ENERGY LLC	6/1/2017	3	7701	31.47	4.41	37.05	27.07	0.10	JD	4	265.40
AURORA ENERGY LLC	6/2/2017	4	7777	31.10	4.13	36.64	28.13	0.10	JD	4	346.30
AURORA ENERGY LLC	6/5/2017	12	7650	32.12	4.55	35.36	27.98	0.10	JD	4	1,061.75
AURORA ENERGY LLC	6/6/2017	13	7594	32.33	4.47	35.40	27.81	0.11	JD	4	1,165.40
AURORA ENERGY LLC	6/8/2017	12	7636	32.08	4.40	35.99	27.53	0.10	JD	4	1,067.80
AURORA ENERGY LLC	6/9/2017	11	7674	31.80	4.30	36.21	27.70	0.11	JD	4	1,011.25

Usibelli Coal Mine

Rail Samples

Analysis Results for 1/1/17 to 6/30/17

AURORA ENERGY LLC	6/12/2017	12	7609	32.30	4.32	36.00	27.38	0.10	JD	4	1,063.85
AURORA ENERGY LLC	6/13/2017	13	7682	31.87	4.25	36.35	27.54	0.09	JD	4	1,140.90
AURORA ENERGY LLC	6/15/2017	12	7675	31.97	4.75	36.23	27.06	0.12	JD	4	1,093.80
AURORA ENERGY LLC	6/16/2017	13	7665	32.28	4.53	35.98	27.21	0.12	JD	4	1,167.30
AURORA ENERGY LLC	6/19/2017	11	7699	32.34	3.91	36.45	27.31	0.10	JD	4	982.95
AURORA ENERGY LLC	6/20/2017	12	7714	32.35	4.07	35.98	27.60	0.10	JD	4	1,115.05
AURORA ENERGY LLC	6/22/2017	12	7555	33.32	4.39	35.52	26.77	0.12	JD	4	1,083.45
AURORA ENERGY LLC	6/23/2017	13	7642	32.79	4.37	35.68	27.17	0.12	JD	4	1,163.90
AURORA ENERGY LLC	6/26/2017	8	7699	32.23	4.30	35.95	27.52	0.12	JD	4	701.50
AURORA ENERGY LLC	6/27/2017	8	7754	31.81	4.08	36.33	27.78	0.11	JD	4	701.85
AURORA ENERGY LLC	6/28/2017	8	7711	31.90	4.58	36.91	26.61	0.11	JD	4	752.00
AURORA ENERGY LLC	6/29/2017	8	7760	31.78	4.09	36.29	27.85	0.10	JD	4	696.20

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	106040.35	7567.00	32.20	4.98	35.56	27.26	0.11

This analysis is representative of the coal shipped. The sulfur content in this shipment was analyzed using sulfur standard ASTM D4239.

Coleen Thompson **Date** 7-5-17

Coleen Thompson

Signature

Appendix E (Coal Sulfur Summary)

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/17 to 12/31/17

Customer	Date	#Cars	BTU	%H20	%A	%V	%C	%S	Site	Bench	Seam	Tons
AURORA ENERGY LLC	7/3/2017	12	7517	32.85	4.69	35.25	27.22	0.11	JD		4	1,086.15
AURORA ENERGY LLC	7/5/2017	13	7551	33.12	4.11	35.68	27.09	0.11	JD		4	1,188.30
AURORA ENERGY LLC	7/6/2017	13	7595	33.11	4.06	35.63	27.20	0.11	JD		4	1,252.50
AURORA ENERGY LLC	7/7/2017	12	7494	33.16	4.13	35.09	27.62	0.11	JD		4	1,164.50
AURORA ENERGY LLC	7/10/2017	11	7516	34.02	4.15	34.55	27.28	0.10	JD		4	1,011.85
AURORA ENERGY LLC	7/11/2017	12	7258	33.79	5.22	35.08	25.92	0.10	JD		4	1,161.40
AURORA ENERGY LLC	7/13/2017	12	6947	34.61	6.24	34.51	24.64	0.10	JD		4	1,145.45
AURORA ENERGY LLC	7/14/2017	11	6816	34.98	6.18	34.21	24.63	0.11	JD		4	1,072.45
AURORA ENERGY LLC	7/17/2017	12	7074	34.52	5.03	34.87	25.58	0.10	JD		4	1,122.60
AURORA ENERGY LLC	7/18/2017	13	7306	33.58	4.88	35.16	26.38	0.11	JD		4	1,222.85
AURORA ENERGY LLC	7/20/2017	13	7165	33.99	5.19	35.42	25.40	0.10	JD		4	1,243.85
AURORA ENERGY LLC	7/25/2017	9	7331	33.62	4.81	35.34	26.24	0.11	JD		4	853.00
AURORA ENERGY LLC	7/26/2017	8	7372	33.16	4.93	35.34	26.58	0.11	JD		4	766.70
AURORA ENERGY LLC	7/27/2017	9	7444	33.20	4.78	35.50	26.53	0.11	JD		4	862.10
AURORA ENERGY LLC	7/28/2017	8	7326	33.62	5.09	35.23	26.07	0.11	JD		4	772.70
AURORA ENERGY LLC	7/31/2017	12	7067	34.65	5.05	34.54	25.77	0.11	JD		4	1,152.10
AURORA ENERGY LLC	8/1/2017	12	7141	33.99	4.94	34.81	26.27	0.11	JD		4	1,150.10
AURORA ENERGY LLC	8/3/2017	12	7164	33.98	5.14	34.57	26.31	0.11	JD		4	1,147.95
AURORA ENERGY LLC	8/4/2017	12	7286	33.90	4.79	35.05	26.27	0.11	JD		4	1,145.30
AURORA ENERGY LLC	8/7/2017	9	7378	33.17	5.03	34.99	26.81	0.11	JD		4	782.15
AURORA ENERGY LLC	8/10/2017	19	7253	33.46	5.18	35.37	25.99	0.11	JD		4	1,810.35
AURORA ENERGY LLC	8/11/2017	20	7318	33.17	5.03	35.36	26.46	0.12	JD		4	1,908.20
AURORA ENERGY LLC	8/14/2017	11	7460	33.07	4.73	35.90	26.91	0.11	JD		4	1,010.35
AURORA ENERGY LLC	8/15/2017	12	7178	34.62	5.07	34.00	26.32	0.12	JD		4	1,140.70
AURORA ENERGY LLC	8/17/2017	12	7233	35.07	4.27	34.48	26.19	0.11	JD		4	1,118.45
AURORA ENERGY LLC	8/18/2017	11	7230	34.34	4.20	35.09	26.38	0.10	JD		4	1,012.25
AURORA ENERGY LLC	8/21/2017	12	7183	34.66	4.57	34.70	26.08	0.10	JD		4	1,132.10
AURORA ENERGY LLC	8/22/2017	11	6965	35.25	5.44	33.99	25.32	0.11	JD		4	1,063.00
AURORA ENERGY LLC	8/24/2017	13	7340	33.83	4.89	35.51	25.78	0.11	JD		4	1,237.30
AURORA ENERGY LLC	8/25/2017	12	7298	33.44	4.79	35.35	26.43	0.10	JD		4	1,143.30

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/17 to 12/31/17

AURORA ENERGY LLC	8/29/2017	13	7624	32.09	3.98	36.19	27.75	0.09	JD	4	1,160.75
AURORA ENERGY LLC	8/30/2017	12	7693	31.67	4.26	35.95	28.12	0.11	JD	4	1,089.50
AURORA ENERGY LLC	8/31/2017	13	7679	31.66	4.54	36.00	27.81	0.12	JD	4	1,198.20
AURORA ENERGY LLC	9/1/2017	16	7556	31.91	4.68	35.57	27.85	0.10	JD	4	1,489.65
AURORA ENERGY LLC	9/5/2017	15	7539	32.49	4.50	35.78	27.23	0.10	JD	4	1,313.40
AURORA ENERGY LLC	9/6/2017	14	7605	32.58	4.13	35.67	27.62	0.10	JD	4	1,306.00
AURORA ENERGY LLC	9/7/2017	14	7651	32.11	4.32	35.95	27.62	0.09	JD	4	1,299.30
AURORA ENERGY LLC	9/8/2017	10	7585	31.81	4.55	35.94	27.71	0.10	JD	4	909.40
AURORA ENERGY LLC	9/11/2017	13	7579	32.39	4.29	35.79	27.54	0.10	JD	4	1,150.80
AURORA ENERGY LLC	9/12/2017	14	7570	32.66	4.03	35.18	28.14	0.09	JD	4	1,235.95
AURORA ENERGY LLC	9/14/2017	14	7678	31.81	4.31	35.96	27.92	0.10	JD	4	1,318.55
AURORA ENERGY LLC	9/18/2017	9	7664	31.53	4.49	35.95	28.03	0.11	JD	4	813.25
AURORA ENERGY LLC	9/19/2017	10	7672	31.57	4.48	35.65	28.30	0.10	JD	4	900.45
AURORA ENERGY LLC	9/21/2017	10	7631	31.22	4.92	36.67	27.20	0.10	JD	4	922.80
AURORA ENERGY LLC	9/22/2017	9	7661	31.07	5.17	36.47	27.30	0.12	JD	4	832.35
AURORA ENERGY LLC	9/25/2017	14	7589	32.54	4.30	35.50	27.67	0.09	JD	4	1,297.15
AURORA ENERGY LLC	9/26/2017	14	7566	32.73	4.36	35.38	27.54	0.10	JD	4	1,304.80
AURORA ENERGY LLC	9/28/2017	12	7661	32.02	4.42	36.00	27.57	0.11	JD	4	1,105.45
AURORA ENERGY LLC	9/29/2017	8	7647	31.64	4.46	35.89	28.01	0.10	JD	4	747.05
AURORA ENERGY LLC	10/2/2017	9	7605	32.57	4.32	35.30	27.82	0.10	JD	4	844.05
AURORA ENERGY LLC	10/5/2017	9	7616	32.89	4.09	35.23	27.80	0.10	JD	4	818.45
AURORA ENERGY LLC	10/6/2017	8	7615	32.44	4.76	35.48	27.33	0.11	JD	4	735.40
AURORA ENERGY LLC	10/9/2017	17	7741	31.67	4.13	36.41	27.80	0.11	JD	4	1,505.25
AURORA ENERGY LLC	10/12/2017	18	7559	32.46	4.67	35.40	27.48	0.11	JD	4	1,721.25
AURORA ENERGY LLC	10/13/2017	17	7502	33.04	4.45	35.28	27.23	0.11	JD	4	1,610.35
AURORA ENERGY LLC	10/16/2017	16	7505	32.67	4.78	35.05	27.50	0.09	JD	4	1,462.45
AURORA ENERGY LLC	10/19/2017	16	7635	32.62	4.06	35.25	28.08	0.09	JD	4	1,483.05
AURORA ENERGY LLC	10/20/2017	16	7771	30.64	4.79	36.18	28.40	0.11	JD	4	1,506.45
AURORA ENERGY LLC	10/23/2017	11	7512	32.84	4.78	34.95	27.43	0.11	JD	4	1,055.65
AURORA ENERGY LLC	10/24/2017	10	7659	32.80	3.76	35.58	27.85	0.10	JD	4	960.95
AURORA ENERGY LLC	10/26/2017	10	7778	31.71	3.93	36.18	28.18	0.11	JD	4	935.50
AURORA ENERGY LLC	10/27/2017	12	7686	31.04	4.57	35.94	28.56	0.11	JD	4	1,090.80

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/17 to 12/31/17

AURORA ENERGY LLC	10/30/2017	17	7638	31.96	4.43	35.98	27.64	0.10	JD	4	1,583.00
AURORA ENERGY LLC	10/31/2017	15	7737	32.08	3.80	35.41	28.72	0.09	JD	4	1,398.05
AURORA ENERGY LLC	11/2/2017	15	7695	31.20	4.63	36.13	28.04	0.10	JD	4	1,375.15
AURORA ENERGY LLC	11/3/2017	16	7568	31.90	5.28	35.76	27.07	0.10	JD	4	1,498.40
AURORA ENERGY LLC	11/6/2017	17	7608	31.44	5.45	34.85	28.27	0.10	JD	4	1,507.55
AURORA ENERGY LLC	11/7/2017	25	7199	33.84	6.32	33.54	26.31	0.09	JD	4	2,432.20
AURORA ENERGY LLC	11/9/2017	7	7639	32.53	4.28	35.73	27.47	0.08	JD	4	600.95
AURORA ENERGY LLC	11/10/2017	17	7717	30.82	4.79	36.38	28.02	0.09	JD	4	1,518.10
AURORA ENERGY LLC	11/13/2017	6	7373	33.38	5.42	34.41	26.79	0.11	JD	4	560.55
AURORA ENERGY LLC	11/14/2017	7	7599	32.39	4.85	35.41	27.35	0.13	JD	4	677.50
AURORA ENERGY LLC	11/16/2017	9	7624	31.94	4.82	35.41	27.84	0.11	JD	4	820.35
AURORA ENERGY LLC	11/20/2017	11	7626	32.25	4.95	35.18	27.62	0.11	JD	4	995.15
AURORA ENERGY LLC	11/21/2017	12	7635	31.90	4.96	35.51	27.63	0.10	JD	4	1,060.50
AURORA ENERGY LLC	11/22/2017	11	7629	31.87	4.81	35.55	27.77	0.10	JD	4	943.05
AURORA ENERGY LLC	11/24/2017	9	7651	31.86	5.02	35.92	27.20	0.12	JD	4	822.90
AURORA ENERGY LLC	11/27/2017	14	7651	31.89	4.89	35.59	27.65	0.12	JD	4	1,257.20
AURORA ENERGY LLC	11/28/2017	20	7615	31.98	4.99	35.71	27.32	0.12	JD	4	1,793.75
AURORA ENERGY LLC	11/30/2017	21	7709	30.84	5.07	35.82	28.27	0.11	JD	4	1,894.15
AURORA ENERGY LLC	12/1/2017	21	7729	30.82	4.85	35.86	28.47	0.12	JD	4	1,908.30
AURORA ENERGY LLC	12/4/2017	17	7826	30.71	4.58	35.95	28.76	0.11	JD	4	1,546.15
AURORA ENERGY LLC	12/5/2017	17	7744	31.15	4.70	35.94	28.21	0.11	JD	4	1,532.85
AURORA ENERGY LLC	12/7/2017	16	7705	31.63	4.59	36.11	27.68	0.11	JD	4	1,428.20
AURORA ENERGY LLC	12/8/2017	15	7601	32.26	4.91	35.14	27.70	0.11	JD	4	1,388.25
AURORA ENERGY LLC	12/11/2017	15	7797	31.63	3.60	35.87	28.90	0.09	JD	4	1,388.65
AURORA ENERGY LLC	12/12/2017	15	7660	30.94	5.44	36.04	27.59	0.10	JD	4	1,419.85
AURORA ENERGY LLC	12/14/2017	16	7730	30.96	5.02	35.96	28.06	0.10	JD	4	1,446.45
AURORA ENERGY LLC	12/18/2017	13	7651	32.79	3.74	34.77	28.71	0.09	JD	4	1,162.00
AURORA ENERGY LLC	12/19/2017	14	7671	32.52	3.99	35.38	28.13	0.09	JD	4	1,281.55
AURORA ENERGY LLC	12/21/2017	14	7678	32.56	4.03	35.53	27.89	0.08	JD	4	1,276.25
AURORA ENERGY LLC	12/22/2017	13	7713	32.05	3.93	35.61	28.41	0.09	JD	4	1,194.20
AURORA ENERGY LLC	12/26/2017	10	7713	32.68	3.47	35.50	28.34	0.08	JD	4	900.45
AURORA ENERGY LLC	12/27/2017	11	7708	32.11	[illegible]	[illegible]	28.38	0.10	JD	4	972.05

Usibelli Coal Mine

Rail Samples

Analysis Results for 7/1/17 to 12/31/17

AURORA ENERGY LLC	12/28/2017	11	7766	31.21	4.38	35.91	28.51	0.09	JD	4	975.75
AURORA ENERGY LLC	12/29/2017	10	7711	31.41	4.64	35.99	27.96	0.10	JD	4	876.15

Weighted Averages Summary

Customer	Tons	BTU	H2O	Ash	Volatiles	Carbon	Sulfur
AURORA ENERGY LLC	114440.00	7529.00	32.52	4.68	35.45	27.36	0.10

This analysis is representative of the coal shipped. The sulfur content in this shipment was analyzed using sulfur standard ASTM D4239.

Ben Ziegman **Date:** 1/4/18

Ben Ziegman

Signature

Appendix D (Professional Memos)

ENVIRONMENT
& HEALTH

MEMO

To **David Fish, Aurora Energy LLC**
From **Till Stoeckenius**
Subject **Summary of issues related to SO_2 precursor demonstration for Fairbanks**

Date November 15, 2018

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The Alaska Department of Environmental Conservation (ADEC) is currently developing a State Implementation Plan (SIP) for the Fairbanks North Star Borough serious $PM_{2.5}$ nonattainment area (NAA). Fairbanks was reclassified from a moderate $PM_{2.5}$ NAA to a serious $PM_{2.5}$ NAA in June 2017; the serious area SIP is due by December 2018.

As provided for in 40 CFR 51.1006, states can reduce the regulatory burden of complying with $PM_{2.5}$ NAA requirements in the Clean Air Act by conducting $PM_{2.5}$ precursor demonstrations showing that one or more precursors involved in formation of secondary $PM_{2.5}$ do not significantly contribute to violations of the $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS). The current ADEC draft serious area SIP preparation plan includes precursor demonstrations for ammonia (NH_3), nitrogen oxides (NO_x), and volatile organic compounds (VOCs) which conclude that each of these three precursors do not significantly contribute to nonattainment. ADEC did not perform a precursor demonstration for sulfur dioxide (SO_2).

A draft Best Available Control Technology (BACT) demonstration completed by the ADEC as required by the CAA for serious NAAs identifies dry sorbent injection as BACT for the four major SO_2 sources in the Fairbanks NAA. In recognition of the possibility that the SIP may include a requirement for SO_2 controls on their sources without a clear indication of the potential benefits of such controls for reducing ambient $PM_{2.5}$ concentrations, owners of the four major SO_2 sources in the Fairbanks NAA requested (via Aurora Energy) Ramboll's assistance with evaluating possible approaches to conducting a successful major source SO_2 precursor demonstration for Fairbanks.

In accordance with our letter agreement with Aurora of 18 September, Ramboll performed research and analysis related to an SO_2 precursor demonstration for the Fairbanks 24-hour $PM_{2.5}$ serious nonattainment area (NAA). Ramboll reviewed documents describing data analysis and modeling conducted by ADEC and its contractors for the 2014 Fairbanks moderate area SIP and draft analyses and plans for developing the serious NAA SIP. This included detailed descriptions of emission inventory development, meteorological and photochemical dispersion modeling methods and related sensitivity analyses, air monitoring data analyses and receptor modeling studies and other related materials. Representatives from Ramboll, Aurora Energy and owners of the other major SO_2 sources located within the Fairbanks NAA, along with ADEC and EPA Region X, participated in a conference call to discuss issues involved in conducting a successful major source SO_2 precursor demonstration. We also had several one-on-one conversations with David Fish of Aurora and Robert Ellerman of EPA Region X. A common theme in these discussions was a significant level of skepticism by ADEC and EPA regarding the likelihood of success in developing an approvable major source SO_2 precursor demonstration for the Fairbanks Serious area SIP given uncertainties about sulfate formation mechanisms under Fairbanks winter conditions. A summary of our findings is provided below.

A key element of a NAA SIP is a demonstration that planned emission reductions will result in attainment of the NAAQS in future years. ADEQ uses a computer model (CMAQ) to carry out this attainment demonstration. CMAQ is a photochemical dispersion model which simulates the transport, dispersion, and chemical transformation of emissions from all sources of $PM_{2.5}$ and $PM_{2.5}$ precursors (NH_3, NO_x, VOC, SO_2) affecting the NAA. In order to complete its work within the available time and resources, ADEC is planning to use the same base year $PM_{2.5}$ episodes (Episode 1: 23 January – 11 February 2008 and Episode 2: 2 – 17 November 2008) and modeling approach for the serious NAA SIP attainment demonstration as were used in the moderate area SIP attainment demonstration. This is despite the limited amount of air quality monitoring data available during these episodes and the fact that air quality conditions in Fairbanks have changed significantly since 2008 due to emission reductions during the intervening years. Monitoring of $PM_{2.5}$ component species was conducted at the State Office Building (SOB) in downtown Fairbanks during the 2008 episodes. These data were used in the moderate area SIP to evaluate the ability of CMAQ to accurately reproduce the observed concentrations of $PM_{2.5}$ and its component species.

As shown in Table 1, comparisons of CMAQ predicted $PM_{2.5}$ with observed $PM_{2.5}$ showed over prediction of organic carbon (OC) and elemental carbon (EC) and under predictions of other PM species, including sulfate (SO_4). These over and underpredictions fortuitously balanced each other out, resulting in an apparently accurate prediction of $PM_{2.5}$ total mass. The prediction errors for individual PM species may be the result of an inaccurate emissions inventory or errors in CMAQ (or in the WRF model used to provide meteorological inputs to CMAQ). Of particular note is that CMAQ predicted very little in situ formation of sulfate from SO_2 emissions due to the lack of available oxidizing agents in the model. In technical documents prepared for the Fairbanks moderate area $PM_{2.5}$ SIP, ADEC concluded that CMAQ is under predicting the amount of secondary sulfate formation under the unique Fairbanks winter conditions due to some unknown SO_2 oxidation pathway.

Table 1. Comparison of observed and predicted PM species concentrations at State Office Building monitoring site (average over days with FRM measurements in both 2008 episodes).

Species	Observed ($\mu g/m^3$)	Predicted ($\mu g/m^3$)	Bias (%)
$PM_{2.5}$ (total)	36.1	35.7	-1%
OC	17.0	24.5	44%
EC	2.3	4.3	87%
SO_4	6.2	2.1	-66%
NO_3	1.6	1.3	-19%
NH_4	3.1	1.2	-61%
OTH	6.3	2.3	-63%

Source: *Addressing the precursor gases for Fairbanks $PM_{2.5}$ State Implementation Plan.* D. Huff, Alaska Department of Environmental Conservation, 25 September 2014, in Reasonably Available Control Measure (RACM) Analysis (Appendix III.D.5.7 to the Fairbanks $PM_{2.5}$ Moderate State Implementation Plan).

In accordance with EPA's precursor demonstration guidelines, a successful precursor demonstration (in this case for SO_2) must show that SO_2 emissions do not contribute significantly to violations of the $PM_{2.5}$ NAAQS. More specifically, for a major source SO_2 precursor demonstration, the guidance requires a demonstration that eliminating SO_2 emission from all major sources within the NAA would not lower $PM_{2.5}$ concentrations by more than an insignificant amount (defined in the guidance as an amount not exceeding 1.5 $\mu g/m^3$).[1] If this "contribution-based" analysis indicates that the impact of major source SO_2 emissions on $PM_{2.5}$ exceeds 1.5 $\mu g/m^3$, then a "sensitivity-based" analysis may be conducted to show that a reduction of SO_2 emissions in the range of 30 – 70% would have only an insignificant impact on lowering $PM_{2.5}$ (also defined as an impact of less than 1.5 $\mu g/m^3$).
The primary obstacle to conducting a credible SO_2 precursor demonstration for Fairbanks cited by ADEC and EPA results from a combination of two facts:

1. the relatively large contribution of sulfate to total $PM_{2.5}$ mass (approximately 17-18% at the SOB) which results in an ammonium sulfate contribution to $PM_{2.5}$ design value[2] that is well in excess of the "insignificant" concentration threshold (1.5 $\mu g/m^3$) cited in EPA's precursor demonstration guidance document and which thus implicates the combined impact of major and minor SO_2 sources as significant contributors to peak $PM_{2.5}$ levels; and
2. the large under prediction of sulfate mass by CMAQ for the 2008 episodes (normalized mean bias of -66%)[3] which leads to the conclusion that the current modeling system (consisting of CMAQ and the emissions estimates and meteorological modeling results used as inputs to CMAQ) does not accurately characterize the contributions of SO_2 sources to the $PM_{2.5}$ design value.

In other words, SO_2 sources are observed to contribute significantly to $PM_{2.5}$ nonattainment and the current modeling system is not sufficiently accurate to provide a reliable estimate of the impacts of emission reductions from SO_2 sources. This makes it difficult to develop a precursor attainment

[1] While the 2016 guidance document recommends using 1.3 μg/m3, EPA recently updated and finalized the technical basis document used to set the recommended level and revised the significance threshold to 1.5 μg/m3.

[2] The design value is the pollutant concentration that is compared to the level of the NAAQS. For the 24-hour $PM_{2.5}$ NAAQS, the design value is the annual 98th percentile daily average concentration averaged over three years.

[3] "Addressing the precursor gases for Fairbanks $PM_{2.5}$ State Implementation Plan", D. Huff 9/25/14, Table 1 (p. 125) in Amendments to State Air Quality Control Plan, Vol. II, Sec. D.5, Appendix III.D.5.7.

demonstration for major sources of SO_2 based on the current data and modeling system that otherwise would be considered sufficiently reliable to gain approval by EPA. We note that this also brings into question the reliability of a modeled attainment demonstration that includes SO_2 controls on major sources.

Despite the difficulties noted above with formulating an approvable major source SO_2 precursor demonstration, data analyses and modeling conducted for the Fairbanks moderate area SIP[4] provide some significant information which suggests that in fact major source SO_2 emissions may not contribute significantly to $PM_{2.5}$ nonattainment. We summarize these key results below:

- Analysis of CMAQ model results by UAF show almost no secondary SO_4 production during the modeled periods. Thus, nearly all of the modeled SO_4 is from primary SO_4 emissions.
- CMAQ underpredicted the SO_4 concentration at the SOB by an average of 3.22 μg/m^3 on days with FRM measurements during the 2008 winter episodes (the average observed SO_4 was 5.25 μg/m^3 while the average predicted SO_4 was 2.03 μg/m^3; note that these values are taken from Table 2 of *Amendments to State Air Quality Control Plan, Vol. II, Sec. D.5, Appendix III.D.5.7* and differ slightly from the values in Table 1; we are still trying to determine the reason for these small differences).[5]
- ADEC concluded that there is likely sufficient excess NH_4 present under episode conditions so that reductions of secondary SO_4 would not lead to significant increases in other secondary species such as ammonium nitrate.[6]
- Both CMAQ point source SO_2 "zero out" runs - in which results from the base case CMAQ run are compared with a CMAQ run in which point source SO_2 emissions are reduced to zero - and CALPUFF model runs show that point sources contribute approximately 22% of the total modeled SO_2 from all sources at the SOB monitor with nearly all of the remaining SO_2 coming from heating oil combustion. [7] Note that the modeled point sources consist of the six major SO_2 sources in the nonattainment area.
- CMAQ zero out runs also show that 5% of primary SO_4 is from point sources. The CMAQ SO_4 prediction at SOB is 2.1 μg/m^3 (Table 1) so the modeled point source primary SO_4 contribution is no more than $0.05 * 2.1 = 0.1$ μg/m^3.
- Comparisons of total $PM_{2.5}$ mass concentration to the NAAQS are made using data from a Federal Reference Method (FRM) monitor. However, $PM_{2.5}$ species composition data are obtained from a SASS sampler. $PM_{2.5}$ measurements from these two different monitoring methods are not directly comparable due to various unavoidable sampling artifacts. In accordance with EPA guideline procedures, ADEC applied adjustments to the $PM_{2.5}$ species composition data from the SASS sampler at the SOB using the SANDWICH algorithm to more accurately reflect the composition of $PM_{2.5}$ samples collected by the FRM monitor. These adjustments account for differences in the amount of nitrate, ammonium, carbon, other primary $PM_{2.5}$ components (OPP), and particle bound water (PBW) captured by the two instruments.
- For purposes of developing the moderate area SIP, ADEC used the available ambient monitoring data processed through the SANDWICH algorithm to develop a "design day" $PM_{2.5}$ composition representative of the average composition of $PM_{2.5}$ during high wintertime $PM_{2.5}$ episodes. ADEC also calculated the applicable $PM_{2.5}$ "design value" which represents the $PM_{2.5}$ total mass concentration that is compared to the level of the NAAQS. For the moderate area SIP, the $PM_{2.5}$ design value at the

[4] https://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-moderate-sip

[5] See Table 2, p. 129 in Amendments to State Air Quality Control Plan, Vol. II, Sec. D.5, Appendix III.D.5.7

[6] Amendments to State Air Quality Control Plan, Vol. II, Sec. D.5, Appendix III.D.5.7, p. 131.

[7] Note that the CALPUFF point source modeling showed that on average only 0.1% of modeled point source SO_2 at SOB during the during Jan. 23rd – Feb 9th 2008 episode days was from the Flint Hills refinery, whereas 36% was from the four power plants and 64% from Ft. Wainwright.

SOB site was determined to be 44.7 μg/m^3. Applying the design day composition to the design value results in the design day $PM_{2.5}$ component concentrations shown in Figure 1.

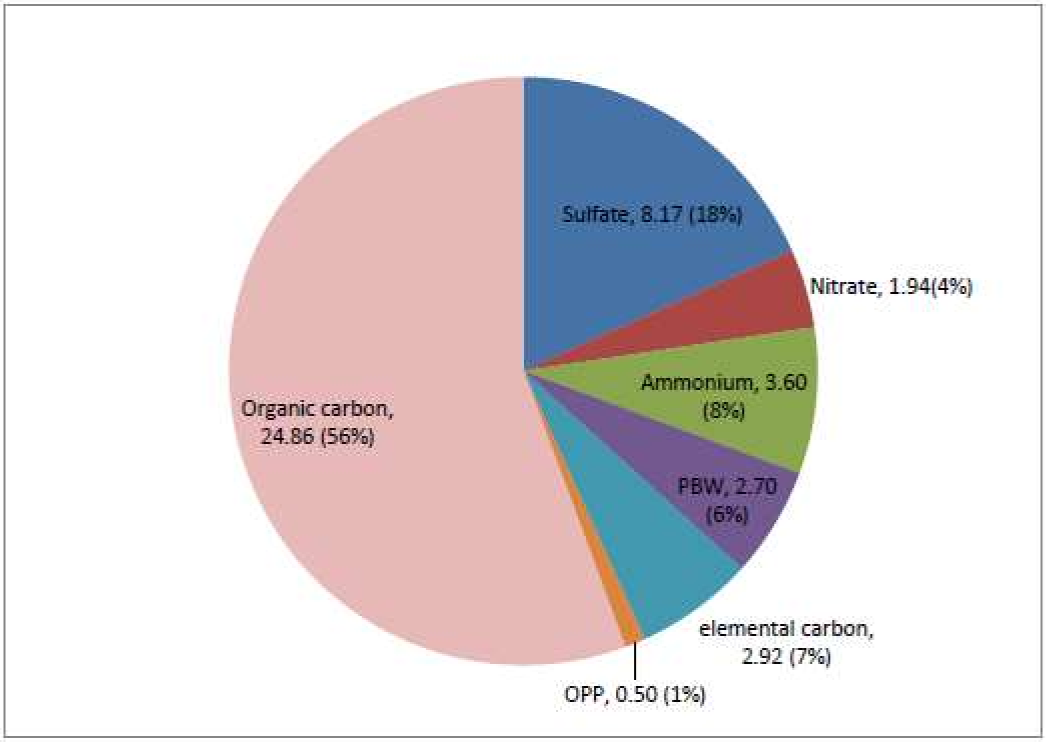

Figure 1. Design day $PM_{2.5}$ speciation at SOB used for the moderate area SIP (source: Appendix III.5.7, p. 122).

- For the design day, the 0.1 μg/m^3 primary sulfate contribution from point sources estimated from the CMAQ zero-out runs noted above scales up to 0.16 μg/m^3 (= 0.1 * 8.17/5.25) where 8.17 μg/m^3 is the amount of SO_4 on the design day and 5.25 μg/m^3 is the average observed amount of SO_4 for the modeled episodes.
- The design day PM composition shown in Figure 1 includes 8.17 μg/m^3 SO_4. The correspondingly scaled SO_4 that is unaccounted for in the CMAQ results is 3.22 * (8.17/5.25) = 5.01 μg/m^3. At one extreme, all of this "unexplained" SO_4 could be attributed to emissions from point sources (i.e., the major SO_2 sources). Perhaps more realistically, one could estimate that 22% of the unexplained SO_4 (0.22 * 5.01 = 1.1 μg/m^3) is from point sources, in keeping with the modeled 22% contribution of point sources to SO_2 noted above. Assuming all SO_4 is in the form of ammonium sulfate, this would be equivalent to a 1.1 * (132/96) = 1.51 μg/m^3 contribution to $PM_{2.5}$, where the factor 132/96 represents the molecular weight ratio of ammonium sulfate to sulfate. Adding to this the amount of particle bound water (PBW) associated with ammonium sulfate assumed in the SANDWICH estimate of FRM measurement (2/3 * 2.70 μg/m^3 = 1.80 μg/m^3 assumed to be associated with 8.17 μg/m^3 of SO_4 so 1.1 μg/m^3 * (1.80/8.17) = 0.24 μg/m^3 of PBW associated with the point source SO_4) results in a total point source ammonium sulfate with associated PBW contribution of 1.51 + 0.24 = 1.75 μg/m^3.
- The above simple "contribution-based" precursor demonstration result indicates that the major source SO_2 contribution is slightly above the "insignificant contribution" threshold (1.5 μg/m^3) cited

in EPA's Precursor Demonstration Guidance. However, the EPA guidance allows for a "sensitivity-based" precursor demonstration in which the reduction in $PM_{2.5}$ concentration resulting from a 30, 50, or 70% reduction in SO_2 emissions is compared to the 1.5 μg/m^3 significance threshold. Based on a linear extrapolation from the above analysis, a maximum 70% reduction in major source SO_2 emissions would be expected to produce a 1.23 μg/m^3 decrease in $PM_{2.5}$, which is below the 1.5 μg/m^3 significance threshold. In other words, the $PM_{2.5}$ design value is relatively insensitive to even a large (70%) reduction in major source SO_2 emissions.

Although the above result for a sensitivity-based SO_2 precursor demonstration is encouraging, it must be noted that the precursor demonstration guideline suggests that ADEC may still need to include consideration of the feasibility of major source SO_2 reduction measures in its SIP, even if the sensitivity-based demonstration produces a result below the significance threshold. This may be particularly important for Fairbanks given uncertainties about the amount of SO_4 actually contributed by the major sources.

It is also important to keep in mind that conditions have changed in Fairbanks since 2008 and the new Serious area SIP will use a base year of 2013 to represent "current conditions". Updated area source emissions will be modeled but episodic point source emissions will be based on the 2008 point source inventory. Modeling results are not yet available, so it is not possible to know how the above results might differ for the new base year.

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
Air Permits Program

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION for Chena Power Plant Aurora Energy, LLC.

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Date: May 10, 2019

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Abbreviations/Acronyms

AAC ....Alaska Administrative Code
AAAQS ....Alaska Ambient Air Quality Standards
Department ....Alaska Department of Environmental Conservation
BACT ....Best Available Control Technology
CFB……………………Circulating Fluidized Bed
CFR. ....Code of Federal Regulations
Cyclones……………….Mechanical Separators
DFP……………………Diesel Particulate Filter
DLN..............................Dry Low NOx
DOC…………………...Diesel Oxidation Catalyst
EPA ....Environmental Protection Agency
ESP…………………….Electrostatic Precipitator
EU.................................Emission Unit
FITR…………………...Fuel Injection Timing Retard
GCPs…………………..Good Combustion Practices
HAP...............................Hazardous Air Pollutant
ITR…………………….Ignition Timing Retard
LEA……………………Low Excess Air
LNB……………………Low NOx Burners
MR&Rs ....Monitoring, Recording, and Reporting
NESHAPS ....National Emission Standards for Hazardous Air Pollutants
NSCR………………….Non-Selective Catalytic Reduction
NSPS ....New Source Performance Standards
ORL...............................Owner Requested Limit
PSD................................Prevention of Significant Deterioration
PTE................................Potential to Emit
RICE, ICE ....Reciprocating Internal Combustion Engine, Internal Combustion Engine
SCR ....Selective Catalytic Reduction
SIP ....Alaska State Implementation Plan
SNCR………………….Selective Non-Catalytic Reduction
ULSD ....Ultra Low Sulfur Diesel

Units and Measures

gal/hr..............................gallons per hour
g/kWh............................grams per kilowatt hour
g/hp-hr ....grams per horsepower hour
hr/day.............................hours per day
hr/yr ....hours per year
hp...................................horsepower
lb/hr ....pounds per hour
lb/MMBtu......................pounds per million British thermal units
lb/1000 gal.....................pounds per 1,000 gallons
kW ....kilowatts
MMBtu/hr......................million British thermal units per hour
MMscf/hr.......................million standard cubic feet per hour
ppmv..............................parts per million by volume
tpy.................................tons per year

Pollutants

CO ....Carbon Monoxide
HAP...............................Hazardous Air Pollutant
NOx ....Oxides of Nitrogen
SO_2 ....Sulfur Dioxide
PM-2.5...........................Particulate Matter with an aerodynamic diameter not exceeding 2.5 microns
PM-10............................Particulate Matter with an aerodynamic diameter not exceeding 10 microns

1. INTRODUCTION

Chena Power Plant is a stationary source owned by Aurora Energy, LLC (Aurora) which consists of four boilers. Emission Units (EUs) 4 through 6, also identified as Chena 1, 2, and 3, are coal-fired overfeed traveling grate stokers with a maximum steam production rating of 50,000 lbs/hr each. Maximum design power production is 5 megawatts (MW) each. EU 4 was installed in 1954, while EUs 5 and 6 were installed in 1952. EU 7, also identified as Chena 5, is a coal-fired, spreader stoker boiler with a maximum steam production rating of 200,000 lbs/hr and maximum power production rating of 20 MW. Chena 5 was installed in 1970. Maximum coal consumption is 284,557 tons of coal per year, based on the capacities of EUs 4 through 7. Coal receiving and storage (handling) facilities are located on the north bank of the Chena River, and consist of a rail car receiving station, enclosed coal crusher (receiving building), open storage piles, conveyors, and elevators. Coal is transported by conveyors over the Chena River to the Chena Power Plant, located just above the south bank. In the late 1980's, the coal handling system was renovated.

In a letter dated April 24, 2015, the Alaska Department of Environmental Conservation (Department) requested the stationary sources expected to be major stationary sources in the particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers (PM-2.5) serious nonattainment area perform a voluntary Best Available Control Technology (BACT) review in support of the state agency's required SIP submittal once the nonattainment area is re-classified as a Serious PM-2.5 nonattainment area. The designation of the area as "Serious" with regard to nonattainment of the 2006 24-hour PM-2.5 ambient air quality standards was published in Federal Register Vol. 82, No. 89, May 10, 2017, pages 21703-21706, with an effective date of June 9, 2017. [1]

This report addresses the significant emissions units (EUs) listed in Operating Permit No. AQ0315TVP03, Revision 1. This report provides the Department's review of the BACT analysis for oxides of nitrogen (NOx) and sulfur dioxide (SO_2) emissions, which are precursor pollutants that can form PM-2.5 in the atmosphere post combustion.

The following sections review Chena Power Plant's BACT analysis for technical accuracy and adherence to accepted engineering cost estimation practices.

2. BACT EVALUATION

A BACT analysis is an evaluation of all available control options for equipment emitting the triggered pollutants and a process for selecting the best option based on feasibility, economics, energy, and other impacts. 40 CFR 52.21(b)(12) defines BACT as a site-specific determination on a case-by-case basis. The Department's goal is to identify BACT for the permanent EUs at Chena Power Plant that emit NOx and SO_2, establish emission limits which represent BACT, and assess the level of monitoring, recordkeeping, and reporting (MR&Rs) necessary to ensure Chena Power Plant applies BACT for the EUs. The Department based the BACT review on the five-step top-down approach set forth in Federal Register Volume 61, Number 142, July 23, 1996 (Environmental Protection Agency).

[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 (https://dec.alaska.gov/air/anpms/comm/docs/2017-09391-CFR.pdf)

Table **A** present the EUs subject to BACT review.

Table A: Emission Units Subject to BACT Review

EU	Emission Unit Name	Emission Unit Description	Rating/Size	Installation or Construction Date
4	Chena 1 Coal Fired Boiler	Full Stream Baghouse Exhaust	76 MMBtu/hr	1954
5	Chena 2 Coal Fired Boiler	Full Stream Baghouse Exhaust	76 MMBtu/hr	1952
6	Chena 3 Coal Fired Boiler	Full Stream Baghouse Exhaust	76 MMBtu/hr	1952
7	Chena 5 Coal Fired Boiler	Full Stream Baghouse Exhaust	269 MMBtu/hr	1970

Five-Step BACT Determinations

The following sections explain the steps used to determine BACT for NOx and SO_2 for the applicable equipment.

Step 1 Identify All Potentially Available Control Technologies

The Department identifies all available control technologies for the EUs and the pollutant under consideration. This includes technologies used throughout the world or emission reductions through the application of available control techniques, changes in process design, and/or operational limitations. To assist in identifying available controls, the Department reviews available controls listed on the Reasonably Available Control Technology (RACT), BACT, and Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC). The RBLC is an EPA database where permitting agencies nationwide post imposed BACT for PSD sources. It is usually the first stop for BACT research. In addition to the RBLC search, the Department used several search engines to look for emerging and tried technologies used to control NOx and SO_2 emissions from equipment similar to those listed in
Table **A**.

Step 2 Eliminate Technically Infeasible Control Technologies

The Department evaluates the technical feasibility of each control technology based on source specific factors in relation to each EU subject to BACT. Based on sound documentation and demonstration, the Department eliminates control technologies deemed technically infeasible due to physical, chemical, and engineering difficulties.

Step 3 Rank the Remaining Control Technologies by Control Effectiveness

The Department ranks the remaining control technologies in order of control effectiveness with the most effective at the top.

Step 4 Evaluate the Most Effective Controls and Document the Results as Necessary

The Department reviews the detailed information in the BACT analysis about the control efficiency, emission rate, emission reduction, cost, environmental, and energy impacts for each technology to decide the final level of control. The analysis must present an objective evaluation of both the beneficial and adverse energy, environmental, and economic impacts. A proposal to use the most effective option does not need to provide the detailed information for the less effective options. If cost is not an issue, a cost analysis is not required. Cost effectiveness for a control option is defined as the total net annualized cost of control divided by the tons of pollutant removed per year. Annualized cost includes annualized equipment purchase, erection, electrical, piping, insulation, painting, site preparation, buildings, supervision, transportation, operation, maintenance, replacement parts, overhead, raw materials, utilities, engineering, start-up costs, financing costs, and other contingencies related to the control option. Sections 3 and 4 present the Department's BACT Determinations for NOx and SO_2.

Step 5 Select BACT

The Department selects the most effective control option not eliminated in Step 4 as BACT for the pollutant and EU under review and lists the final BACT requirements determined for each EU in this step. A project may achieve emission reductions through the application of available technologies, changes in process design, and/or operational limitations. The Department reviewed Aurora's BACT analysis and made BACT determinations for NOx and SO_2 for the Chena Power Plant. These BACT determinations are based on the information submitted by Aurora in their analysis, information from vendors, suppliers, sub-contractors, RBLC, and an exhaustive internet search.

3. BACT DETERMINATION FOR NOx

The NOx controls proposed in this section are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC is planning to submit with the Serious SIP a final precursor demonstration as justification not to require NOx controls. Please see the precursor demonstration for NOx posted at http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip-development. The PM2.5 NAAQS Final SIP Requirements Rule states if the state determines through a precursor demonstration that controls for a precursor gas are not needed for attaining the standard, then the controls identified as BACT/BACM or Most Stringent Measure for the precursor gas are not required to be implemented.[2] Final approval of the precursor demonstration is at the time of the Serious SIP approval.

Chena Power Plant has three existing 76 million British Thermal Units (MMBtu)/hr overfeed traveling grate stoker type boilers and one 269 MMBtu/hr spreader-stoker type boiler that burns coal to produce steam for stationary source-wide heating and power. The Department based its NOx assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by Golden Valley Electric Association (GVEA) for the North Pole Power Plant and Zehnder Facility, Aurora Energy, LLC (Aurora) for the Chena Power Plant, U.S. Army Corps of Engineers (US Army) for Fort Wainwright, and the University of Alaska Fairbanks (UAF) for the Fairbanks Campus Power Plant.

3.1 NOx BACT for the Industrial Coal-Fired Boilers

Possible NOx emission control technologies for coal fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 11.110

[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf

for Coal Combustion in Industrial Size Boilers and Furnaces. The search results for coal-fired boilers are summarized in Table 3-1.

Table 3-1. RBLC Summary of NOx Control for Industrial Coal-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Selective Catalytic Reduction	9	0.05 – 0.08
Selective Non-Catalytic Reduction	18	0.07 – 0.36
Low NOx Burners	18	0.07 – 0.3
Overfire Air	8	0.07 – 0.3
Good Combustion Practices	2	0.1 – 0.6

RBLC Review
A review of similar units in the RBLC indicates selective catalytic reduction, selective non-catalytic reduction, low NOx burners, overfire air, and good combustion practices are the principle NOx control technologies installed on industrial coal-fired boilers. The lowest NOx emission rate in the RBLC is 0.05 lb/MMBtu.

Step 1- Identification of NOx Control Technologies for the Industrial Coal-Fired Boilers
From research, the Department identified the following technologies as available for control of NOx emissions from the industrial coal-fired boilers:

(a) Selective Catalytic Reduction (SCR)[3]
SCR is a post-combustion gas treatment technique for reducing nitric oxide (NO) and nitrogen dioxide (NO_2) in the boiler exhaust stream to molecular nitrogen (N_2), water, and oxygen (O_2). In the SCR process, aqueous or anhydrous ammonia (NH_3) is injected into the flue gas upstream of a catalyst bed. The catalyst lowers the activation energy of the NOx decomposition reaction. NOx and NH_3 combine at the catalyst surface forming an ammonium salt intermediate, which subsequently decomposes to produce elemental N_2 and water. Depending on the overall NH_3-to-NOx ratio, removal efficiencies are generally 80 to 90 percent. Challenges associated with using SCR on boilers include a narrow window of acceptable inlet and exhaust temperatures (500°F to 800°F), emission of NH_3 into the atmosphere (NH_3 slip) caused by non-stoichiometric reduction reaction, and disposal of depleted catalysts. The Department considers SCR a technically feasible control technology for the industrial coal-fired boilers.

(b) Selective Non-Catalytic Reduction (SNCR)[4]
SNCR involves the non-catalytic decomposition of NOx in the flue gas to N_2 and water using reducing agents such as urea or NH_3. The process utilizes a gas phase homogeneous reaction between NOx and the reducing agent within a specific temperature window. The reducing agent must be injected into the flue gas at a location in the unit that provides the optimum reaction temperature and residence time. The NH_3 process (trade name-Thermal DeNOx) requires a reaction temperature window of 1,600°F to 2,200°F. In the urea process (trade name–NO_xOUT), the optimum temperature ranges between 1,600°F and 2,100°F. Expected NOx removal efficiencies are typically

[3] https://www3.epa.gov/ttncatc1/dir1/fscr.pdf
[4] https://www3.epa.gov/ttncatc1/dir1/fsncr.pdf

between 40 to 62 percent, according to the RBLC, or between 30 and 50 percent reduction, according to the EPA fact sheet (EPA-452/F-03-031). The Department considers SNCR a technically feasible control technology for the industrial coal-fired boilers.

(c) Non-Selective Catalytic Reduction (NSCR)
NSCR simultaneously reduces NOx and oxidizes CO and hydrocarbons in the exhaust gas to N_2, carbon dioxide (CO_2), and water. The catalyst, usually a noble metal, causes the reducing gases in the exhaust stream (hydrogen, methane, and CO) to reduce both NO and NO_2 to N_2 at a temperature between 800°F and 1,200°F, below the expected temperature of the coal-fired boiler flue gas. NSCR requires a low excess O_2 concentration in the exhaust gas stream to be effective because the O_2 must be depleted before the reduction chemistry can proceed. NSCR is only effective with rich-burn gas-fired units that operate at all times with an air/fuel ratio controller at or close to stoichiometric conditions. Coal-fired boilers operate under conditions far more fuel-lean than required to support NSCR. The Department's research did not identify NSCR as a control technology used to control NOx emissions from large coal fired boilers installed at any facility after 2005. The Department does not consider NSCR a technically feasible control technology for the industrial coal-fired boilers.

(d) Low NOx Burners (LNBs)
Using LNBs can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature. Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one installation to another. Typical reductions range from 40% - 60% but under certain conditions, higher reductions are possible. Air staging or two-stage combustion, is generally described as the introduction of overfire air into the boiler or furnace. Overfire air is the injection of air above the main combustion zone. As indicated by EPA's AP-42, LNBs are applicable to tangential and wall-fired boilers of various sizes but are not applicable to other boiler types such as cyclone furnaces or stokers. The Department does not consider LNBs a technically feasible control technology for stoker type coal-fired boilers.

(e) Circulating Fluidized Bed (CFB)
In a fluidized bed combustor, fuel is introduced to a bed of either sorbent (limestone) or inert material (usually sand) that is fluidized by an upward flow of air. This upward air flow allows for better mixing of the gas and solids to create a better heat transfer and chemical reactions. Combustion takes place in the bed at a lower temperature than other boiler types which lowers the formation of thermally generated NOx. The Department does not consider CFB a technically feasible control technology to retrofit existing coal-fired boilers. For the purposes of this report, a control technology does not include passive control measures that act to prevent pollutants from forming or the use of combustion or other process design features or characteristics. The Department does not

consider CFB a technically feasible control technology to retrofit the existing coal-fired boilers.

(f) Low Excess Air (LEA)
Boiler operation with low excess air is considered an integral part of good combustion practices because this process can maximize the boiler efficiency while controlling the formation of NOx. Boilers operated with five to seven percent excess air typically have peak NOx formation from both peak combustion temperatures and chemical reactions. At both lower and higher excess air concentrations the formation of NOx is reduced. At higher levels of excess air, an increase in the formation of CO occurs. CO can increase exponentially at very high levels of excess air and the combustion efficiency is greatly reduced. As a result, the preference is to reduce excess air such that both NOx and CO generation is minimized and the boiler efficiency is optimized. Only one RLBC entry identified low excess air technology as a NOx control alternative for a mass-feed stoker designed boiler. Boilers are regularly designed to operate with low excess air as described in the previous LNB discussion. The Department considers LEA a technically feasible control technology for the industrial coal-fired boilers.

(g) Good Combustion Practices (GCPs)
GCPs typically include the following elements:

1. Sufficient residence time to complete combustion;
2. Providing and maintaining proper air/fuel ratio;
3. High temperatures and low oxygen levels in the primary combustion zone; and
4. High enough overall excess oxygen levels to complete combustion and maximize thermal efficiency.

Combustion efficiency is dependent on the gas residence time, the combustion temperature, and the amount of mixing in the combustion zone. GCPs are accomplished primarily through combustion chamber design as it relates to residence time, combustion temperature, air-to-fuel mixing, and excess oxygen levels. The Department considers GCPs a technically feasible control option for the coal-fired boilers.

(h) Fuel Switching
This evaluation considers retrofit of existing coal-fired boilers. It is assumed that use of another type of coal would not reduce NOx emissions. Therefore, the Department does not consider the use of an alternate fuel to be a technically feasible control technology for the industrial coal-fired boilers.

(i) Steam / Water Injection
Steam/water injection into the combustion zone reduces the firing temperature in the combustion chamber and has been traditionally associated with reducing NOx emissions from gas combustion turbines but not coal-fired boilers. In addition, steam/water has several disadvantages, including increases in carbon monoxide and un-burned hydrocarbon emissions and increased fuel consumption. Further, the Department found that steam or water injection is not listed in the EPA RBLC for use in any coal-fired boilers and it would be less efficient at controlling NOx emissions than SCR. Therefore,

the Department does not consider steam or water injection to be a technically feasible control option for the existing coal-fired boilers.

(j) Reburn
Reburn is a combustion hardware modification in which the NOx produced in the main combustion zone is reduced in a second combustion zone downstream. This technique involves withholding up to 40 percent (at full load) of the heat input to the main combustion zone and introducing that heat input above the top row of burners to create a reburn zone. Reburn fuel (natural gas, oil, or pulverized coal) is injected with either air or flue gas to create a fuel-rich zone that reduces the NOx created in the main combustion zone to nitrogen and water vapor. The fuel-rich combustion gases from the reburn zone are completely combusted by injecting overfire air above the reburn zone. Reburn may be applicable to many boiler types firing coal as the primary fuel, including tangential, wall-fired, and cyclone boilers. However, the application and effectiveness are site-specific because each boiler is originally designed to achieve specific steam conditions and capacity which may be altered due to reburn. Commercial experience is limited; however, this limited experience does indicate NOx reduction of 50 to 60 percent from uncontrolled levels may be achieved. Reburn combustion control would require significant changes to the design of the existing boilers. Therefore, the Department does not consider reburn to be a technically feasible control technology to retrofit the existing industrial coal-fired boilers.

Step 2 - Elimination of Technically Infeasible NOx Control Options for Coal-Fired Boilers
As explained in Step 1 of Section 3.1, the Department does not consider non-selective catalytic reduction, low NOx burners, circulating fluidized beds, fuel switching, steam/water injection, or reburn as technically feasible technologies to control NO_x emissions from existing industrial coal-fired boilers.

Step 3 - Ranking of Remaining NOx Control Technologies for Coal-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of NOx emissions from the coal-fired boilers:

(a)	Selective Catalytic Reduction	(70% - 90% Control)
(b)	Selective Non-Catalytic Reduction	(30% - 50% Control)
(g)	Good Combustion Practices	(Less than 40% Control)
(f)	Low Excess Air	(10% - 20% Control)

Step 4 - Evaluate the Most Effective Controls

Aurora BACT Proposal

Aurora provided an economic analysis for the installation of SCR on all four boilers combined (EUs 4 through 7). Aurora also provided economic analyses for the installation of SNCR on the three 76 MMBtu/hr boilers (EUs 4 through 6), the 269 MMBtu/hr boiler (EU 7), and all four boilers combined (EUs 4 through 7). A summary of the analyses is shown in Table 3-2.

Table 3-2. Aurora Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR (EUs 4 – 7)	784	564	$73,069,750	$15,994,554	$28,347
SNCR (EUs 7)	342	103	$2,792,684	$784,066	$7,649
SNCR (EUs 4 – 6)	439	132	$4,906,782	$1,589,578	$12,059
SNCR (EUs 4 – 7)	781	234	$7,699,466	$2,373,645	$10,130

Aurora's economic analysis indicates the level of NOx reduction does not justify the use of SCR or SNCR for the coal-fired boilers based on the excessive cost per ton of NOx removed per year.

Aurora proposes the following as BACT for NOx emissions from the coal-fired boilers:

(a) NOx emissions from the operation of the coal-fired boilers will be controlled with existing combustion controls;

(b) NOx emissions from the coal-fired boilers will not exceed 0.36 lb/MMBtu; and

(c) Initial compliance with the proposed NOx emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

Department Evaluation of BACT for NOx Emissions from the Industrial Coal-Fired Boilers
The Department revised the cost analyses provided by Aurora for the installation of SCR and SNCR using the cost estimating procedures identified in EPA's May 2016 Air Pollution Control Cost Estimation Spreadsheets for Selective Catalytic Reduction[5] and Selective Non-Catalytic Reduction,[6] using the unrestricted potential to emit of the four coal-fired boilers, a baseline emission rate of 0.437 lb NOx/MMBtu,[7] a retrofit factor of 1.5 for projects requiring a difficult retrofit, a NOx removal efficiency of 90% and 50% for SCR and SNCR respectively, and a 20 year equipment life. A summary of the analysis is shown below:

Table 3-3. Department Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
SCR	940	846	$26,341,430	$3,403,675	$4,023
SNCR	940	470	$5,924,241	$1,046,952	$2,227
Capital Recovery Factor = 0.0837 (5.5% interest rate for a 20 year equipment life)					

The Department's economic analysis indicates the level of NOx reduction justifies the use of SCR or SNCR as BACT for the coal-fired boilers located in the Serious PM-2.5 nonattainment area.

5 https://www3.epa.gov/ttn/ecas/docs/scr_cost_manual_spreadsheet_2016_vf.xlsm
6 https://www3.epa.gov/ttn/ecas/docs/sncr_cost_manual_spreadsheet_2016_vf.xlsm
7 Emission rate from most recent NOx and SO_2 source test accepted by the Department for permitting applicability, which occurred on November 19, 2011.

Step 5 - Selection of NOx BACT for the Industrial Coal-Fired Boilers
The Department's finding is that selective catalytic reduction and selective non-catalytic reduction are both economically and technically feasible control technologies for NOx. Since selective catalytic reduction has a higher control efficiency, it is selected as BACT to control NOx emissions from the industrial coal-fired boilers.

The Department's finding is that BACT for NOx emissions from the coal-fired boilers is as follows:

(a) NOx emissions from EUs 4 through 7 shall be controlled by operating and maintaining SCR at all times the units are in operation;

(b) NOx emissions from DU EUs 4 through 7 shall not exceed 0.05 lb/MMBtu averaged over a 3-hour period; and

(c) Initial compliance with the proposed NOx emission rate will be demonstrated by conducting a performance test to obtain an emission rate.

Table 3-4 lists the proposed NOx BACT determination for this facility along with those for other coal-fired boilers in the Serious PM-2.5 nonattainment area.

Table 3-4. Comparison of NOx BACT for Coal-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	6 Coal-Fired Boilers	1,380 MMBtu/hr	0.06 lb/MMBtu[8]	Selective Catalytic Reduction
UAF	Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.02 lb/MMBtu[9]	Selective Catalytic Reduction
Chena	4 Coal-Fired Boilers	497 MMBtu/hr	0.05 lb/MMBtu[10]	Selective Catalytic Reduction

4. BACT DETERMINATION FOR SO_2

The Department based its SO_2 assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by GVEA for the North Pole Power Plant and Zehnder Facility, Aurora for the Chena Power Plant, US Army for Fort Wainwright, and UAF for the Combined Heat and Power Plant.

4.1 SO_2 BACT for the Industrial Coal-Fired Boilers

Possible SO_2 emission control technologies for coal-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 11.110, Coal Combustion in Industrial Size Boilers and Furnaces. The search results for the coal-fired boilers are summarized in Table 4-1.

[8] Calculated using a 90% NOx control efficiency for SCR with uncontrolled emission factor from AP-42 Table 1.1-3 for spreader stoker sub-bituminous coal (8.8 lb NOx/ton) and converted to lb/MMBtu using heat value for Usibelli Coal of 7,560 Btu/lb, http://www.usibelli.com/coal/data-sheet.

[9] Calculated using a 90% NOx control efficiency for SCR with uncontrolled emission rate from 40 C.F.R. 60.44b(l)(1) [NSPS Subpart Db].

[10] Calculated using a 90% NOx control efficiency for SCR with uncontrolled emission rate from most recent NOx source test, which occurred on Oct 27, 2018.

Table 4-1. RBLC Summary of SO_2 Control for Industrial Coal-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Flue Gas Desulfurization / Scrubber / Spray Dryer	10	0.06 – 0.12
Limestone Injection	10	0.055 – 0.114
Low Sulfur Coal	4	0.06 – 1.2

RBLC Review
A review of similar units in the RBLC indicates flue gas desulfurization and low sulfur coal are the principle SO_2 control technologies installed on industrial coal-fired boilers. The lowest SO_2 emission rate in the RBLC is 0.055 lb/MMBtu.

Step 1- Identification of SO_2 Control Technology for the Coal-Fired Boilers
From research, the Department identified the following technologies as available for the control of SO_2 emissions from the industrial coal-fired boilers:

(a) Wet Scrubbers
Post combustion flue gas desulfurization techniques can remove SO_2 formed during combustion by using an alkaline reagent to absorb SO_2 in the flue gas. Flue gasses can be treated using wet, dry, or semi-dry desulfurization processes. In the wet scrubbing system, flue gas is contacted with a solution or slurry of alkaline material in a vessel providing a relatively long residence time. The SO_2 in the flue reacts with the alkali solution or slurry by adsorption and/or absorption mechanisms to form liquid-phase salts. These salts are dried to about one percent free moisture by the heat in the flue gas. These solids are entrained in the flue gas and carried from the dryer to a PM collection device, such as a baghouse.

The lime and limestone wet scrubbing process uses a slurry of calcium oxide or limestone to absorb SO_2 in a wet scrubber. Control efficiencies in excess of 91 percent for lime and 94 percent for limestone over extended periods are possible. Sodium scrubbing processes generally employ a wet scrubbing solution of sodium hydroxide or sodium carbonate to absorb SO_2 from the flue gas. Sodium scrubbers are generally limited to smaller sources because of high reagent costs and can have SO_2 removal efficiencies of up to 96.2 percent. The double or dual alkali system uses a clear sodium alkali solution for SO_2 removal followed by a regeneration step using lime or limestone to recover the sodium alkali and produce a calcium sulfite and sulfate sludge. SO_2 removal efficiencies of 90 to 96 percent are possible. The Department considers flue gas desulfurization with a wet scrubber a technically feasible control technology for the industrial coal-fired boilers.

(b) Spray Dry Absorbers (SDA)
In SDA systems, an aqueous sorbent slurry with a higher sorbent ratio than that of a wet scrubber is injected into the hot flue gases. As the slurry mixes with the flue gas, the water is evaporated and the process forms a dry waste which is collected in a baghouse or electrostatic precipitator. The Department considers flue gas desulfurization with an SDA system a technically feasible control technology for the industrial coal-fired boilers.

(c) Dry Sorbent Injection (DSI)
DSI systems pneumatically inject a powdered sorbent directly into the furnace, the economizer, or the downstream ductwork depending on the temperature and the type of sorbent utilized. The dry waste is removed using a baghouse or electrostatic precipitator. Spray drying technology is less complex mechanically, and no more complex chemically, than wet scrubbing systems. The main advantages of the spray dryer is that this technology avoids two problems associated with wet scrubbing, corrosion and liquid waste treatment. Spray dry scrubbers are mostly used for small to medium capacity boilers and are preferable for retrofits. The Department considers flue gas desulfurization with DSI a technically feasible control technology for the industrial coal-fired boilers.

(d) Low Sulfur Coal
Aurora purchases coal from the Usibelli Coal Mine located in Healy, Alaska. This coal mine is located 115 miles south of Fairbanks. The coal mined at Usibelli is sub-bituminous coal and has a relatively low sulfur content with guarantees of less than 0.4 percent by weight. Usibelli Coal Data Sheets indicate a range of 0.08 to 0.28 percent Gross As Received (GAR) percent Sulfur (%S). According to the U.S. Geological Survey, coal with less than one percent sulfur is classified as low sulfur coal. The Department considers the use of low sulfur coal a technically feasible control technology for the industrial coal-fired boilers.

(e) Good Combustion Practices (GCPs)
The theory of GCPs was discussed in detail in the NOx BACT for the industrial coal-fired boilers and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control option for the industrial coal-fired boilers.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for Coal-Fired Boilers
All identified control devices are technically feasible for the industrial coal-fired boilers.

Step 3 - Rank the Remaining SO_2 Control Technologies for Industrial Coal-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of SO_2 emissions from the coal-fired industrial boilers:

(a)	Wet Scrubbers	(99% Control)
(b)	Spray Dry Absorbers	(90% Control)
(c)	Dry Sorbent Injection (Duct Sorbent Injection)	(50 – 80% Control)
(d)	Low Sulfur Coal	(30% Control)
(e)	Good Combustion Practices	(Less than 40% Control)

Step 4 - Evaluate the Most Effective Controls

Aurora BACT Proposal

Aurora provided an economic analysis of the installation of wet and dry scrubber systems. A summary of the analysis is shown below:

Table 4-2. Aurora Economic Analysis for Technically Feasible SO_2 Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Wet Scrubber (Limestone Forced Oxidation)	830	415	$88,476,054	???	$74,146
Spray Dry Absorber (Lime Spray Dryer)	830	614	$74,161,357	???	???
Dry Sorbent Injection	830	332	$32,500,898	$9,129,760	$27,493
Capital Recovery Factor = 0.1627% of total capital investment (10% for a 10 year life cycle)					

Aurora contends that the economic analysis indicates the level of SO_2 reduction does not justify the use of wet scrubbers, semi-dry scrubbers, or dry scrubber systems (dry-sorbent injection) for the coal-fired boilers based on the excessive cost per ton of SO_2 removed per year.

Aurora proposes the following as BACT for SO_2 emissions from the coal-fired boilers:

(a) SO_2 emissions from the coal-fired boilers will be controlled by burning low sulfur coal (less than 0.2% S by weight) at all times the boilers are in operation; and

(b) SO_2 emissions from the coal-fired boilers will not exceed 0.39 lb/MMBtu.

Department Evaluation of BACT for SO_2 Emissions from Industrial Coal-Fired Boilers

The Department revised the cost analysis provided for the installation of wet scrubbers, semi-dry scrubbers (spray dry absorbers), and dry scrubbers (dry sorbent injection) using the combined unrestricted potential to emit for the four coal-fired boilers, a baseline emission rate of 0.472 lb SO_2/MMBtu,[7] a retrofit factor of 1.5 for a difficult retrofit, a SO_2 removal efficiency of 99%, 90% and 80% for wet scrubbers, spray dry absorbers and dry sorbent injection respectively, an interest rate of 5.5% (current bank prime interest rate), and a 15 year equipment life. A summary of the analysis is shown below:

Table 4-3. Department Economic Analysis for Technically Feasible SO_2 Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
Wet Scrubber	1,023	558	$57,019,437	$10,759,384	$10,620
Spray Dry Absorbers	1,023	921	$51,538,353	$10,405,618	$11,298
Dry Sorbent Injection	1,023	819	$20,682,000	$6,136,043	$7,495
Capital Recovery Factor = 0.0996 (5.5% interest rate for a 15 year equipment life)					

The Department's economic analysis indicates the level of SO_2 reduction justifies the use of dry sorbent injection as BACT for the coal-fired boilers located in the Serious PM-2.5 nonattainment area.

Step 5 - Selection of SO_2 BACT for the Industrial Coal-Fired Boilers

The Department's finding is that BACT for SO_2 emissions from the coal-fired boilers is as follows:

(a) SO_2 emissions from EUs 4 through 7 shall be controlled by operating and maintaining dry sorbent injection at all times the units are in operation;

(b) SO_2 emissions from EUs 4 through 7 shall not exceed 0.10 lb/MMBtu[11] averaged over a 3-hour period;

(c) SO_2 emissions from EUs 4 through 7 shall be controlled by burning low sulfur coal (0.2% S by weight) at all times the units are in operation; and

(d) Initial compliance with the SO_2 emission rate for the coal-fired boilers will be demonstrated by conducting a performance test to obtain an emission rate.

Table 4-4 lists the proposed SO_2 BACT determination for this facility along with those for other coal-fired boilers in the Serious PM-2.5 nonattainment area.

Table 4-4. Comparison of SO_2 BACT for Coal-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	6 Coal-Fired Boilers	1380 MMBtu/hr (combined)	0.10 lb/MMBtu	Dry Sorbent Injection Limited Operation Low Sulfur Coal
UAF	Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.10 lb/MMBtu	Limestone Injection Dry Sorbent Injection Low Sulfur Coal
Chena	4 Coal-Fired Boilers	497 MMBtu/hr (combined)	0.10 lb/MMBtu[11]	Dry Sorbent Injection Low Sulfur Coal

[11] BACT limit selected after evaluating existing emission limits in the RBLC database for coal-fired boilers, taking into account previous source test data from the Chena Power Plant and actual emissions data from other sources employing similar types of controls, using site specific vendor quotes provided by Stanley Consultants, and in-line with EPA's pollution control Fact Sheets while keeping in mind that BACT limits must be achievable at all times.

5. BACT DETERMINATION SUMMARY

Table 5-1. Proposed NOx BACT Limits

EU ID	Description	Rating/Size	Proposed BACT Limit	Proposed BACT Control
4	Chena 1 Coal Fired Boiler	76 MMBtu/hr	0.05 lb/ MMBtu	Selective Catalytic Reduction
5	Chena 2 Coal Fired Boiler	76 MMBtu/hr		
6	Chena 3 Coal Fired Boiler	76 MMBtu/hr		
7	Chena 5 Coal Fired Boiler	269 MMBtu/hr		

Table 5-2. Proposed SO_2 BACT Limits

EU ID	Description	Rating/Size	Proposed BACT Limit	Proposed BACT Control
4	Chena 1 Coal Fired Boiler	76 MMBtu/hr	0.10 lb/MMBtu	Dry Sorbent Injection Low Sulfur Coal
5	Chena 2 Coal Fired Boiler	76 MMBtu/hr		
6	Chena 3 Coal Fired Boiler	76 MMBtu/hr		
7	Chena 5 Coal Fired Boiler	269 MMBtu/hr		

July 26, 2019

c/o Cindy Heil
Division of Air Quality
ADEC
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Subject: Aurora Energy, LLC's (Aurora) Formal Comment to Proposed Regulation Changes Relating to Fine Particulate Matter ($PM_{2.5}$); Including New and Revised Air Quality Controls and State Implementation Plan (SIP).

The DEC released on May 14, 2019 for public review, the Serious Area State Implementation Plan (SIP) for the Fairbanks North Star Borough (FNSB) Fine Particulate ($PM_{2.5}$) Nonattainment Area (NAA). Public comments are due by 5:00 pm on July 26, 2019. Aurora Energy, LLC (Aurora) appreciates the opportunity to comment on the SIP and the collaborative effort with the Alaska Department of Environmental Conservation (ADEC) to provide a means to attain the $PM_{2.5}$ 24-hour standard that is sensitive to the economics of industries and the communities affected.

1 General Comments

Per the Clean Air Act (CAA), the Serious SIP was supposed to be submitted on December 31, 2017 to describe the Best Available Control Measures (BACM) bringing the area into attainment by December 31, 2019. The 2016 $PM_{2.5}$ Implementation rule allows states to request a 5-year extension of the attainment date (i.e., December 31, 2024) as part of the Serious SIP if attainment is not anticipated by December 31, 2019. Within the 5-year attainment date extension request, the state would outline Most Stringent Measures (MSM) to be applied towards bringing the area into attainment by December 31, 2024. However, if a request is not accepted by the EPA and the area does not meet attainment by the Serious Area attainment date (December 31, 2019) then the Clean Air Act is prescriptive and requires a plan to reduce the concentration of $PM_{2.5}$ by five percent annually. A plan is to be submitted one year after the attainment date (i.e., December 31, 2020) with details on how a 5% annual reduction will be achieved. What has been communicated through the Serious SIP draft is that the most expeditious attainment date for the area is 2029.

5% Reduction Plan

Issue: The DEC is required to submit a 5% reduction plan by December 31, 2020 which hasn't been communicated to the community and/or industry.

Request: As soon as practical, communicate the details of the plan to industry and the community.

Background:

The details of a 5% plan, or at least the outline of such a plan should be better communicated with the community. There is a lack of clarity in what measures the plan would propose. The assumption is the 5% plan will be more stringent than what is being proposed within the Serious SIP.

Device Requirements

Issue: DEC is adopting emission rates for solid fuel heating devices and requirements that do not give all devices equal consideration. Installation of coal-fired heating devices are not allowed unless they are a listed device (18 AAC50.079). There are no standards available in the regulations for the determination of a qualifying coal-fired heating device. Certain devices are not given options for installation within the regulation. Non-pellet fueled wood-fired hydronic heaters, although may have EPA certification under Subpart QQQQ, are not allowed to be installed within the nonattainment area per 18 AAC 50.077 (b) & (c).

Request:

- Develop standards to qualify the installation of coal-fired heating units. Suggested standard should be consistent with 18 g/h emission rate for existing units or 0.10 lbs/MMBtu [heat input basis] whichever is greater.
- Allow the installation of non-pellet fueled wood-fired hydronic heaters provided they are EPA certified.

Background:

The DEC is adopting several different emission rates for solid fuel heating devices which does not give all devices an equal consideration. There are EPA standards for wood stoves and hydronic heaters; also alternative standards for cordwood fired hydronic heaters.[1] These standards should be adopted without alteration. Both wood stoves and pellet fired hydronic heaters emission rates in the SIP are consistent with the 40 CFR Part 60, Subpart QQQQ standard for wood heating devices. The standards are set by the EPA and apply to manufacturers of the wood heating devices. Any such device that is approved by the EPA should be allowed in the nonattainment area, this includes outdoor hydronic heaters. Existing residential and smaller commercial coal-fired devices are required to be removed by December of 2024 and new coal-fired devices are prohibited from installation within the nonattainment area.[2] Coal-fired devices currently installed can be subject to an in-use source test to demonstrate the device meets the standard of 18 g/h of total particulate matter. This standard should also be the criteria for new residential and smaller commercial coal-fired devices. The 18 g/h standard is consistent with 0.10 lbs/MMBtu (heat input) emission rate for a unit that is rated at 400,000 Btu/hr. The Titan II auger-fed coal boilers are rated at 440,000 Btu/hr (heat output) and have undergone testing through OMNI Test Labs; the same lab that derived emission rates for the DEC which are being used in the nonattainment area SIPs. The OMNI test conducted in 2011 demonstrated that auger-fed coal fired hydronic heaters are extremely efficient. Ranking among the lowest emission rates for units tested. Emission rates of auger-fed coal-fired hydronic heaters (0.027g/MJ; **0.06 lbs/MMBtu[heat output basis]**) were consistent with EPA Certified Woodstoves (0.041 g/MJ; **0.10 lbs/MMBtu [heat output basis]**).[3] The DEC is aware that more efficient heating is better for the nonattainment area situation regardless of heating device. Acceptable standards for the installation of coal-fired units should be included within the proposed regulations. There should not only be a standard for the existing units referenced in the regulations but also an achievable emission

[1] Federal Register, Vol. 80, No.50, Monday, March 16, 2015. Pg. 13672.
[2] Section 7.7.5.1.2 "Device Requirements – wood-fired and coal-fired standards", Draft Serious SIP.
[3] OMNI-Test Laboratories, Inc. 2011. Measurement of Space-Heating Emissions. Prepared for FNSB. Retrieved from https://cleanairfairbanks.files.wordpress.com/2012/02/omni-space-heating-study-fairbanks-draft-report-rev-4.pdf

rate and standards for new coal-fired units. While there are provisions for the department's approval contingency, it does not provide a target emission rate for respective devices and fuels that are not EPA certified.

Operational Requirements

Issue: The regulation isn't clear as to whether testing can be done with retrofit control devices on non-qualifying solid fuel heating devices to demonstrate qualifying emission rates. Retrofit control devices can reduce pollution emissions significantly. Use of the devices in the nonattainment area should be incentivized.

Request:

- Clarify within the regulations that emissions testing with retrofit controls can be used to qualify the emissions from solid fuel burning devices.
- The use of retrofit control devices, provided significant reductions in emissions were demonstrated, should be incentivized through an exemption for the use of the solid-fuel heating device with retrofit controls during curtailment periods.
- Suggest a lower emission standard which would qualify the use of solid fuel burning devices during curtailment periods.

Background:

The DEC is imposing curtailments for non-exempt devices during emergency episodes. Ideally, if studies associated with retrofit control devices were to demonstrate significant reductions in pollutant emissions, it would seem appropriate to establish emission rates (i.e., 0.10 lbs/MMBtu or less) and allow for the operation of certain devices that have retrofit controls without curtailment during episodes.

Small Area Sources

Issue: Coffee roasters are required to put emission controls on their processes and small area sources are asked to submit information.

Request:

- Remove the provision requiring coffee roasters to have emission controls.
- Establish a significant level for small area sources similar to major source requirements. That is, require emission controls only if the sources are emitting greater than 70 tpy of the nonattainment pollutant or its precursor and are demonstrated as being significant contributors to the nonattainment area.

Background: The department is considering pollution control devices on small area sources, namely coffee roasters. The application of pollution control is requested even though there are no regulations governing coffee roasting as a source of pollution nor is there any justification indicating that coffee roasting has some significant impact on the fine particulate concentration in the area. Under the Clean Air Act and 2016 $PM_{2.5}$ implementation rule, major sources which emit greater than 70 tons per year of fine particulate matter or its precursors have the ability to show insignificance to the area problem through precursor demonstrations and can be exempt from the application of BACT. Not to mention, if a major source curtails their emissions to less than 70 tons per year, the source doesn't have to participate in any control technology assessment or application. Unless there is some reason to believe that 'coffee roasting' by individual roasters are emitting more than 70 tons of $PM_{2.5}$ through their process, then there is no justification for applying control technologies on those sources. The state is currently asking for information from other small area sources, such as charbroilers, incinerators, and waste oil burners. Industrial activities like incinerators and waste oil burners are subject to the state regulations. If the activity is an insignificant unit, or insignificant on an emission rate basis, category basis, or size and production rate basis as described in the state regulations under 18 AAC 50.326 (d) – (g) or the activity is not required to apply for a Construction Permits under 18 AAC 50.302, there should be no requirement for the small commercial activities unless it is known that they are contributing significantly to the problem. Suggested significance should be defined as the impact of the source to $PM_{2.5}$ concentration within the nonattainment area (i.e., 1.5 $\mu g/m^3$) consistent with the 2019 $PM_{2.5}$ precursor demonstration guidance.

2 Best Available Control Technology

The proposed SIP considers BACT for the major sources; however, authorization of the BACT determination is not finalized through the EPA. With an impending date to install BACT four years from the date of reclassification (i.e., June 9, 2021), there doesn't seem to be time for any technological changes to the community of major sources. Although the state is trying to accommodate the deadline for BACT implementation through creative agreements (e.g., Fort Wainwright), the DEC alternatively could provide justification that the implementation of BACT is both technologically and economically infeasible at this time. This option is available to the state through 40 CFR 51.1010 (3). The economically infeasible consideration is discussed later within these comments, however, a technologic infeasibility case could be considered due to the impending deadlines and the actual time it would take to design, build and implement SO_2-BACT for any facility. A cleaner approach to major source BACT would be to determine that SO_2-BACT for the community of major sources is not economically feasible. If that approach is accepted by the EPA, no further consideration would be necessary for BACT.

The ADEC has provided a BACT analysis for the Chena Power Plant (CPP) and other major sources within the nonattainment area. A top-down approach was used for the FNSB stationary sources. Aurora is providing additional information to better characterize the CPP within the context of a BACT analysis. Aurora is providing an updated emission rate, justification for technically infeasible controls for NOx, and updated capital cost for Dry Sorbent Injection (DSI). Lastly, Aurora is providing a justification for the use of a 0.25% coal-sulfur content as opposed to the 0.2% coal-sulfur content proposed by the DEC in the Serious SIP.

SO_2 and NOx emission rate

Issue: The current emission rates used by ADEC within the SIP for Aurora are not representative.

Request: Update the SIP to reflect the most current emission rates of 0.131 lbs-SO_2/MMBtu and 0.359 lbs-NOx/MMBtu as demonstrated by the source test conducted in July of 2019

Background:

Aurora's current emission rates for SO_2 and NOx referenced by the ADEC for the purposes of BACT and probably the emission inventory within this draft SIP are 0.472 lbs-SO_2/MMBtu and 0.437 lbs-NOx/MMBtu. According to the DEC, these emission rates are taken from a 2011 source test; however, those emission rates are inconsistent with the emission rates associated with the 2011 source test which are 0.398 lbs-SO_2/MMBtu and 0.371 lbs-NOx/MMBtu (See Table 1). In October 2018, Aurora conducted a source test to update the SO_2 and NOx emission rates for the CPP. The emission rates derived were 0.258 lbs-SO_2/MMBtu and 0.346 lbs-NOx/MMBtu. This test was invalidated by the DEC.

Table 1: SO_2 and NOx emission rate from November 11, 2019 source testing

Pollutant	Concentration	Conversion Factor	Cd	Fd	O2 %	Emission Rate
Units	(ppm)		(lb/scf)	(scf/MMBtu)	(%)	(lbs/MMBtu)
Sulfur Dioxide	134.3	1.66E-07	7.5E-06	9739	9.5	0.398
Nitrogen Oxide	174.0	1.194E-07	2.1E-05	9739	9.5	0.371

Subsequently, a new source test was conducted with the intent of using the information within the Serious SIP for the BACT analyses, emission inventory, and modeling. Aurora has coordinated with the DEC in order to have a representative source test to better characterize the emissions from the facility. The source test was performed on July 12, 2019 and evaluated SO_2 and NOx emissions while using representative coal. The three year average coal-sulfur content was evaluated for the period July 1, 2016 through June 30, 2019 to determine the representative coal-sulfur content. The coal-sulfur content mean was 0.12%. The source test plan was approved by the department. Representatives from the department were on-site to verify the source test, the coal feed rate, and used the department's portable monitor to measure SO_2, NOx, and other constituents during the source test.

Although the results indicated within this document are preliminary, once the source test report is finalized, it will be submitted to the DEC for approval. As mentioned, the intent of the source test is to better characterize the emissions from the CPP to use in applications within the Serious SIP like the BACT analysis, emission inventory, and modeling. The new emission rate in lbs/MMBtu of the respective pollutants are 0.131 lbs-SO_2/MMBtu and 0.359 lbs-NOx/MMBtu based on EPA Method 19 and are listed in Table 2 below:

Table 2: SO_2 and NOx emission rate from July 12, 2019 source testing

Pollutant	Concentration	Conversion Factor	Cd	Fd	O2 %	Emission Rate
Units	(ppm)		(lb/scf)	(scf/MMBtu)	(%)	(lbs/MMBtu)
Sulfur Dioxide	45	1.66E-07	7.5E-06	9780	9.2	0.131
Nitrogen Oxide	172	1.194E-07	2.1E-05	9780	9.2	0.359

Provided for reference are the emission rates derived for the CPP during the October 27, 2018 source test (See Table 3). This emission rate was used in the Emission Inventory for 2018 from the facility. The test was invalidated due to a lack of representation by the DEC at the source test. The source test utilized EPA methods and an independent 3rd party source testing company to evaluate the flue gas.

Table 3: SO_2 and NOx emission rate from October 27, 2018 source testing

Pollutant	Concentration	Conversion Factor	Cd	Fd	O2 %	Emission Rate
Units	(ppm)		(lb/scf)	(scf/MMBtu)	(%)	(lbs/MMBtu)
Sulfur Dioxide	89.1	1.66E-07	1.5E-06	9776	9.2	0.258
Nitrogen Oxide	166.2	1.194E-07	2.0E-05	9776	9.2	0.346

Technically Infeasible Pollution Control Option

Issue: Selective Catalytic Reduction is not technically feasible at the Chena Power Plant.

Request: Reflect that SCR is not technically feasible within the BACT analysis for the Chena Power Plant.

Background: Based on an engineering study conducted by Stanley Consultants, SCR was determined technically infeasible for reduction of NOx emissions from the industrial coal-fired boilers at the Chena Power Plant.[4] The optimal location of an SCR would be downstream of the baghouse on the common stack. This arrangement would provide for a constant operating gas temperature, reduces issues associated with fouling on the catalyst and locating the SCR downstream of the catalyst would prevent poisoning by the presence of ammonium sulfates created with the injection of ammonia in the flue gas. However, the temperatures of the flue gas after the baghouse are less than adequate. A minimum temperature of 350°F is required for the SCR catalysts to function correctly. The flue gas temperature after the baghouse is approximately 310°F.

Updated Capital Cost for DSI

Issue: Capital cost for DSI as provided to the DEC was determined to be $20,682,000.

Request: Use the capital cost of $20,604,000 for DSI in the BACT analysis to determine a cost effectiveness value.

Background: A refined and final opinion of probable cost is being provided for the CPP DSI which is $20,604,000.[5]

BACT Cost Effectiveness Calculations

Issue: The DEC BACT cost effectiveness values in the draft SIP for the Chena Power Plant are not representative.

Request: Change the section to reflect representative cost effectiveness values based on the representative emission rates outlined below.

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[4] Stanley Consultants, Inc. (2019, April). "Best Available Control Technology Analysis – Independent Assessment of Technical Feasibility and Capital Cost". Aurora Energy, LLC.
[5]Ibid.

Background:

BACT cost effectiveness calculations were done by the DEC using established cost estimating procedures. The procedures require that inputs are adjusted to reflect the conditions of the facility assessed. Some of the key inputs identified by the DEC are as follows: the emission rate for SO_2 and NOx were 0.472 lbs-SO_2/MMBtu and 0.437 lbs-NOx/MMBtu, a retrofit factor of 1.5 was used for a difficult retrofit, an interest rate of 5.5%, and equipment life for NOx and SO_2 controls were 20 and 15 years respectively. Using the DEC inputs for wet scrubbers and SDA technologies, the cost effectiveness value and capital costs output are not consistent with the text within the draft SIP. DEC calculated the cost effectiveness for the installation of wet scrubbers and SDA to be $10,620/ton and $11,298/ton. When the DEC inputs were used within the spreadsheets, the cost effectiveness values for the installation of wet scrubbers and SDA were $14,572/ton and $15,726/ton (See Table 4 - values in parentheses) respectively. However, when the emission rate was updated in the spreadsheets to the representative emission rate from the July 12, 2019 source test (0.131 lbs-SO_2/MMBtu), the cost effectiveness value increased to $49,585/ton for wet scrubbers and $53,909/ton for SDA. Using the DEC's spreadsheets for DSI cost effectiveness, Aurora adjusted the capital cost of DSI from $20,682,000 to $20,604,000 based on refined opinion of probable cost and used the updated emission rates referenced in Table 2. The cost effectiveness value for DSI increased from $7,495/ton to $18,007/ton (Table 4).

Table 4: Updated Cost Effectiveness Value based on SO2 and NOx Representative Source Test (7/12/19)

Technology	DEC Cost Effectiveness Value (cost/ton removed)	Capital Cost ($)	Updated Cost Effectiveness Value (cost/ton removed)	Adjusted Capital Cost ($)
Selective Catalytic Reduction	$4,023/ton		Not Technically Feasible	
Selective Non-Catalytic Reduction	$2,227/ton		$2,587/ton	
Wet Scrubbers	$10,620/ton ($14,572/ton)	$57,019,437 ($87,152,852)	$49,585/ton	$82,323,012
Spray Dry Absorbers	$11,298/ton ($15,726/ton)	$51,019,437 ($81,280,628)	$53,909/ton	$77,293,649
Dry Sorbent Injection	$7,495/ton	$20,682,000	$18,007/ton	$20,604,000

Note: Values in parentheses are the output from the cost development methodology used by the DEC with inputs suggested within Section 7.7.8 "Control Strategies" of the draft Serious SIP.

Based on the adjusted values, it is not cost effective to install BACT for SO_2 at the Chena Power Plant.

Sulfur Content of Coal

Issue: Proposed BACT for coal-sulfur content of 0.2% will cut off access to tens of millions of tons of coal for UCM as well as pose a potential threat of fuel supply interruption for the coal fired power plants.

Request: Adopt a new standard of 0.25% based on semi-annual weighted averages of coal-sulfur content in shipments of coal within semi-annual periods corresponding to Facility Operating Report reporting periods.

Background:

The ADEC has proposed that Best Available Control Technology (BACT) for coal burning facilities in the nonattainment area is a coal-sulfur limit of 0.2% sulfur by weight. Usibelli Coal Mine (UCM) is the only source of commercial coal available to the coal-fired facilities within the Fairbanks North Star Borough fine particulate nonattainment area. The mine has limited ability to affect the sulfur content in the coal. There isn't a coal washing or segregating facility associated with UCM which could ensure a consistent coal-sulfur concentration. Current practice for providing low-sulfur coal to customers is identifying sulfur content of the resource through drilling and sampling efforts. However, no matter how much sampling is done, the ability to characterize the sulfur content of the coal actually mined is limited.

Within the millions of tons of coal resources available to UCM, there is a significant amount of coal with higher sulfur content than 0.2%; in fact, any limit proposed to the coal sulfur content is effectively cutting off access to tens of millions of tons of coal resources. As such, AE proposes that the coal-sulfur limit be lowered to 0.25% on an as received basis (wet) as opposed to 0.2% as proposed by ADEC. The increase in coal-sulfur content will help with coal accessibility and availability over the next decade and still provides ADEC with a 37.5% reduction in the potential to emit based from the current limit of 0.4%.

The state was silent on how the measure was to be reported or considered within a regulatory context. The ADEC's standard permit condition for coal fired boilers (Standard Condition XIII) requires that the permittee report sulfur content of each shipment of fuel with the semi-annual Facility Operating Reports. UCM currently provides semi-annual reports to all customers which includes sulfur content of each shipment of coal along with the weighted average coal-sulfur content for the six-month period coinciding with the operating reports' reporting period. UCM and Aurora propose that the standard operating permit condition remain the same and that facilities continue to provide the state with the sulfur content of each shipment of fuel; in addition, the weighted average coal-sulfur content of the shipments received by the facility during the reporting period would be referenced in the operating report.

3 SO_2 Precursor Analysis

Issue: There are inconsistencies in DEC's information with respect to SO_2. The major source contribution to sulfur-based $PM_{2.5}$ from major source SO_2 ground level concentrations have increased from 2008; even though point source SO_2 emissions have decreased while SO_2 emissions from heating oil and total SO_2 emissions have increased.

Requests:

- Change referenced $PM_{2.5}$ significance threshold from 1.3 μg/m^3 to 1.5 μg/m^3 based on the final EPA $PM_{2.5}$ Precursor Demonstration Guidelines (2019).
- Revisit SO_2 Analysis after applying representative emission rates for the Chena Power Plant for SO_2 and NOx (0.131 lbs-SO_2/MMBtu and 0.359 lbs-NOx/MMBtu).
- Clarify discrepancy between the 2008 CALPUFF model output reflecting 22% contribution to ground-level SO_2 from major sources and current CMAQ evaluation reflecting 39% SO_2 contribution from major sources.
- Reconsider SO_2 Precursor Demonstration for Major Source impact using a sensitivity analysis to determine significance.

Background:

The DEC completed an SO_2 Analysis using the 2019 projected baseline inventory and run through CMAQ model. All of the SO_2 emissions were removed from the point source sector in a knock out model run. The meteorology used was from 2008, which is consistent for all of the model runs. The SO_2 from major stationary sources were found to contribute significantly to the $PM_{2.5}$ concentrations at the State

Office Building (SOB) [1.79 µg/m^3] and at the monitoring site adjacent to the Borough building (NCORE) [1.70 µg/m^3] in Fairbanks. The impact of SO_2 from major sources was also determined to be significant at all four monitoring sites (SOB, NCORE, Hurst Road, and NPE) when an alternative approach to estimating the design value contribution from major stationary sources was applied [respectively: 2.66 µg/m^3,2.53 µg/m^3, 1.55 µg/m^3, 1.35 µg/m^3]. The DEC referenced an insignificance threshold of 1.3 µg/m^3 to determine significance; however, final PM2.5 Precursor Demonstration Guidance has changed that threshold to 1.5 µg/m^3.[6]

Regardless of the change in significance value, three of the sites (SOB, NCOR, and Hurst Road) would still be considered significant when the alternative approach to estimating the design value contribution is considered. If the impact of major source SO_2 emissions on $PM_{2.5}$ exceeds 1.5 µg/m^3, then a sensitivity-based analysis may be conducted to show that a reduction of SO_2 emissions in the range of 30 - 70% would only have an insignificant impact on lowering $PM_{2.5}$ concentration. Aurora demonstrated that there was justification to pursue a precursor demonstration using information provided in the moderate area SIP. The major source contribution to $PM_{2.5}$ from SO_2 was determined to be 1.98 µg/m^3 of water-bound ammonium sulfate. The conclusion of the exercise was that a 70% reduction in SO_2 would demonstrate insignificance of the SO_2 contribution from major sources on $PM_{2.5}$ concentration [i.e., 1.45 µg/m^3].[7] It is Aurora's opinion that a successful precursor demonstration may still be possible using a 50% reduction even considering DEC's alternative approach to estimating design value contributions from major source SO_2. However, the DEC has indicated due to sulfate model performance uncertainty and significance of the major source contribution from SO_2 emissions, there is not enough justification to pursue the demonstration.

Aurora has a few concerns with the SO_2 analysis. Probably the most significant is that the contribution of SO_2 at the SOB monitor from major sources increased to 39% from 22% as described in the Moderate Area SIP (2014). CALPUFF modeling showed that the point source SO_2 contribution to the SOB monitoring site was 22% for an episode in 2008. The emission inventory for 2008, 2013, and the projected 2019 show a decreasing trend in SO_2 emissions for point sources (See Table 5). The ratio between SO_2 emissions from oil heating and point sources (Oil Heating SO_2/Point Source SO_2) increases from 2008 to 2019 (projected) from 0.46 to 0.51 for the planning inventory in the NAA (Table 5). This would suggest that the amount of SO_2 emissions from oil increased in relation to the amount of SO_2 emissions from point sources. That fact is counterintuitive to the modeling outputs which indicates SO_2 contribution from point sources increased 18% from 2008 to 2019 at the SOB.

The total SO_2 emissions per day in 2019 is about two times what it was in 2008 and 2013 (See Table 5). The difference is attributed to an increase in Non-Road Mobile sources; in fact, a change in jet fuel between 2013 and 2019 is referenced as the cause of the increase.[8] It would seem that the likelihood for an increased impact at the monitors from SO_2 should have come from this change as opposed to the point sources.

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[6] https://www.epa.gov/sites/production/files/2019-05/documents/transmittal_memo_and_pm25_precursor_demo_guidance_5_30_19.pdf
[7] Memo. Ramboll. "Summary of issues related to SO_2 precursor demonstation for Fairbanks". 2018.
[8] Section 7.6.3.2 "2019 Projected Baseline Emission Inventory", Draft Serious SIP.

Table 5: Baseline Episode Average Daily SO_2 Emissions (tons/day) by Source Sector

Source Sector	Modeling Inventory Grid 3 Domain			Planning Inventory NA Area		
	2008	2013	2019 (projected)	2008	2013	2019 (projected)
Point Sources	8.380	7.40	7.32	8.167	7.22	7.13
Area, Space Heating, Oil	4.121	3.68	3.90	3.719	3.42	3.61
Total	12.875	12.65	25.58	12.155	11.92	22.36

Note: 2008 data from Moderate Area SIP (Table 5.6-7); 2013 & 2019 data from draft SIP, Tables 7.6-10 & 7.6-12, respectively.

The increase in point source contribution of SO_2 at the monitoring sites is, therefore, perplexing. Aurora also believes that point source emission of SO_2 in the inventories may be inflated due to the emission factor used to determine Aurora's SO2 emissions (and NOx emissions). Within the BACT section of the draft SIP, an emission factor for SO_2 was referenced as being 0.472 lbs-SO_2/MMBtu. A recent source test conducted on July 12, 2019 at the Chena Power Plant was arranged specifically to better characterize the emission rates for SO_2 and NOx from the plant. The test plan was approved by the state with additional scrutiny due to its intended use. The test demonstrated an emission factor of 0.131 lbs-SO_2/MMBtu. This value is a preliminary emission rate. The final report will be provided to the DEC so that, when approved, the new emission rate would be updated in the state's databases and worksheets for the final submittal of the Serious Area SIP to the EPA.

Aurora would also like the state to clarify the discrepancy between the 2008 CALPUFF modeling, which showed a major source SO_2 contribution of 22% at the SOB monitoring site, in relation to the recent evaluation referenced under the SO_2 Analysis (Section 7.8.12.5) where major source SO_2 contribution to the SOB was 39%. Aurora would like the DEC to reconsider an SO_2 precursor demonstration for major source contribution to $PM_{2.5}$ concentration. Aurora believes a successful demonstration could be done using the provisions of a sensitivity analysis as described in the 2019 $PM_{2.5}$ Precursor Demonstration Guidance.

4 Major Source Economic Infeasibility Justification

Issue: The DEC has the option to demonstrate the economic infeasibility of SO_2 BACT for major sources within the nonattainment area under 40 CFR 51.1010 (3) based on cost effectiveness. The most cost effective value for operating BACT controls on the community of major sources to remove 1 $\mu g/m^3$ of $PM_{2.5}$ is $9,794,799 per year [See Table 7b].

Request:

- Define cost effectiveness as cost per 1 $\mu g/m^3$ of $PM_{2.5}$ for this exercise.
- Derive a cost per ton removed for each major source in the nonattainment area by adjusting operational load to represent actual SO_2 emissions in the spreadsheets for each facility provided within the appendices of the "Control Strategies" section of the draft serious SIP.
- Evaluate the cumulative annualized cost incurred by the community of major sources within the nonattainment area based on potential tons removed from implementing SO_2 BACT using actual emissions (instead of PTE).

- Correlate annualized cost of SO_2 BACT controls with results from the SO_2 Analysis section of the draft SIP (Section 7.8.12.5) to derive a cost per µg/m^3 mitigated from applying SO_2 control technologies.

Background:

Major stationary sources are a subgroup of emission sources that are given special consideration under nonattainment area provisions. Point sources with emissions greater than 70 tons per year of $PM_{2.5}$ or any individual precursor (NOx, SO_2, NH_3, VOCs) are evaluated for appropriate control. NOx and SO_2 were addressed on an emission unit specific basis in DEC's Best Available Control Technologies (BACT) determinations. The DEC's evaluation considered technical feasibility and estimates of emissions reductions to meet a defined emission limit. Operations at the facility's potentials to emit is used for the purpose of identifying a cost effectiveness for each technology in cost per ton removed.

The BACT analyses evaluate pollution control independent of the nonattainment area problem; it is simply triggered as a condition of an area defined as being in serious nonattainment of a pollutant standard. As described in the 2016 $PM_{2.5}$ Implementation Rule, the state can provide either a technologic or an economic infeasibility demonstration for control measures.[9] The argument must illustrate it is not technologically or economically feasible to implement the control measure by the end of the tenth calendar year (i.e., December 31, 2019 for the FNSB NAA) following the effective date of the designation of the area. Aurora believes that there is enough evidence to substantiate that SO_2 controls on the community of major sources is economically infeasible.

<u>Economic Infeasibility Justification</u>

The DEC has determined BACT is comprised of sulfur controls for major stationary sources. The DEC has also determined that sulfur controls are economically infeasible for one major source, silent on infeasibility for another, and partially economically infeasible for a couple of major sources within the NAA.[10] Per regulation, DEC has the authority to demonstrate that any measure identified is economically infeasible.[11] It is within the DEC's authority to determine that BACT for sulfur control is economically infeasible for the community of major sources in the NAA based on cost effectiveness.[12] If cost effectiveness is defined as cost per µg/m^3 removed, there is a clear justification to eliminate sulfur control measures from the community of major sources. The most cost effective value for operating BACT controls on the community of major sources to remove 1 µg/m^3 of $PM_{2.5}$ is $9,794,799 per year [See Table 7b].

<u>Annualized Cost of BACT Implementation</u>

The DEC derived cost effectiveness value in cost per ton removed is established through the implementation of the BACT analysis. The DEC preferred BACT controls and cost effectiveness value are referenced in Section 7.7.8 of the SIP.[13] Dry Sorbent Injection (DSI) is selected for the coal fired boilers with an 80% reduction in SO_2 and ULSD is suggested for GVEA's North Pole Plant and Zehnder

[9] 40 CFR 51.1010 (3)
[10] Section 7.7.8 of the draft Serious SIP
[11] 40 CFR 51.1010 (3)
[12] 40 CFR 51.1010 (3)(ii)
[13] Appendix III.D.7.07 Control Strategies: https://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip/

Facility with a 99.7% removal rate for SO_2. Based on the Potential to Emit (PTE) of each facility, the state derives a cost effectiveness value for the sources.

Annualized cost to implement BACT for the community of major sources are based on operating scenarios for both PTE and actual emissions (2013) [14] from the facilities. The results are illustrated in Table 6a and 6b. The cost effectiveness value (cost/ton removed) is multiplied by the amount of pollution removed (tons) to derive an annual cost for BACT for each facility. The total annualized cost is the sum of the cumulative annual operating cost for the controls on all the major sources in the NAA. The annualized costs do not include the cost of fuel switching for smaller diesel engines, backup generators and boilers that are found on the campuses of certain facilities (e.g., UAF, FWA). The total annualized BACT implementation cost to operate at the PTEs is $49,296,062; annualized cost considering actual emissions is $20,843,332 (See Tables below).

Table 6a: BACT Annualized Costs Based on Potential To Emit

Facility	BACT (SO_2 Control)	SO_2 Reduction	SO_2 Emissions PTE[3]	SO_2 Reduction[3]	Cost/ton removed [2,3]	Annualized Cost
Units		(%)	(tpy)	(tpy)	($)	($)
Chena Power Plant	DSI	80	1,004.0	803.0	$ 7,495	$ 6,018,485
FWA	DSI	80	1,168.5	934.8	$ 10,329	$ 9,655,331
NPP-EU1	ULSD	99.7	1,486.4	1,482.0	$ 9,139	$ 13,543,998
NPP-EU2	ULSD	99.7	1,356.1	1,352.0	$ 9,233	$ 12,483,016
UAF	DSI	80	242.5	194.0	$ 11,578	$ 2,246,132
Zender	ULSD	99.7	598.6	597.0	$ 8,960	$ 5,349,120
Notes: See Below.					Total Annualized Cost	$ 49,296,082

Table 6b: BACT Annualized Costs Based on Actual Emissions

Facility	BACT (SO_2 Control)	SO_2 Reduction	SO_2 Emissions (Actual)[1,3]	SO_2 Reduction	Cost/ton removed[4]	Annualized Cost
Units		(%)	(tpy)	(tpy)	($)	($)
Chena Power Plant	DSI	80	711.8	569.4	$ 8,960	$ 5,101,824
FWA	DSI	80	766.5	613.2	$ 11,235	$ 6,889,302
NPP-EU1	ULSD	99.7	142.3	141.9	$ 12,169	$ 1,726,454
NPP-EU2	ULSD	99.7	422.3	421.0	$ 9,453	$ 3,980,026
UAF	DSI	80	219.0	175.2	$ 11,578	$ 2,028,466
Zender	ULSD	99.7	73.0	72.8	$ 15,351	$ 1,117,261
Notes:					Total Annualized Cost	$ 20,843,332

1 - Table 7.6-9 "2013 SO2 Episodic vs. Annual Average Point Source Emissions (tons/day)"
2 - Sectoin 7.7.8 of SIP
3 - BACT Spreadsheets (May 2019) in SIP for Listed Facilities; adjusted AE emission factor of 0.472 lbs-SO2/MMBtu referenced in BACT Section of SIP.
4 - Cost/ton removed after adjusting operational load in BACT Spreadsheets (May 2019) to reflect actual emissions; AE emission factor of 0.472 lbs-SO_2/MMBtu

Major Source SO_2 Control Cost Effectiveness: Cost per $\mu g/m^3$ $PM_{2.5}$ Removed

The DEC provided an SO_2 analysis using the 2019 projected baseline inventory. [15] The DEC determined that major stationary sources were found to contribute significantly to $PM_{2.5}$ concentrations at the State Office Building (SOB) and the monitor adjacent to the Borough building (NCORE) in downtown Fairbanks. The impact at the monitors were 1.79 $\mu g/m^3$ and 1.70 $\mu g/m^3$ respectively.[16] The impact at the Hurst Road and North Pole Elementary (NPE) monitors were 0.04 $\mu g/m^3$ and 0.10 $\mu g/m^3$ respectively.

Assuming that an 80% removal of the point source emissions of SO_2 would translate to an 80% reduction to the impact from major sources of sulfur-based $PM_{2.5}$ at the monitors, the amount of $PM_{2.5}$ reduced at the SOB, NCORE, Hurst Road, and NPE monitors would be 1.43 $\mu g/m^3$, 1.36 $\mu g/m^3$, 0.03 $\mu g/m^3$, and 0.08 $\mu g/m^3$ respectively. Based on the total annualized cost for BACT controls using actual emissions ($20,843,332) the cost effectiveness value in cost per $\mu g/m^3$ of $PM_{2.5}$ removed is at the best, $14,555,400 per $\mu g/m^3$ removed and at the worst $651,354,137 per $\mu g/m^3$ removed (Table 7a). If the alternative

[14] Table 7.6-9 "2013 SO2 Episodic vs. Annual Average Point Source Emission (tons/day)"[Draft Serious SIP]ADEC
[15] Section 7.8.12.5 of the draft Serious SIP
[16] Table 7.8-26. "Design value contribution from major stationary source SO_2".Draft Serious SIP.

approach to the SO_2 design value contribution from major sources is considered then the cost effectiveness at best is \$9,794,799 per µg/m^3 and at worst is \$19,299,382 per µg/m^3 (Table 7b).

Ironically, the cost per µg/m^3 removed is less at the SOB and NCORE sites where the projected design value is in compliance with the standard. The projected design value provided by the DEC for 2019 meet attainment at the SOB and NCORE sites which are of 29.72 µg/m^3 and 29.01 µg/m^3 respectively[17]; the attainment standard is 35 µg/m^3. The 2019 design values at the Hurst Road and NPE monitors were 104.81 µg/m^3 and 36.48 µg/m^3, both clearly above the attainment standard of 35 µg/m^3. The impact from the major sources is less significant at the sites where the 2019 projected design value violates the standard.

Table 7a: Cost Effectiveness Based on Design Value Contribution SO_2 from Major Stationary Sources

Site	Design Value Base Year 2013[1]	Projeced Design Value Year 2019[1]	Major Source Sulfur-Based Particulate Contribution[2]	BACT Reduction (80% of Direct Emissions)	BACT Reduction / Design Value 2019	Annualized BACT Cost per ug/m^3 removed
Units	(ug/m^3)	(ug/m^3)	(ug/m^3)	(ug/m^3)	(%)	(\$)
State Office Building (SOB)	38.93	29.72	1.79	1.43	4.8%	\$ 14,555,400
Fairbanks Borough Building (N	37.96	29.01	1.70	1.36	4.7%	\$ 15,325,980
Hurst Road	131.63	104.81	0.04	0.03	0.0%	\$ 651,354,137
North Pole Elementary (NPE)	45.3	36.48	0.10	0.08	0.2%	\$ 260,541,655

Notes:
1 - Table 7.8-29 of Draft Serious SIP
2 - Table 7.8-26 of Draft Serious SIP

Table 7b: Cost Effectiveness Based on Alternative Approach to Design Value Contribution SO_2 from Major Stationary Sources

Site	Design Value Base Year 2013[1]	Projeced Design Value Year 2019[1]	Major Source Sulfur-Based Particulate Contribution[2]	BACT Reduction (80% of Direct Emissions)	BACT Reduction/Design Value 2019 x 100	Annualized BACT Cost per ug/m^3 removed
Units	(ug/m^3)	(ug/m^3)	(ug/m^3)	(ug/m^3)	(%)	(\$)
State Office Building (SOB)	38.93	29.72	2.66	2.13	7.2%	\$ 9,794,799
Fairbanks Borough Building (N	37.96	29.01	2.53	2.02	7.0%	\$ 10,298,089
Hurst Road	131.63	104.81	1.55	1.24	1.2%	\$ 16,809,139
North Pole Elementary (NPE)	45.3	36.48	1.35	1.08	3.0%	\$ 19,299,382

Notes:
1 - Table 7.8-29 of Draft Serious SIP
2 - Table 7.8-27 of Draft Serious SIP

Fairbanks exceeds the fine particulate matter standard during winter months.[18] Control technology application on major stationary sources is permanent and transcends seasons. BACT for sulfur control on major sources is an annual solution to a wintertime problem. The application of SO_2 BACT is arguably an impractical effort. Where the pollutant concentration is either achieving or almost achieving the standard, the projected impact removed by application of BACT on the major sources is about 7% of the concentration. Since the standard is attained, removing 7% more of sulfur-based $PM_{2.5}$ for costs upward of \$10 million dollars per µg/m^3 seems impractical. There is a mechanism allotted within the 2016 $PM_{2.5}$ Implementation Rule for the DEC to provide a detailed written justification for eliminating, from further consideration, potential control measures for SO_2 on the community of major stationary sources based on cost ineffectiveness.

As such, Aurora supports an economic infeasibility determination for the application of BACT on all major stationary sources within the nonattainment area.

[17] Table 7.8-29. "2019 FDV for Projected Baseline and Control Scenario Calculated against a 2013 Base year".
[18] Section 7.8.6 of the Draft Serious SIP

5 $PM_{2.5}$ Emission Reduction Credits

Issue: Currently there are no provisions for the FNSB NAA within the regulations that establish emission reduction credits.

Request: Include provisions in the Serious SIP for establishing $PM_{2.5}$ emission reduction credits per 40 CFR 51 Appendix S.

Background:

Aurora Energy requests that the SIP include provisions for establishing PM2.5 emission reduction credits, as provided in 40 CFR 51 Appendix S. The SIP should recognize that the most fertile area for establishing further emission reduction credits involves reducing emissions from wood-fired residential heaters – stoves and fireplaces. The approach to accounting for dried wood emissions should consider enhanced wood-moisture reduction through a process such as kiln drying, to levels as low as 15 percent (dry wood basis) beyond the 20 percent levels in the proposed SIP and allow those lower emissions to be applied as emission reduction credits for potential future development within the Non-Attainment Area. The approach also lessens the level of involvement of agency oversight of the individual components of the SIP that are related to residential wood combustion. Residential wood combustion is an ingrained cultural component of life in Fairbanks, and the proposed enhanced drying option is likely to be well supported by members of the community. We urge consideration of this approach that will both clean the air and provide some potential for emissions increases, through offsets developed under this proposal, to further strengthen the economic viability of the Fairbanks North Star Borough community.

6 Conclusion

In summary, there are several elements to the SIP that Aurora is addressing as a part of the public comment. The DEC has an incredible task which is being addressed to the extent possible with the time and resources available. Below are summaries of the key points Aurora addressed within the comments:

- BACT requirement for coal facilities to meet coal-sulfur content of 0.2% is being contested. Auroras requests a modified BACT requirement to 0.25% coal-sulfur (as received) evaluated on a six-month weighted average using UCM analyses for each shipment.
- SO_2 and NOx emission rates being used for Aurora within the SIP are not accurate representation of the facilities emission rates. Suggest using newly established rates derived through representative source testing with representative coal.
- Additional information is provided to support technologic infeasibility of SCR, a change in the capital cost for DSI, and emission rate changes for the determination of cost effectiveness within the context of the BACT analyses.
- Aurora supports an economic infeasibility determination for the community of major sources based on the cost ineffectiveness of sulfur control technology in removing 1 $\mu g/m^3$ of sulfur-based $PM_{2.5}$ from major source SO_2 contribution.
- Aurora requests that the SIP include provisions for establishing $PM_{2.5}$ emission reduction credits, as provided in 40 CFR 51 Appendix S.
- One of the key parts to the future of the nonattainment area is the 5% reduction plan. The elements within this plan, which is anticipated for submittal at the end of 2020, have not been communicated to the community or industry. It is the opinion of Aurora that communication with the community about the elements within the 5% reduction plan is warranted and necessary.

- Solid fuel burning devices are not treated equally within the Serious Area SIP. A proposition for a common emission standard for those units that do not have EPA certification or standard to meet is encouraged. Those units with EPA standards should be allowed to operate within the NAA. Also, inclusion of emission standards and criteria for coal-fired home heating devices within the regulation is encouraged.
- Retrofit control devices should be encouraged for use to meet emission standards as necessary.
- The departments' imposition of control technologies on small sources, such as coffee roasters, is not supported. Major sources are able to take operational limits to reduce emissions to less than 70 tons per year to avoid pollution control. Small commercial sources shouldn't be subject to pollution controls unless there is evidence that their emissions are significant.

Enclosure:

Stanley Consultants, Inc. (2019, April). "Best Available Control Technology Analysis – Independent Assessment of Technical Feasibility and Capital Cost". Aurora Energy, LLC.

Best Available Control Technology Analysis

Independent Assessment of Technical Feasibility and Capital Cost

Chena Power Plant
Aurora Energy, LLC
Fairbanks, Alaska

Final
April 2, 2019

Stanley Consultants INC.
A Stanley Group Company
Engineering, Environmental and Construction Services - Worldwide

April 2, 2019

Mr. David Fish
100 Cushman Street
Suite 210
Fairbanks, AK 99701

Dear Dave:

Stanley Consultants is pleased to provide you with the final version of the Independent Assessment of Technical Feasibility and Capital Cost in support of your Best Available Control Technology Analysis. We greatly appreciate the opportunity to assist Aurora Energy in this effort and we look forward to working with you again soon.

Respectfully submitted,

Stanley Consultants, Inc.

Prepared by Jason Smith

Approved by
John P. Solan

STATE OF ALASKA
49 TH
JOHN P. SOLAN
No. ME14412
4/2/19
REGISTERED PROFESSIONAL ENGINEER

I hereby certify that this engineering document was prepared by me or under my direct personal supervision and that I am a duly licensed Professional Engineer under the laws of the State of Alaska.

My license renewal date is December 31, 2019.
Pages or sheets covered by this seal: Entire Report

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Section 1

Introduction

This report documents the results of an independent engineering assessment of the technical feasibility and probable capital costs for emissions control retrofits at the Chena Power Plant in Fairbanks, Alaska. The report is intended to supplement the information previously provided by Aurora Energy in the Best Available Control Technology (BACT) Analysis Report, including any revisions or addendums thereto. It also incorporates some of the conclusions reached by the Alaska Department of Environmental Conservation (ADEC) in their Preliminary Best Available Control Technology Determination.

Background

The US Environmental Protection Agency (EPA) has recently reclassified portions of the Fairbanks North Star Borough as a Serious PM 2.5 Non-Attainment Area. This reclassification triggers a requirement that all major sources within the non-attainment area perform a BACT analysis for particulate emissions and the emissions of any precursor pollutants. In response to this requirement Aurora Energy submitted the required BACT Analysis to ADEC in March of 2017. An addendum to the report was submitted in December of that year.

After reviewing the data and conclusions presented in the BACT Analysis, ADEC conducted their own analysis and presented the results as a Preliminary BACT Determination in March 2018. The ADEC report documented several conclusions that differed from those presented in the BACT report submitted by Aurora Energy.

Project Scope

Given the disparity in the results of the analyses, Aurora Energy hired Stanley Consultants to review the technical feasibility of control technologies for two specific precursor pollutants; Nitrogen Oxides (NO_x) and Sulfur Oxides (SO_x). In this report these pollutants may also be referred to as Nitrogen Oxide (NO) and Sulfur Dioxide (SO_2) as these are the most common forms of the nitrogen and sulfur pollutants.

Aurora Energy also requested that Stanley Consultants develop a site-specific, third-party estimate of the costs to install and operate technically feasible SO_2 emissions control equipment on the four operating boilers at the Chena Power Plant. This effort will include the development of a capital cost estimate for the identified systems, sorbent consumption rate estimates, and an estimated cost for the purchase and delivery of sorbent to site. Once these costs have been developed, Aurora Energy and their environmental consultants, Environmental Resources Management (ERM), will incorporate the estimated costs into a calculation to determine the cost effectiveness of the emissions control equipment on a basis of Dollars/Ton of SO_2 removed.

Section 2

Discussion of NO_x Control Options

The original BACT Analysis developed by ERM provided a comprehensive review of the various technologies currently available to control NO_x emissions. It also identified if each technology was technically feasible or infeasible based on the specific application at the Chena Plant. The report concluded that the only technically feasible NO_x reduction technologies were Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR). Similar conclusions regarding the technical feasibility were reached by ADEC in the Preliminary BACT determination.

Stanley Consultants has reviewed the information provided in both documents. While we are in general agreement, there are technical limitations relating to the application of SCR and SNCR technology that were not adequately addressed in either document.

Selective Catalytic Reduction

Both the ENR BACT Analysis and the Preliminary BACT Determination correctly determine that SCR technology has been successfully utilized to reduce the emissions of nitrogen oxides on industrial coal fired boilers. Both documents detail the mechanism by which the oxides are removed from the flue gas stream and the both correctly note that the chemical reaction is highly dependent on the flue gas temperature. Neither report, however, mentions the actual flue gas conditions at the Chena Plant, nor do they mention where a SCR is typically located with respect to the boiler outlet and the stack. A flue gas temperature is provided in the ADEC SCR Economic Analysis Spreadsheet (https://dec.alaska.gov/media/7381/chena-scr-economic-analysis-adec.xlsm). This spreadsheet uses a flue gas temperature of 310 °F based on information collected during a 2016 source test at the Chena Plant. This data, however, is only used to calculate the Volumetric Flue Gas Flow Rate. There is no check in the ADEC SCR Economic Analysis spreadsheet to determine if the subject emission source flue gas temperature is within a typical operating temperature range for commercially available catalyst.

Modern SCR systems for industrial boiler applications like the Chena Plant are generally located downstream of the flue gas particulate filter. This position in the flue gas system has several advantages:

- This arrangement allows a constant operating gas temperature throughout the boiler load range.
- Locating the SCR downstream of a baghouse significantly reduces issues associated with ash fouling of the catalyst blocks.
- Locating the SCR downstream of sulfur emissions control equipment will prevent the catalyst from being poisoned by the presence of ammonium sulfates which are formed when ammonia is injected into the flue gas stream in the presence of sulfur.

The Chena Plant currently utilizes a single baghouse to filter particulate from the flue gas streams of all four boilers. The optimal location for any future SCR would therefore be on the common flue gas duct immediately downstream of the existing baghouse.

The boilers at the Chena Plant are currently configured with an integral economizer attached directly to the exhaust flange of each boiler. The purpose of this economizer is to utilize waste heat in the flue gas to preheat water entering the boiler drum. This results in a significant reduction in flue gas temperature across the economizer. The 2016 source test data used by ADEC in their economic analysis indicated that typical full-load flue gas temperatures at the stack was approximately 310 °F. Stanley Consultants provided this information, along with other information relating to the flue gas system configuration, to a systems vendor BACT Process Systems for their review and input. BACT Process Systems was contacted as they had recent experience in the supply and installation of emissions control equipment (including a Dry Sorbent Injection System and SCR) at nearby Eielson Air Force Base (EAFB). The EAFB facility burns the same coal as the Chena plant in boilers of similar design. The response from BACT, based on information collected from one of their current catalyst suppliers, indicated that current SCR catalysts require a minimum of 350 °F to function effectively. This statement was also verified by a second SCR vendor. A representative of Fuel Tech, Inc. indicated that temperatures below 400 °F can significantly increase the required amount of catalyst. The representative also confirmed that the minimum flue gas temperature is between 350 °F and 365 °F. Information provided by both vendors can be found in Appendix A.

Other SCR configurations are utilized to allow the installation of an SCR into an existing flue gas system. The configuration that is most applicable to this scenario would be one that was recently utilized at Eielson Air Force Base in conjunction with the installation of the replacement boilers for Units 5 and 6. The design at Eielson relies on two separate economizers. The first economizer is integral to the boiler and is used to reduce the temperature of the flue gas leaving the boiler to approximately 500 °F. The flue gas is then treated with sodium bicarbonate to reduce sulfur emissions before it passes through the baghouse and the SCR. The second economizer is located after the SCR and is used to reduce the flue gas temperature to approximately 300 to 350 °F. This configuration works well for the Eielson facility because each flue gas system is separate from the other boilers and the equipment (boiler, sorbent injection, baghouse, SCR, and economizers) are in close proximity to each other. This configuration would not be possible at the Chena Plant due to the existing boiler enclosure building and the existing common flue duct tying the boilers together into the baghouse and the large distances between the boilers and the baghouse.

Given the constraints identified above, Stanley Consultants concludes that Selective Catalytic Reduction is not technically feasible at the Chena Plant. This is contrary to the conclusions reached by both ERM and ADEC.

Selective Non-Catalytic Reduction

Stanley Consultants has reviewed the information relating to SNCR systems in both the ERM and ADEC documents and is in general agreement with the technical information provided in each. Information relating to SNCRs was also solicited from BACT Process Systems. Their response, included as Appendix B, also supports the conclusion that SNCR systems appear to be technically feasible.

The actual performance of a SNCR system can vary significantly based on the actual flue gas flow, the flue gas conditions and constituents emitted from each boiler. Given the boiler's size, their stoker and moving grate combustion method, and their limited back-pass configuration, Stanley Consultants would recommend retaining a SNCR System and Equipment Supplier to perform an engineering study prior to the finalization of any BACT determination, revising the air permit to restrict NO_x emissions, or concluding that SNCR technology is a technically feasible solution. The study would generally include steps (a) through (d) as identified in Appendix B. The steps consist of an assessment of existing conditions and fuels and the development of a computational model of the boiler. The results of the study can be used to optimize furnace combustion conditions, select the preferred reagent (ammonia versus urea), locate reagent injection nozzles, and predict reagent consumption and system performance for inputs to a financial model and capital outlay of SNCR for comparative efforts to the age, condition, and expected longevity of the existing boilers.

Section 3

Discussion of SO_x Control Options

The original ERM BACT Analysis provided a limited discussion of Flue Gas Desulfurization (FGD) that focused generally on wet or dry type systems. While there is only one Wet FGD technology, there are several technologies that are considered to be “dry” or “semi-dry” FGD processes. Each of these technologies have benefits and limitations that should be individually considered to determine technical feasibility, on a site-specific basis. Additional information on specific types of dry FGD equipment was provided in December of 2017 as an addendum to the original report. This addendum discussed the technical merits of Spray Dryer/Absorbers (SDA) and Dry Sorbent Injection (DSI) in additional detail. The results of the technical evaluation presented in both the primary report and the addendum concluded that all three of the evaluated technologies (Wet FGD, SDA, and DSI) were technically feasible. The subsequent economic evaluation, however, eliminated each technology due to their evaluated cost effectiveness. Each technology was estimated to have costs that exceeded $20,000 per ton of SO_2 captured.

The ADEC BACT Determination was in general agreement with the rationale used by ERM to determine the technical feasibility of the three FGD systems evaluated. It also reached the same conclusions regarding the cost effectiveness of the Wet FGD and SDA technologies. Both systems were far too expensive when compared to the predicted reduction in emissions. The ADEC calculation of cost effectiveness for a DSI system, however, resulted in a significantly lower cost per ton of SO_2 removed. The conclusion reached by ADEC in their BACT Determination was that a DSI system was both technically feasible and cost effective, therefore DSI qualified as BACT.

Stanley Consultants was asked to review the BACT Analysis and BACT Determination and to provide technical input where necessary. We were also asked to review the economic analyses provided in both documents and to develop an independent estimate of capital (initial investment), operating, and maintenance (annualized) costs for a DSI system. Finally, we were asked to provide technical and economic information for a Circulating Dry Scrubber (CDS) FGD system. This was based on a recent determination by ADEC that the CDS technology has been successfully implemented as a FGD device in other industrial coal boilers, and therefore it must be included in the BACT analysis.

Wet Flue Gas Desulfurization and Spray Dryer Absorbers

Stanley Consultants reviewed both the BACT Analysis and the BACT Determination and agrees with the conclusion that the Wet FGD or SDA controls will not be cost effective and therefore are not BACT.

Circulating Dry Scrubbing

As previously stated, Aurora Energy recently received a request from ADEC to include Circulating Dry Scrubbing as a commercially available control technology in the BACT Analysis. The information in this section is structured to compare the CDS technology to a SDA system. The chemical process by which the sulfur is removed from the flue gas is the same in both technologies, however, there are several differences between the two systems that have significant impacts on the technical viability and cost effectiveness of each system.

Both the CDS and SDA technologies, for industrial coal fired applications, employ an alkaline reagent of calcium hydroxide, hydrated quicklime, and fly ash, which is collected from the combustion process. The calcium hydroxide reacts with Sulfur ioxide (SO_2) and sulfur trioxide (SO_3) of the flue gas to form calcium sulfite and calcium sulfate. The calcium sulfite and calcium sulfate, unreacted calcium hydroxide, and fly ash are collected downstream of the acid gas scrubbing process by a baghouse, and a considerable portion is "recycled," back to the scrubber to offset reagent costs by utilizing available unreacted alkalinity of the fly ash. The fly ash particles also serve to increase the available surface area for reactions to occur. Both processes also depend on the addition of water to humidify the flue gas. In general, the greater the humidification, the lower the alkalinity stoichiometry, which reduces reagent consumption. To prevent corrosion downstream of these scrubbers and promote the longevity of downstream equipment (namely fluework, particulate collection, and stack), the humidification is limited to operating above the saturation temperature, referred to as the approach temperature.

The method by which the flue gas stream is humidified is an area where the SDA and CDS scrubbing processes diverge.

In the SDA process, water for humidification is delivered as a portion of the lime and ash constituents. The water, lime, and ash slurries are pumped through recirculation loops and fed to an atomization feed system. The slurry that is fed to the atomizer is then atomized into small droplets which are dispersed in a passing flue gas stream inside an absorber or scrubber vessel. Once dispersed in the flue gas, a chemical reaction occurs, and the gas stream is scrubbed of the SO_2 and SO_3 pollutants. Since the slurry reagent is hydraulically conveyed by pumping, the SDA process can sometimes leverage existing infrastructure such as the particulate collection equipment. The ability to integrate a SDA system into an existing flue gas system limits the capital outlay necessary for a targeted level of compliance. The potential to leverage existing infrastructure is dependent on numerous factors such as existing equipment layout and condition, site spatial limitations, and original design parameters of the existing particulate collection equipment.

The humidification of the flue gas stream for a CDS scrubbing process is essentially decoupled from the hydrated lime and ash constituents. Water for gas humidification is mechanically atomized into the passing flue gas stream and the dry alkaline products are conveyed to the CDS vessel using air slide conveyors. Air slide conveyors utilize an air permeable fabric, which is stretched across a rectangular enclosure flow path, to aerate particulate material, and allow the force of gravity to covey the material down the sloped surface. The alkaline material and water injection (humidification) typically occurs after a venturi assembly that increases the velocity of the passing flue gas stream to establish a fluidized bed of alkaline material. As the flue gas passes through the bed of alkaline material, it is scrubbed of the SO_2 and SO_3. The use of air slides to convey the fly ash from the particulate collection device (typically a baghouse) back to the scrubber necessitates that the particulate collector (baghouse) be placed at higher elevations. This will ensure that the proper slope is established between the collector and the injection point on the absorber tower. It is technically challenging to take an existing particulate collector and elevate it, so CDS technologies are typically purchased with an absorber vessel, air slides, particulate collection device, and waste ash systems. This allows the integration of the required elevation differences and the steel and foundations necessary to accommodate the higher elevation construct. Due to the additional equipment, steel, and deep foundations necessary, these factors typically increase the capital outlay for a CDS technology.

Additional information on both SDA and CDS technology can be found in Chapter 34 of STEAM, Its Generation and Use, 42nd Edition, Babcock and Wilcox, Inc. Reference Figure 10 on Page 34-15 for an illustration of a typical SDA installation and Figure 17 on Page 34-21 for an illustration of a typical CDS installation.

The information above indicates that CDS and SDA technologies are similar in their nature and operation. However, the installation of a CDS frequently requires the installation of a new particulate collector, where the SDA system may not. The CDS equipment itself, along with the additional equipment needed for proper operation, will result in an initial (capital) cost that is significantly higher than an equivalent SDA system. Given that the ADEC BACT Determination has already established that a SDA system is not cost effective (Table 4-3, Page 12), it can therefore be concluded that the CDS system is also not cost effective, and therefore is not BACT.

Dry Sorbent Injection (DSI)

Stanley Consultants has reviewed the technical information provided in both the BACT Analysis and the BACT Determination relating to DSI systems. Based on our experience with DSI applications, we agree that DSI controls are technically feasible. Given the discrepancy in the evaluated cost effectiveness between the two reports, Aurora Energy retained Stanley Consultants to provide an independent estimation of the actual capital investment and annualized costs for a dry sorbent installation at the Chena Plant. The primary goal of this effort was to develop a site-specific cost estimate by identifying the costs to procure and install the specific equipment and components that are required for the Chena plant. Reference Section 4 of this report for additional information.

Section 4

Project Cost Estimates

Disclaimer

The information presented in this section was developed using a methodology intended to produce a result that represented the lowest reasonable cost for the project. The cost information provided herein is not a realistic estimate of actual project costs and should not be utilized for project budgeting purposes or other financial predictions.

Design Basis

The following data and assumptions were utilized to identify the system performance requirements and scope of supply for both the DSI equipment vendor and the construction contractor. Equipment and piping (internal to silo skirts and sorbent preparation building) costs for the DSI systems were developed by BACT Process Systems, Inc. BACT supplied the DSI system that was recently installed at Eielson AFB, and therefore was already familiar with this type of application. Additional information relating to the BACT scope of supply can be found in Appendix C. Balance of Plant (BOP) piping, electrical, and foundations were estimated by Stanley Consultants, as described below.

Boiler Performance and Flue Gas

The coal used at both the Eielson AFB and Chena Plants is supplied from the Usibelli Coal Mine in Healy, Alaska. Boiler heat input, flue gas flows, and uncontrolled SO_2 emissions rates for the Chena Plant were obtained from previous flue gas studies. The available coal data and the information provided in the studies was utilized to determine storage needs, equipment sizes, and required sorbent feed rates.

Dry Sorbent Unloading, Storage, Preparation, and Injection System

The BACT proposal includes the following equipment:

- Sorbent unloading equipment suitable for transporting sodium bicarbonate from a railcar to a bulk storage silo. This equipment includes unloading blowers, coolers, piping and piping components.

- Two bulk storage silos with a total storage capacity that are sufficient for three months of continuous full load operation.
- Sorbent transfer equipment for moving the sorbent from the bulk storage silos to the day bins located in a sorbent preparation building including transport blowers, coolers, and associated piping
- Sorbent mills for optimizing the particle size of the sorbent prior to injection into each boiler flue
- Sorbent injection equipment including filter receivers, airlock feeders, blowers, coolers, and piping up to the wall of the sorbent preparation building.
- All piping between the railcar unloading skid and the sorbent prep building.
- All piping inside the sorbent prep building.
- Sorbent injection lances
- Dedicated PLC's for the control of all equipment included in the proposal
- Engineering to facilitate the integration of the sorbent control system into the plant control system
- Computational Fluid Dynamics (CFD) of each flue to confirm predicted sorbent effectiveness

Additional BOP equipment, ancillary support systems, foundations that are required for the DSI system, but were not included in the BACT vendor proposal have been accounted for by Stanley Consultants in the cost estimate. This scope includes:

- Piping between the sorbent preparation building and the injection lance on each boiler's respective, outlet flue.
- Additional ductwork on Boiler 5 to increase sorbent resonance time prior to the baghouse
- Electrical feeds and equipment required to support the BACT vendor equipment (new feeds and equipment only, the suitability of the existing plant electrical system was not evaluated)
- Foundations
- Sorbent preparation building and interior structures
- Miscellaneous steel and supports

Equipment Layout

The cost estimate is based on the following approximate equipment locations:

- Unloading Equipment
  - North of Chena River
  - A rail spur adjacent and immediately northwest of the existing coal unloading building on the north side of Phillips Field Road
- Bulk Storage and Transfer Equipment
  - North of Chena River
  - Adjacent to the existing coal pile on the south side of Phillips Field Road.
- Sorbent Preparation Building
  - South of Chena River
  - Adjacent to the existing baghouse

See the sketch included as Appendix C for additional information on the proposed equipment locations and interconnecting piping.

General Assumptions

The estimated accuracy of this Opinion of Probable Costs is +50% and -15%. The approach used during the cost estimating effort was to make every reasonable assumption to simplify the project and reduce the estimated capital cost. Preliminary design activities, such as general arrangements and system integration evaluations were conducted to determine the essential project scope that would be required. Existing systems were assumed to have sufficient capacity to support the additional DSI equipment without modification. Existing foundations were utilized to estimate the cost of foundations for the new equipment, without consideration for recent code changes or review of recent geotechnical study results. Every effort was made to develop an estimate of the lowest realistic cost necessary to install DSI at the Chena Power Plant. This approach was utilized to reduce the downside uncertainty associated with the projected cost and to reinforce the conclusion that a DSI system is not a cost-effective emissions control alternative.

Given the approach outlined above, many potential design considerations that would typically add significant cost to any project were assumed not to be necessary. In general, if it was not apparent that a cost was essential to the completion of the project, it was omitted from the cost estimate. Design considerations that were intentionally undervalued or omitted from the estimate include, but are not limited to:

1. Hazmat abatement (asbestos, lead, PCB’s, soil remediation)
2. Subsurface Investigations (Geotechnical Report)
3. Existing soil conditions and impact on foundation requirements
4. Impacts of project on existing electrical system (capacity, redundancy, expansion requirements)
5. Structural capacity of existing buildings and steel structures
6. Seasonal work phasing / productivity
7. Expansion of plant utilities (air, cooling water, electrical, HVAC)

8. Rail spur engineering or construction. Existing spur was assumed available and appropriately configured for tank car staging, without primary rail operating disruptions.
9. Owner's costs, including owner's project management, owner's engineer, startup sorbent, spares, and permitting costs were excluded from this estimate.
10. Project costs related to taxes, duties, and tariffs.
11. Owners contingency

Stanley Consultants has provided cost estimates for several recent projects at various locations in the State of Alaska. Our experience to-date has been that the use of typical cost estimating resources (in this case, RS Means) will result in a cost estimate that is significantly below the costs that are actually incurred by the Owner. Installation costs used in this estimate were taken directly from RS Means. Rates were factored slightly upward to account for construction costs in interior Alaska.

All costs are expressed in January 2020 US dollars and a 14-month escalation prior to construction has been included.

Technical Methodology and Assumptions

The methodology utilized to develop project quantities along with the subsequent procurement and installation costs is detailed below. Several assumptions were made about the equipment requirements and BOP aspects concerning the installation of a dry sorbent injection system at the Chena Power Plant. The most significant assumptions, by discipline, are as follows.

General

Quantities of commodity products (piping and electrical cable) were based on distances scaled from Google Earth satellite imagery. Determined distances were then multiplied by an aggregate cost for material and labor obtained from RS Means Cost Estimation references. These costs include estimated commodity quantities along with any other components that are necessary for proper installation. The material and labor unit pricing for each of the components indicated were multiplied by a factor to obtain representative pricing in Fairbanks, Alaska. The summation of the aggregated costs, for each unit was divided by the measured distances to determine the unit costs presented. Factored RS Means data was also utilized to estimate equipment installation costs.

General craneage and forklift costs were also estimated based on RS Means costing data and multiplied by a factor to obtain representative pricing for the Fairbanks, AK location. Durations were estimated based on the anticipated project schedule. Cranage costs for pile driving operations were considered separately.

Civil / Structural

Stanley Consultants has assumed that all heavy structures or structures with a low tolerance for possible settlement will be founded on deep, pile foundations. This is based not only on the soil bearing capacities indicated by the rail unloading building foundation design drawings, but on the proximity of these structures to the river bank.

All light structures that can tolerate a minor amount of settlement were assumed to be founded on shallow, spread footings bearing on soils over-excavated and replaced with structural fill.

Unit costs for drilled caissons are based upon RS Means data for 24 inch diameter pipe piles driven in wet ground. Concrete fill will then be placed in the pipe above the soil plugs. Adjustments were made to the RS Means labor rates using blended wage rates for this project. It was assumed that a 150-ton crane with pile leads and pile hammer will be used. Civil excavation is assumed to proceed with heavy construction equipment.

Concrete is assumed to be batched at a batch plant with material costs based upon US rates. Concrete placement hours are based upon RS Means hours for manual placement adjusted by the productivity factor.

Structural steel was estimated by lineal feet for a pipe bridge, by square feet for platforms and by piece for the pipe supports.

Electrical

The existing master one-line diagram identified two 600A spare breakers on the 480V switchgear. It is assumed the existing electrical system has spare capacity to utilize these spare breakers. These spare breakers would each feed an outdoor motor control center (MCC) rated at 600A each. No modifications to the existing electrical infrastructure, no alternate power feeds, and no protective relay replacements were included in the electrical cost estimate. Note: modifications may be required but were not included herein.

It was assumed that conduit would be routed above grade using existing building columns or support steel. Cable tray may be used as space allows. Above grade routing of circuits is the most economical. New conduit support steel was not included in the cost estimate.

The only below grade electrical installation is for the bare copper ground grid and ground rods surrounding the new equipment and MCC locations and would connect to the existing ground grid in a few locations.

Mechanical

The facilities existing features have sufficient margin and correct configuration to be used to support the sorbent conveyance piping, which the vendor has indicated as 6” schedule 80 carbon steel pipe. Excessive ancillary steel for piping supports or to augment existing steel features has not been included in the cost estimate.

Piping and supports in the sorbent storage silos and sorbent preparation building were provided by the vendor in the pricing and was not estimated as part of the BOP cost estimate.

Instrumentation & Controls

The quote from the equipment vendor includes the majority of the instrumentation and controls scope. The cost estimate includes costs for miscellaneous materials and engineering services provided by the existing control system vendor to facilitate the integration of the DSI system controllers.

Equipment Performance, Sizing, and Pricing

Sorbent consumption numbers and equipment sizing were developed based on typical performance characteristics. These characteristics are typical of a flue gas system that operates at or near 500 °F and has sufficient duct length ahead of a baghouse to ensure at least 2 to 3 seconds of resonance time for the sorbent. The flue gas streams from the Chena boilers operate at significantly lower temperatures (300 to 350 °F). The potential reduction in sorbent performance due to the existing flue gas temperatures has not yet been evaluated. Adjustments to the maximum capture rate or sorbent feed rate may be determined to be necessary as the preliminary design develops. The quote obtained for the DSI system and equipment can be found in Appendix C.

Other equipment pricing is identified in the cost estimate in Appendix D. Equipment costs include an allowance for shipping, technical field supervision during erection and commissioning, and training.

Contractor Cost Assumptions

Project indirect costs include costs to manage, supervise, provide safety oversight/reporting, construction procurement, QA/QC, security, start-up and commissioning, housekeeping staff, and insurance requirements to support the project. These costs are listed at the bottom of the cost estimate summary sheet and are calculated as a percentage of the bare costs. The prime contractor indirect labor and labor burdens on prime contractor's labor can vary considerably from 10% to 60% of bare costs additional depending upon owner stipulated requirements and scope concerning the indirect costs listed.

Contractor profit was estimated at 10% for this cost estimate. In addition to the projects risk, profit also has a strong dependency on the owner's requirements concerning construction activities, competitiveness and other market conditions, and the availability of trades necessary to execute the work.

The cost estimate assumed that the prime contractor will self-perform all aspects of the work. Typically, prime contractors need to subcontract civil, electrical, and architectural work. Each of these subcontractors to the prime contractor have their own overhead and profit that is then marked up again by the prime contractor. No subcontract to the prime contractor mark-ups have been assumed in the cost estimate.

Owners Cost Assumptions

Project costs that are unrelated to the construction contract were also excluded from the cost estimate. These costs include administrative expenses, O&M mobilization and training, security surveillance, owner insurance during construction, and testing and commissioning. Proposed non-construction costs for the example projects were reviewed and converted to a value expressed as a percent of total construction cost. These values were then used as a guide for approximating non-construction costs for this project.

Opinion of Probable Cost

Based on the information above, the current minimum estimate of probable cost for a DSI system is as follows:

- Total Installed Cost: $20.6 MM
- Sorbent Cost: $550/Ton, Delivered

Sorbent pricing information provided by BACT in their proposal was supplied by a sorbent vendor based on data from the year 2000. Stanley Consultants is aware of sorbent pricing from other operators in the region, but we have not been given explicit permission to identify the price or the plant in question. The price identified above is our best estimate for current pricing based on the information that is available at the time of this report.

Appendix A

SCR Information

BACT PROCESS SYSTEMS, INC.

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(847) 577-0950
FAX: (847) 577-6355
E-MAIL: bact_process@sbcglobal.net

November 15, 2018

Mr. John Solan, P.E.
Senior Mechanical Engineer
STANLEY CONSULTANTS
8000 S. Chester St., Suite 500
Centennial, CO 80112

RE: Aurora Energy NOx Control / BACT File No. 18113

Dear John,

Following our conversation of yesterday, I have talked to the technical personnel at Haldor Topsoe, a leading catalyst supplier.

Here are their comments for SCR:

A. Minimum temperature for Catalyst: 350°f.
B. 50% turndown is acceptable in the Reactor.
C. Catalyst will work at 800-850°f, they have a number of installations in coal fired boiler. However, they caution SO_2 level should be taken into account if the SCR is before economizer and dry injunction.

Regarding the SNCR, I am attaching two write-ups we prepared for incorporating SNCR into the coal fired boilers. I believe this may be useful to you in your investigation of this approach.

Please feel free to call me with any questions you may have.

Best regards,

BACT PROCESS SYSTEMS, INC.

N.S. ("Bala") Balakrishnan
President

From: Dale T. Pfaff
To: Solan, John
Cc: Reid Thomas
Subject: FW: Current Lower Operating Temp Limit for SCR Catalyst
Date: Tuesday, December 4, 2018 4:29:29 PM

John:

I apologize for the delay in this response. In discussing this with FTEK's SCR Group, the usual minimum temperature for catalyst is ~400 °F for a reasonable catalyst volume. If the temperature falls much below that, one has to consider reheating the flue gas. It may become more economical to heat the flue gas back up as opposed to buying additional catalyst. However SCR reactions will still occur down to 350-365 °F. 365 °F has been quoted as a cutoff by one of our catalyst suppliers.

Please let me know if this answers your question.

Dale Pfaff
Fuel Tech
(847) 504-6650

Begin forwarded message:

> **From:** "Solan, John" <SolanJohn@stanleygroup.com>
> **Date:** November 28, 2018 at 9:46:26 AM CST
> **To:** "Dale Pfaff (dpfaff@ftek.com)" <dpfaff@ftek.com>
> **Subject: Current Lower Operating Temp Limit for SCR Catalyst**
>
> Dale,
> Can you answer a very quick question for me? What is the current lower operating temperature limit for commercially available SCR catalyst?
> I need some documentation from a vendor for this BACT study that we are doing for Aurora Energy in Fairbanks.
>
> Thanks in advance,
> -John

John Solan, P.E.*, Senior Mechanical Engineer
STANLEYCONSULTANTS, 8000 S. Chester St., Suite 500, Centennial, CO 80112
T: 303.649.7830 | stanleyconsultants.com
* Registered in the States of North Carolina, Colorado, and Alaska

Appendix B

SNCR Information

BACT PROCESS SYSTEMS, INC.

3345 N. ARLINGTON HEIGHTS RD. SUITE E
ARLINGTON HEIGHTS, IL 60004-1900
(847) 577-0950
FAX: (847) 577-0355
E-MAIL: bact_process@sbcglobal.net

STEPS TO DESIGN SNCR IN EXISTING BOILER

(a) Visit the plant to inspect the boiler

(b) Review the following information:

i. Boiler design drawings including grate and overfire air system arrangement
ii. Coal analyses (all possible sources)
iii. Performance predictions

(c) Estimate furnace exit gas temperature (FEGT) based on standard manufacturer's design curves.

(d) (Optional) Use computer modeling to determine the following furnace gas conditions:

i. Temperature profiles:

1. Along the length of the super heater inlet tubes
2. In the cavity between the super heater and boiler bank

ii. Gas flow profiles
iii. Estimates of O_2, CO and NO concentrations
iv. Potential for changing furnace combustion conditions (over fire air flow and distribution, flue gas recirculation, etc) to reduce NO formation

(e) Design the Urea injection system including:

i. Quantity of urea to be injection to meet expected control requirements including sufficient excess capacity
ii. Number of spray nozzles
iii. Location of spray nozzles
iv. Nozzle size, arrangement (using Caldyn nozzles) and spray pattern

v. Expected performance at full and ¾ load

(f) Integrate the injection system design with the design of the urea delivery, storage and handling system

REVIEW AMMONIA INJUNCTION SYSTEM:

i. Quantity of ammonia to be injection in the cavity between the superheater and boiler bank to meet the expected control requirements and with sufficient excess capacity

ii. Number of spray nozzles
iii. Location of spray nozzles
iv. Nozzle size, arrangement (using Caldyn nozzles) and spray pattern
v. Expected performance at full and ¾ load
vi. Safety issues

i. Evaluate potential NO reduction techniques:

i. Review the modeling results (see (e)(iv) above
ii. Identify potential fuel and air system hardware changes (in any) and design, specify, fabricate components as appropriate
iii. Identify operational changes (if any) and incorporate into the testing as appropriate

j. Determine additional instrumentation and control system requirements
i. Furnace gas temperature measurements
ii. Ammonia slip monitors
iii. Other

2. Prior to Boiler Restart-up

a. Install urea handling and injection system

b. Install furnace wall penetrations for temperature profile measurements and subsequent urea injection trials

c. Install boiler wall penetrations for cavity temperature profile measurements and subsequent ammonia injection trials (if needed)

d. Install other boiler penetrations for temperature and gaseous measurements as needed

e. Install hardware changes from (1)(i) as appropriate

f. Install additional instrumentation (see(1)(j) above)

g. Conduct "cold boiler" testing
   i. Coal distribution onto the grate
   ii. Adjust fuel distributor settings as appropriate
   iii. Overfire airflow distribution and penetration

3. Engineering Activities during "10-Day" Testing Period

a. Observe boiler operations following achieving steady and sustained boiler operations at or near full load

b. Boiler gas temperature profile measurements
   i. Furnace exit along length of superheaters
   ii. Superheater outlet
   iii. Boiler bank outlet
   iv. Economizer outlet
   v. Airheater Outlet
   vi. Scrubber/ID fan outlet

c. Determine the sensitivity of FEGT measurements with changes in boiler operations
   i. Using the "as-found" boiler firing configuration
   ii. Following operational adjustments(load, excess air, air and fuel distribution (refer to (2)(g) above), etac.)
   iii. Using the hardware changes identified in (2)(e) above
   iv. Determine the effects on furnace NO levels

d. Establish the firing conditions that product the "best" FEGT profile with minimum NO formation for use with urea injection.

e. Establish the firing conditions that produce the "best" temperature profile in the cavity with minimum NO formation for use with ammonia injection

f. Conduct initial urea injection trials using (d) above
   i. Vary the urea Normalized Stoichiomeatric Ratio (NSR)
   ii. Vary the urea spray pattern between the injection nozzle matrix

iii. Evaluate differing nozzle sizes and arrangements
iv. Determine:
1. Impacts on NO reduction
2. Impacts on ammonia slip
3. Effects on FEGT variations

g. Repeat (f) above with a second firing arrangement that achieves a different FEGT profile

h. Repeat (f) above with a third firing arrangement that achieves a different FEGT profile

i. Analyze and report the results of trials

4. If Emission Levels ARE Acceptable

a. Select the best arrangement for urea SNCR from the tests conducted in (3)

b. Operate the system over long-term (30 to 60 days)

c. Prepare recommended operating guidelines

d. Conduct boiler operating training session(s)

e. Assist (as needed) with compliance tests

f. Assist(as needed) with long term urea injection system operations and emission controls

5. If Emission Levels ARE NOT Acceptable:

a. Conduct initial ammonia injection trials using (3)(e) above
i. Vary the ammonia Normalized Stoichiometric ratio (NSR)
ii. Vary the ammonia spray pattern between the injection nozzle matrix
iii. Evaluate differing nozzle sizes and arrangements

iv. Determine:
1. Impacts on NO reduction
2. Impacts on ammonia slip
3. Effects of cavity temperature variations

b. Analyze and report results of trials

6. If Emission Levels ARE Acceptable, see (3) above

7. If Emission Levels ARE NOT Acceptable:

    a. Determine the firing arrangement that produces the optional FEGT and cavity temperature for combined urea/ammonia SNCR operations from (3)(d)+(e) above

    b. Conduct initial urea/ammonia injection trials using (a) above
        i. Vary the ammonia Normalized Stoichiometric Ratio (NSR)
        ii. Vary the ammonia spray pattern between the injection nozzle matrix
        iii. Evaluate differing nozzle sizes and arrangements
        iv. Determine:
            1. Impacts on NO reduction
            2. Impacts on ammonia slip
            3. Effects of cavity temperature variations

    c. Analyze and report results of trials

8. If Emission Levels ARE Acceptable, see (4) above

BACT PROCESS SYSTEMS, INC.

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ARLINGTON HEIGHTS, IL 60004-1900
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SNCR FACTS

REAGENT:	UREA OR AMMONIA
NOx REDUCTION	30% - 50%
TEMPERATURE:	NH3 = 1600 oF – 2000 oF
	UREA = 1650 oF – 2100 oF
RESIDENCE TIME:	.5 SECONDS
AMMONIA SLIP:	5-10 PPM
STORAGE UREA CONCENTRATION:	50% - 70%

Appendix C

DSI Information

BACT PROCESS SYSTEMS, INC.

3345 N. ARLINGTON HEIGHTS RD. SUITE B
ARLINGTON HEIGHTS, IL 60004-1900
(847) 577-0950
FAX: (847) 577-6355
E-MAIL: bact_process@sbcglobal.net

November 1, 2018

Mr. John Solan, P.E.
Senior Mechanical Engineer
Stanley Consultants
8000 S. Chester Street, Suite 500
Centennial, CO 80112

RE: DSI for Aurora Energy / BACT Proposal No. 1899-R1

Dear John,

We are revising our proposal in the light of your comments. The Emissions and sorbent usage from the boiler is based on recent information from you: on 0.39 lbs. of SO2/MBTU these calculations are based on using a weight ratio of 2.6 lbs. of sodium bicarbonate to 1 lb. of sulfur and a NSR of 1.3; Sulphur at .28%; Heating Volume of 7,600; 80% removal of SO2.

BOILER	MBTU/HR	S02 PPH	SODIUM BICARBONATE PPH
1	76	29.64	100
2	76	29.64	100
3	76	29.64	100
4	269	139.88	400
		TOTAL 228 PPH	700 PPH
			0.35 Tons/Hr.
	Per Month:	8.4 Tons/Day	252 Tons

Bicarbonate Storage

For four months; we need 756 Tons of sorbent
(2) Silos: 518 Tons capacity each
TOTAL CAPACITY = 1,036 Tons
Silo Size: Same as Eielsen

Cost of Sodium Bicarbonate = $123,480 per month; this is based on estimate by Solvay for year 2000 delivery: $250 plus, $240 freight.

Scope of Supply

1. (2) Bolted Storage Silos – 22' DIA x 100' tall with bin-vent level control and bin vibrators; capacity = 1,036 tons; storage silo complete.
2. (1) Rail car unloading and diverters to fill silos located 500' away; rate = 33,000 PPH, blower = 200 HP; installed spare; backup blower.
3. (3) Day bins with pneumatic conveying from storage silos. Conveying distance 1,000', 6,000 PPH capacity, blower = 200 HP; blowers are spared.
4. (3) Classifier mills; 1,000 PPH capacity, 75 HP total, connected HP (for 2). The 75 HP is the sum of the grinding motor, classifier motor, brakes, and VFD.

5.&6. (3) Filter receivers with conveying blowers. Milled material conveying material from mill to filter receivers. (2) Blowers 75 HP total; total connected.

7. (4) Injector sets to be installed on duct work.
8. (1) Dedicated compressor.
9. (1) NEMA 6 control panel with microprocessor.
10. Integration to the boiler control panel.
11. CFD modeling and programing.
12. All pneumatic piping up to the reagent building. All piping within the sorbent prep building by BACT. Pipe from the building wall for the 4 pipes leading to each stack by customer. Air coolers are provided to minimize puffing of the reagent.
13. Sorbent building and foundation by customer.

Budget Sell Price: $4,900,000
Freight: $ 200,000
F.O.B. Shipping Point
Taxes Extra

If you have any questions, please let me know.

Best regards,

BACT PROCESS SYSTEMS, INC.

N.S. ("Bala") Balakrishnan
President


Aurora Energy LLC
Chena CHP Plant
N
Sorbent Railcar Unloading Skid
Pipe & Power thru Utilidor (under road).
Sorbent Storage Silos
Sorbent Prep Enclosure
Unit 5 Injection
Unit 1 Injection
Unit 2 Injection
Unit 3 Injection
300 ft
Google Earth
© 2018 Google

Google Maps Fairbanks

Google Maps Fairbanks

Imagery ©2018 Google, Map data ©2018 Google 20 ft

20.10 ft

Appendix D

DSI Opinion of Probable Cost

Stanley Consultants INC.		Rev. 1	Job No. 28709.01.00	Page No.	1	
			Subject	Aurora Energy Chena - Dry Sorbent Injection		
Computed by	J. Smith / S. Worcester/ D. Bacon	Date 2/8/2019		Opinion of Probable Cost		
Checked by	J. Solan	Date 2/8/2019				
Approved by	C. Spooner	Date 2/8/2019	Sheet No.	1	of	1

	Item Description	Quantity		Unit Cost	Total Cost
		No. of Unit	UOM		
Engineering Services					
Engineering services provided throughout the project to assist with BOP design, technical specifications, procurement, bid evaluation, and construction observation.		1	EA	$1,873,100.00	$1,873,100
Dry Sorbent Injection System Supply					
DSI	Includes Railcar offloading, long term storage silos, day storage silos, milling, metering and feed.	1	EA	$4,900,000.00	$4,900,000
DSI Installation	Field Installation	1	EA	$1,550,000.00	$1,550,000
DSI Equipment Freight	FOB jobsite	1	EA	$200,000.00	$200,000
Structural					
Silo Foundation		2	EA	$244,304.00	$488,608
Sorbent Building Substructure		1	EA	$247,047.00	$247,047
Sorbent Building Superstructure		1	EA	$183,067.00	$183,067
Sorbent Building Exterior Closure		1	EA	$160,334.00	$160,334
Roofing		1	EA	$12,149.00	$12,149
Railcar Unloading Skid Foundation		5	CY	$650.00	$3,250
Transfer Skid Enclosure Foundation		5	CY	$650.00	$3,250
MCC Foundation		4	CY	$650.00	$2,600
Pipe Bridge by Silos - Steel	coal yard front end loader drive under.	4	TONS	$9,000.00	$36,000
Pipe Bridge by Silos - Foundations		6	CY	$650.00	$3,900
Outside Pipe Supports - Steel		10.0	TONS	$9,000.00	$90,000
Outside Pipe Supports - Foundations		40	CY	$650.00	$26,000
Inside Pipe Supports - Steel		3.00	TONS	$9,000.00	$27,000
Ductwork	100' Feet of Ductwork for Residence Time prior to PJFF	12.50	TONS	$10,300.00	$128,750
Mechanical					
Unit 1 Aggregate Piping Cost: 6" Sch 80 Pipe/Fittings/Flanges/Supports - Sorbent Prep to Injection Location		300	LF	$300.00	$90,000
Unit 2 Aggregate Piping Cost: 6" Sch 80 Pipe/Fittings/Flanges/Supports - Sorbent Prep to Injection Location		310	LF	$300.00	$93,000
Unit 3 Aggregate Piping Cost: 6" Sch 80 Pipe/Fittings/Flanges/Supports - Sorbent Prep to Injection Location		280	LF	$300.00	$84,000
Unit 5 Aggregate Piping Cost: 6" Sch 80 Pipe/Flanges/Supports - Sorbent Prep to Injection Location		200	LF	$300.00	$60,000
Electrical					
480V MCC	Mtl & Labor	2	EA	$65,177.00	$130,354
480V Panelboard and Xfmr	Mtl & Labor	2	EA	$10,200.00	$20,400
Cable - 480V - MCC, Loads	Mtl & Labor	9000	LF	$14.83	$133,436
Conduit - RGS	Mtl & Labor	6800	LF	$20.26	$137,748
Cable Terminations (Mat'l)	480V Material & Labor	496	EA	$26.11	$12,950
Light Fixtures Interior/Exterior	Surface mounted LED light fixtures (Mtl & Labor)	20	EA	$1,561.00	$31,220
Ground Grid extension	Mtl & Labor	1050	LF	$13.43	$14,100
Instrumentation & Controls					
BOP DCS Aspects		1	EA	$76,428.00	$76,428
All Terrain Forklift	45' lift, 35' reach, 9000 lb. capacity	12	WK	$6,455.00	$77,460
Hydraulic Crane	80-ton	90	DY	$4,365.00	$392,850
				Furnish and Erection Subtotal	$9,415,901
	MOBILIZATION / DEMOBILIZATION & MISC COSTS			8%	$753,272
	PRIME CONTRACTOR INDIRECT LABOR			40%	$1,538,236
	CONTRACTOR OH & LABOR BURDENS ON PRIME CONTRACTORS LABOR			15%	$1,412,385
	EQUIPMENT & SMALL TOOLS			10%	$902,305
	CONTINGENCY			15%	$2,103,315
	PROFIT			10%	$1,402,210
	BOND			2%	$350,552
				Total Construction Cost	$17,878,177
	Escalation Percent 4.00% Periods 14			Escalation (Nov 2018 - January 2020)	$852,635
				PROBABLE EQUIPMENT & CONSTRUCTION COST	$18,731,000
				PROBABLE ENGINEERING, EQUIPMENT & CONSTRUCTION COST	**$20,604,000**

Note: All costs presented in this document are Stanley Consultants' opinions of probable project, construction, and/or operation and maintenance costs. This estimate of probable construction cost is based on our experience and represent our best judgment. We have no control over cost of labor, materials, equipment, contractor's methods, or over competitive bidding or market conditions. Therefore, we do not guarantee that proposals, bids, or actual construction costs will not vary from estimates of project costs, construction, and/or operation and maintenance costs presented. The costs identified are based on Means Building Construction Cost Data, Engineering News Record Construction Cost Index, and/or vendor quotes.

From: David Fish
To: Dec Air Comment
Subject: Aurora Energy, LLC"s Comments on Draft SIP
Date: Friday, July 26, 2019 2:48:19 PM
Attachments: AE Comments on Draft SIP 07262019.pdf
BACT Analysis Addendum - Ind Eng Eval_Final_20190402.pdf

To whom it may concern,

Attached are comments provided to the DEC from Aurora on the draft State Implementation Plan for the Fairbanks North Star Borough Fine Particulate Nonattainment Area and enclosure.

Sincerely,

David Fish
Environmental Manager

Aurora Energy, LLC
100 Cushman St., Suite 210 | Fairbanks, AK 99701-4674
Office 907-457-0230 | Fax 907-451-6543 | Cell 907-799-9464
dfish@usibelli.com

July 26, 2019

c/o Cindy Heil
Division of Air Quality
ADEC
555 Cordova Street
Anchorage, AK 99501
dec.air.comment@alaska.gov

Subject: Aurora Energy, LLC's (Aurora) Formal Comment to Proposed Regulation Changes Relating to Fine Particulate Matter ($PM_{2.5}$); Including New and Revised Air Quality Controls and State Implementation Plan (SIP).

The DEC released on May 14, 2019 for public review, the Serious Area State Implementation Plan (SIP) for the Fairbanks North Star Borough (FNSB) Fine Particulate ($PM_{2.5}$) Nonattainment Area (NAA). Public comments are due by 5:00 pm on July 26, 2019. Aurora Energy, LLC (Aurora) appreciates the opportunity to comment on the SIP and the collaborative effort with the Alaska Department of Environmental Conservation (ADEC) to provide a means to attain the $PM_{2.5}$ 24-hour standard that is sensitive to the economics of industries and the communities affected.

1 General Comments

Per the Clean Air Act (CAA), the Serious SIP was supposed to be submitted on December 31, 2017 to describe the Best Available Control Measures (BACM) bringing the area into attainment by December 31, 2019. The 2016 $PM_{2.5}$ Implementation rule allows states to request a 5-year extension of the attainment date (i.e., December 31, 2024) as part of the Serious SIP if attainment is not anticipated by December 31, 2019. Within the 5-year attainment date extension request, the state would outline Most Stringent Measures (MSM) to be applied towards bringing the area into attainment by December 31, 2024. However, if a request is not accepted by the EPA and the area does not meet attainment by the Serious Area attainment date (December 31, 2019) then the Clean Air Act is prescriptive and requires a plan to reduce the concentration of $PM_{2.5}$ by five percent annually. A plan is to be submitted one year after the attainment date (i.e., December 31, 2020) with details on how a 5% annual reduction will be achieved. What has been communicated through the Serious SIP draft is that the most expeditious attainment date for the area is 2029.

5% Reduction Plan

Issue: The DEC is required to submit a 5% reduction plan by December 31, 2020 which hasn't been communicated to the community and/or industry.

Request: As soon as practical, communicate the details of the plan to industry and the community.

Background:

The details of a 5% plan, or at least the outline of such a plan should be better communicated with the community. There is a lack of clarity in what measures the plan would propose. The assumption is the 5% plan will be more stringent than what is being proposed within the Serious SIP.

Device Requirements

Issue: DEC is adopting emission rates for solid fuel heating devices and requirements that do not give all devices equal consideration. Installation of coal-fired heating devices are not allowed unless they are a listed device (18 AAC50.079). There are no standards available in the regulations for the determination of a qualifying coal-fired heating device. Certain devices are not given options for installation within the regulation. Non-pellet fueled wood-fired hydronic heaters, although may have EPA certification under Subpart QQQQ, are not allowed to be installed within the nonattainment area per 18 AAC 50.077 (b) & (c).

Request:

- Develop standards to qualify the installation of coal-fired heating units. Suggested standard should be consistent with 18 g/h emission rate for existing units or 0.10 lbs/MMBtu [heat input basis] whichever is greater.
- Allow the installation of non-pellet fueled wood-fired hydronic heaters provided they are EPA certified.

Background:

The DEC is adopting several different emission rates for solid fuel heating devices which does not give all devices an equal consideration. There are EPA standards for wood stoves and hydronic heaters; also alternative standards for cordwood fired hydronic heaters.[1] These standards should be adopted without alteration. Both wood stoves and pellet fired hydronic heaters emission rates in the SIP are consistent with the 40 CFR Part 60, Subpart QQQQ standard for wood heating devices. The standards are set by the EPA and apply to manufacturers of the wood heating devices. Any such device that is approved by the EPA should be allowed in the nonattainment area, this includes outdoor hydronic heaters. Existing residential and smaller commercial coal-fired devices are required to be removed by December of 2024 and new coal-fired devices are prohibited from installation within the nonattainment area.[2] Coal-fired devices currently installed can be subject to an in-use source test to demonstrate the device meets the standard of 18 g/h of total particulate matter. This standard should also be the criteria for new residential and smaller commercial coal-fired devices. The 18 g/h standard is consistent with 0.10 lbs/MMBtu (heat input) emission rate for a unit that is rated at 400,000 Btu/hr. The Titan II auger-fed coal boilers are rated at 440,000 Btu/hr (heat output) and have undergone testing through OMNI Test Labs; the same lab that derived emission rates for the DEC which are being used in the nonattainment area SIPs. The OMNI test conducted in 2011 demonstrated that auger-fed coal fired hydronic heaters are extremely efficient. Ranking among the lowest emission rates for units tested. Emission rates of auger-fed coal-fired hydronic heaters (0.027g/MJ; **0.06 lbs/MMBtu[heat output basis]**) were consistent with EPA Certified Woodstoves (0.041 g/MJ; **0.10 lbs/MMBtu [heat output basis]**).[3] The DEC is aware that more efficient heating is better for the nonattainment area situation regardless of heating device. Acceptable standards for the installation of coal-fired units should be included within the proposed regulations. There should not only be a standard for the existing units referenced in the regulations but also an achievable emission

[1] Federal Register, Vol. 80, No.50, Monday, March 16, 2015. Pg. 13672.
[2] Section 7.7.5.1.2 "Device Requirements – wood-fired and coal-fired standards", Draft Serious SIP.
[3] OMNI-Test Laboratories, Inc. 2011. Measurement of Space-Heating Emissions. Prepared for FNSB. Retrieved from https://cleanairfairbanks.files.wordpress.com/2012/02/omni-space-heating-study-fairbanks-draft-report-rev-4.pdf

rate and standards for new coal-fired units. While there are provisions for the department's approval contingency, it does not provide a target emission rate for respective devices and fuels that are not EPA certified.

Operational Requirements

Issue: The regulation isn't clear as to whether testing can be done with retrofit control devices on non-qualifying solid fuel heating devices to demonstrate qualifying emission rates. Retrofit control devices can reduce pollution emissions significantly. Use of the devices in the nonattainment area should be incentivized.

Request:

- Clarify within the regulations that emissions testing with retrofit controls can be used to qualify the emissions from solid fuel burning devices.
- The use of retrofit control devices, provided significant reductions in emissions were demonstrated, should be incentivized through an exemption for the use of the solid-fuel heating device with retrofit controls during curtailment periods.
- Suggest a lower emission standard which would qualify the use of solid fuel burning devices during curtailment periods.

Background:

The DEC is imposing curtailments for non-exempt devices during emergency episodes. Ideally, if studies associated with retrofit control devices were to demonstrate significant reductions in pollutant emissions, it would seem appropriate to establish emission rates (i.e., 0.10 lbs/MMBtu or less) and allow for the operation of certain devices that have retrofit controls without curtailment during episodes.

Small Area Sources

Issue: Coffee roasters are required to put emission controls on their processes and small area sources are asked to submit information.

Request:

- Remove the provision requiring coffee roasters to have emission controls.
- Establish a significant level for small area sources similar to major source requirements. That is, require emission controls only if the sources are emitting greater than 70 tpy of the nonattainment pollutant or its precursor and are demonstrated as being significant contributors to the nonattainment area.

Background: The department is considering pollution control devices on small area sources, namely coffee roasters. The application of pollution control is requested even though there are no regulations governing coffee roasting as a source of pollution nor is there any justification indicating that coffee roasting has some significant impact on the fine particulate concentration in the area. Under the Clean Air Act and 2016 $PM_{2.5}$ implementation rule, major sources which emit greater than 70 tons per year of fine particulate matter or its precursors have the ability to show insignificance to the area problem through precursor demonstrations and can be exempt from the application of BACT. Not to mention, if a major source curtails their emissions to less than 70 tons per year, the source doesn't have to participate in any control technology assessment or application. Unless there is some reason to believe that 'coffee roasting' by individual roasters are emitting more than 70 tons of $PM_{2.5}$ through their process, then there is no justification for applying control technologies on those sources. The state is currently asking for information from other small area sources, such as charbroilers, incinerators, and waste oil burners. Industrial activities like incinerators and waste oil burners are subject to the state regulations. If the activity is an insignificant unit, or insignificant on an emission rate basis, category basis, or size and production rate basis as described in the state regulations under 18 AAC 50.326 (d) – (g) or the activity is not required to apply for a Construction Permits under 18 AAC 50.302, there should be no requirement for the small commercial activities unless it is known that they are contributing significantly to the problem. Suggested significance should be defined as the impact of the source to $PM_{2.5}$ concentration within the nonattainment area (i.e., 1.5 $\mu g/m^3$) consistent with the 2019 $PM_{2.5}$ precursor demonstration guidance.

2 Best Available Control Technology

The proposed SIP considers BACT for the major sources; however, authorization of the BACT determination is not finalized through the EPA. With an impending date to install BACT four years from the date of reclassification (i.e., June 9, 2021), there doesn't seem to be time for any technological changes to the community of major sources. Although the state is trying to accommodate the deadline for BACT implementation through creative agreements (e.g., Fort Wainwright), the DEC alternatively could provide justification that the implementation of BACT is both technologically and economically infeasible at this time. This option is available to the state through 40 CFR 51.1010 (3). The economically infeasible consideration is discussed later within these comments, however, a technologic infeasibility case could be considered due to the impending deadlines and the actual time it would take to design, build and implement SO_2-BACT for any facility. A cleaner approach to major source BACT would be to determine that SO_2-BACT for the community of major sources is not economically feasible. If that approach is accepted by the EPA, no further consideration would be necessary for BACT.

The ADEC has provided a BACT analysis for the Chena Power Plant (CPP) and other major sources within the nonattainment area. A top-down approach was used for the FNSB stationary sources. Aurora is providing additional information to better characterize the CPP within the context of a BACT analysis. Aurora is providing an updated emission rate, justification for technically infeasible controls for NOx, and updated capital cost for Dry Sorbent Injection (DSI). Lastly, Aurora is providing a justification for the use of a 0.25% coal-sulfur content as opposed to the 0.2% coal-sulfur content proposed by the DEC in the Serious SIP.

SO_2 and NOx emission rate

Issue: The current emission rates used by ADEC within the SIP for Aurora are not representative.

Request: Update the SIP to reflect the most current emission rates of 0.131 lbs-SO_2/MMBtu and 0.359 lbs-NOx/MMBtu as demonstrated by the source test conducted in July of 2019

Background:

Aurora's current emission rates for SO_2 and NOx referenced by the ADEC for the purposes of BACT and probably the emission inventory within this draft SIP are 0.472 lbs-SO_2/MMBtu and 0.437 lbs-NOx/MMBtu. According to the DEC, these emission rates are taken from a 2011 source test; however, those emission rates are inconsistent with the emission rates associated with the 2011 source test which are 0.398 lbs-SO_2/MMBtu and 0.371 lbs-NOx/MMBtu (See Table 1). In October 2018, Aurora conducted a source test to update the SO_2 and NOx emission rates for the CPP. The emission rates derived were 0.258 lbs-SO_2/MMBtu and 0.346 lbs-NOx/MMBtu. This test was invalidated by the DEC.

Table 1: SO_2 and NOx emission rate from November 11, 2019 source testing

Pollutant	Concentration	Conversion Factor	Cd	Fd	O2 %	Emission Rate
Units	(ppm)		(lb/scf)	(scf/MMBtu)	(%)	(lbs/MMBtu)
Sulfur Dioxide	134.3	1.66E-07	7.5E-06	9739	9.5	0.398
Nitrogen Oxide	174.0	1.194E-07	2.1E-05	9739	9.5	0.371

Subsequently, a new source test was conducted with the intent of using the information within the Serious SIP for the BACT analyses, emission inventory, and modeling. Aurora has coordinated with the DEC in order to have a representative source test to better characterize the emissions from the facility. The source test was performed on July 12, 2019 and evaluated SO_2 and NOx emissions while using representative coal. The three year average coal-sulfur content was evaluated for the period July 1, 2016 through June 30, 2019 to determine the representative coal-sulfur content. The coal-sulfur content mean was 0.12%. The source test plan was approved by the department. Representatives from the department were on-site to verify the source test, the coal feed rate, and used the department's portable monitor to measure SO_2, NOx, and other constituents during the source test.

Although the results indicated within this document are preliminary, once the source test report is finalized, it will be submitted to the DEC for approval. As mentioned, the intent of the source test is to better characterize the emissions from the CPP to use in applications within the Serious SIP like the BACT analysis, emission inventory, and modeling. The new emission rate in lbs/MMBtu of the respective pollutants are 0.131 lbs-SO_2/MMBtu and 0.359 lbs-NOx/MMBtu based on EPA Method 19 and are listed in Table 2 below:

Table 2: SO_2 and NOx emission rate from July 12, 2019 source testing

Pollutant	Concentration	Conversion Factor	Cd	Fd	O2 %	Emission Rate
Units	(ppm)		(lb/scf)	(scf/MMBtu)	(%)	(lbs/MMBtu)
Sulfur Dioxide	45	1.66E-07	7.5E-06	9780	9.2	0.131
Nitrogen Oxide	172	1.194E-07	2.1E-05	9780	9.2	0.359

Provided for reference are the emission rates derived for the CPP during the October 27, 2018 source test (See Table 3). This emission rate was used in the Emission Inventory for 2018 from the facility. The test was invalidated due to a lack of representation by the DEC at the source test. The source test utilized EPA methods and an independent 3rd party source testing company to evaluate the flue gas.

Table 3: SO_2 and NOx emission rate from October 27, 2018 source testing

Pollutant	Concentration	Conversion Factor	Cd	Fd	O2 %	Emission Rate
Units	(ppm)		(lb/scf)	(scf/MMBtu)	(%)	(lbs/MMBtu)
Sulfur Dioxide	89.1	1.66E-07	1.5E-06	9776	9.2	0.258
Nitrogen Oxide	166.2	1.194E-07	2.0E-05	9776	9.2	0.346

Technically Infeasible Pollution Control Option

Issue: Selective Catalytic Reduction is not technically feasible at the Chena Power Plant.

Request: Reflect that SCR is not technically feasible within the BACT analysis for the Chena Power Plant.

Background: Based on an engineering study conducted by Stanley Consultants, SCR was determined technically infeasible for reduction of NOx emissions from the industrial coal-fired boilers at the Chena Power Plant.[4] The optimal location of an SCR would be downstream of the baghouse on the common stack. This arrangement would provide for a constant operating gas temperature, reduces issues associated with fouling on the catalyst and locating the SCR downstream of the catalyst would prevent poisoning by the presence of ammonium sulfates created with the injection of ammonia in the flue gas. However, the temperatures of the flue gas after the baghouse are less than adequate. A minimum temperature of 350°F is required for the SCR catalysts to function correctly. The flue gas temperature after the baghouse is approximately 310°F.

Updated Capital Cost for DSI

Issue: Capital cost for DSI as provided to the DEC was determined to be $20,682,000.

Request: Use the capital cost of $20,604,000 for DSI in the BACT analysis to determine a cost effectiveness value.

Background: A refined and final opinion of probable cost is being provided for the CPP DSI which is $20,604,000.[5]

BACT Cost Effectiveness Calculations

Issue: The DEC BACT cost effectiveness values in the draft SIP for the Chena Power Plant are not representative.

Request: Change the section to reflect representative cost effectiveness values based on the representative emission rates outlined below.

[4] Stanley Consultants, Inc. (2019, April). "Best Available Control Technology Analysis – Independent Assessment of Technical Feasibility and Capital Cost". Aurora Energy, LLC.
[5] Ibid.

Background:

BACT cost effectiveness calculations were done by the DEC using established cost estimating procedures. The procedures require that inputs are adjusted to reflect the conditions of the facility assessed. Some of the key inputs identified by the DEC are as follows: the emission rate for SO_2 and NOx were 0.472 lbs-SO_2/MMBtu and 0.437 lbs-NOx/MMBtu, a retrofit factor of 1.5 was used for a difficult retrofit, an interest rate of 5.5%, and equipment life for NOx and SO_2 controls were 20 and 15 years respectively. Using the DEC inputs for wet scrubbers and SDA technologies, the cost effectiveness value and capital costs output are not consistent with the text within the draft SIP. DEC calculated the cost effectiveness for the installation of wet scrubbers and SDA to be $10,620/ton and $11,298/ton. When the DEC inputs were used within the spreadsheets, the cost effectiveness values for the installation of wet scrubbers and SDA were $14,572/ton and $15,726/ton (See Table 4 - values in parentheses) respectively. However, when the emission rate was updated in the spreadsheets to the representative emission rate from the July 12, 2019 source test (0.131 lbs-SO_2/MMBtu), the cost effectiveness value increased to $49,585/ton for wet scrubbers and $53,909/ton for SDA. Using the DEC's spreadsheets for DSI cost effectiveness, Aurora adjusted the capital cost of DSI from $20,682,000 to $20,604,000 based on refined opinion of probable cost and used the updated emission rates referenced in Table 2. The cost effectiveness value for DSI increased from $7,495/ton to $18,007/ton (Table 4).

Table 4: Updated Cost Effectiveness Value based on SO2 and NOx Representative Source Test (7/12/19)

Technology	DEC Cost Effectiveness Value (cost/ton removed)	Capital Cost ($)	Updated Cost Effectiveness Value (cost/ton removed)	Adjusted Capital Cost ($)
Selective Catalytic Reduction	$4,023/ton		Not Technically Feasible	
Selective Non-Catalytic Reduction	$2,227/ton		$2,587/ton	
Wet Scrubbers	$10,620/ton ($14,572/ton)	$57,019,437 ($87,152,852)	$49,585/ton	$82,323,012
Spray Dry Absorbers	$11,298/ton ($15,726/ton)	$51,019,437 ($81,280,628)	$53,909/ton	$77,293,649
Dry Sorbent Injection	$7,495/ton	$20,682,000	$18,007/ton	$20,604,000

Note: Values in parentheses are the output from the cost development methodology used by the DEC with inputs suggested within Section 7.7.8 "Control Strategies" of the draft Serious SIP.

Based on the adjusted values, it is not cost effective to install BACT for SO_2 at the Chena Power Plant.

Sulfur Content of Coal

Issue: Proposed BACT for coal-sulfur content of 0.2% will cut off access to tens of millions of tons of coal for UCM as well as pose a potential threat of fuel supply interruption for the coal fired power plants.

Request: Adopt a new standard of 0.25% based on semi-annual weighted averages of coal-sulfur content in shipments of coal within semi-annual periods corresponding to Facility Operating Report reporting periods.

Background:

The ADEC has proposed that Best Available Control Technology (BACT) for coal burning facilities in the nonattainment area is a coal-sulfur limit of 0.2% sulfur by weight. Usibelli Coal Mine (UCM) is the only source of commercial coal available to the coal-fired facilities within the Fairbanks North Star Borough fine particulate nonattainment area. The mine has limited ability to affect the sulfur content in the coal. There isn't a coal washing or segregating facility associated with UCM which could ensure a consistent coal-sulfur concentration. Current practice for providing low-sulfur coal to customers is identifying sulfur content of the resource through drilling and sampling efforts. However, no matter how much sampling is done, the ability to characterize the sulfur content of the coal actually mined is limited.

Within the millions of tons of coal resources available to UCM, there is a significant amount of coal with higher sulfur content than 0.2%; in fact, any limit proposed to the coal sulfur content is effectively cutting off access to tens of millions of tons of coal resources. As such, AE proposes that the coal-sulfur limit be lowered to 0.25% on an as received basis (wet) as opposed to 0.2% as proposed by ADEC. The increase in coal-sulfur content will help with coal accessibility and availability over the next decade and still provides ADEC with a 37.5% reduction in the potential to emit based from the current limit of 0.4%.

The state was silent on how the measure was to be reported or considered within a regulatory context. The ADEC's standard permit condition for coal fired boilers (Standard Condition XIII) requires that the permittee report sulfur content of each shipment of fuel with the semi-annual Facility Operating Reports. UCM currently provides semi-annual reports to all customers which includes sulfur content of each shipment of coal along with the weighted average coal-sulfur content for the six-month period coinciding with the operating reports' reporting period. UCM and Aurora propose that the standard operating permit condition remain the same and that facilities continue to provide the state with the sulfur content of each shipment of fuel; in addition, the weighted average coal-sulfur content of the shipments received by the facility during the reporting period would be referenced in the operating report.

3 SO_2 Precursor Analysis

Issue: There are inconsistencies in DEC's information with respect to SO_2. The major source contribution to sulfur-based $PM_{2.5}$ from major source SO_2 ground level concentrations have increased from 2008; even though point source SO_2 emissions have decreased while SO_2 emissions from heating oil and total SO_2 emissions have increased.

Requests:

- Change referenced $PM_{2.5}$ significance threshold from 1.3 µg/m^3 to 1.5 µg/m^3 based on the final EPA $PM_{2.5}$ Precursor Demonstration Guidelines (2019).
- Revisit SO_2 Analysis after applying representative emission rates for the Chena Power Plant for SO_2 and NOx (0.131 lbs-SO_2/MMBtu and 0.359 lbs-NOx/MMBtu).
- Clarify discrepancy between the 2008 CALPUFF model output reflecting 22% contribution to ground-level SO_2 from major sources and current CMAQ evaluation reflecting 39% SO_2 contribution from major sources.
- Reconsider SO_2 Precursor Demonstration for Major Source impact using a sensitivity analysis to determine significance.

Background:

The DEC completed an SO_2 Analysis using the 2019 projected baseline inventory and run through CMAQ model. All of the SO_2 emissions were removed from the point source sector in a knock out model run. The meteorology used was from 2008, which is consistent for all of the model runs. The SO_2 from major stationary sources were found to contribute significantly to the $PM_{2.5}$ concentrations at the State

Office Building (SOB) [1.79 µg/m^3] and at the monitoring site adjacent to the Borough building (NCORE) [1.70 µg/m^3] in Fairbanks. The impact of SO_2 from major sources was also determined to be significant at all four monitoring sites (SOB, NCORE, Hurst Road, and NPE) when an alternative approach to estimating the design value contribution from major stationary sources was applied [respectively: 2.66 µg/m^3,2.53 µg/m^3, 1.55 µg/m^3, 1.35 µg/m^3]. The DEC referenced an insignificance threshold of 1.3 µg/m^3 to determine significance; however, final PM2.5 Precursor Demonstration Guidance has changed that threshold to 1.5 µg/m^3.[6]

Regardless of the change in significance value, three of the sites (SOB, NCOR, and Hurst Road) would still be considered significant when the alternative approach to estimating the design value contribution is considered. If the impact of major source SO_2 emissions on $PM_{2.5}$ exceeds 1.5 µg/m^3, then a sensitivity-based analysis may be conducted to show that a reduction of SO_2 emissions in the range of 30 - 70% would only have an insignificant impact on lowering $PM_{2.5}$ concentration. Aurora demonstrated that there was justification to pursue a precursor demonstration using information provided in the moderate area SIP. The major source contribution to $PM_{2.5}$ from SO_2 was determined to be 1.98 µg/m^3 of water-bound ammonium sulfate. The conclusion of the exercise was that a 70% reduction in SO_2 would demonstrate insignificance of the SO_2 contribution from major sources on $PM_{2.5}$ concentration [i.e., 1.45 µg/m^3].[7] It is Aurora's opinion that a successful precursor demonstration may still be possible using a 50% reduction even considering DEC's alternative approach to estimating design value contributions from major source SO_2. However, the DEC has indicated due to sulfate model performance uncertainty and significance of the major source contribution from SO_2 emissions, there is not enough justification to pursue the demonstration.

Aurora has a few concerns with the SO_2 analysis. Probably the most significant is that the contribution of SO_2 at the SOB monitor from major sources increased to 39% from 22% as described in the Moderate Area SIP (2014). CALPUFF modeling showed that the point source SO_2 contribution to the SOB monitoring site was 22% for an episode in 2008. The emission inventory for 2008, 2013, and the projected 2019 show a decreasing trend in SO_2 emissions for point sources (See Table 5). The ratio between SO_2 emissions from oil heating and point sources (Oil Heating SO_2/Point Source SO_2) increases from 2008 to 2019 (projected) from 0.46 to 0.51 for the planning inventory in the NAA (Table 5). This would suggest that the amount of SO_2 emissions from oil increased in relation to the amount of SO_2 emissions from point sources. That fact is counterintuitive to the modeling outputs which indicates SO_2 contribution from point sources increased 18% from 2008 to 2019 at the SOB.

The total SO_2 emissions per day in 2019 is about two times what it was in 2008 and 2013 (See Table 5). The difference is attributed to an increase in Non-Road Mobile sources; in fact, a change in jet fuel between 2013 and 2019 is referenced as the cause of the increase.[8] It would seem that the likelihood for an increased impact at the monitors from SO_2 should have come from this change as opposed to the point sources.

[6] https://www.epa.gov/sites/production/files/2019-05/documents/transmittal_memo_and_pm25_precursor_demo_guidance_5_30_19.pdf
[7] Memo. Ramboll. "Summary of issues related to SO_2 precursor demonstation for Fairbanks". 2018.
[8] Section 7.6.3.2 "2019 Projected Baseline Emission Inventory", Draft Serious SIP.

Table 5: Baseline Episode Average Daily SO_2 Emissions (tons/day) by Source Sector

Source Sector	Modeling Inventory Grid 3 Domain			Planning Inventory NA Area		
	2008	2013	2019 (projected)	2008	2013	2019 (projected)
Point Sources	8.380	7.40	7.32	8.167	7.22	7.13
Area, Space Heating, Oil	4.121	3.68	3.90	3.719	3.42	3.61
Total	12.875	12.65	25.58	12.155	11.92	22.36

Note: 2008 data from Moderate Area SIP (Table 5.6-7); 2013 & 2019 data from draft SIP, Tables 7.6-10 & 7.6-12, respectively.

The increase in point source contribution of SO_2 at the monitoring sites is, therefore, perplexing. Aurora also believes that point source emission of SO_2 in the inventories may be inflated due to the emission factor used to determine Aurora's SO2 emissions (and NOx emissions). Within the BACT section of the draft SIP, an emission factor for SO_2 was referenced as being 0.472 lbs-SO_2/MMBtu. A recent source test conducted on July 12, 2019 at the Chena Power Plant was arranged specifically to better characterize the emission rates for SO_2 and NOx from the plant. The test plan was approved by the state with additional scrutiny due to its intended use. The test demonstrated an emission factor of 0.131 lbs-SO_2/MMBtu. This value is a preliminary emission rate. The final report will be provided to the DEC so that, when approved, the new emission rate would be updated in the state's databases and worksheets for the final submittal of the Serious Area SIP to the EPA.

Aurora would also like the state to clarify the discrepancy between the 2008 CALPUFF modeling, which showed a major source SO_2 contribution of 22% at the SOB monitoring site, in relation to the recent evaluation referenced under the SO_2 Analysis (Section 7.8.12.5) where major source SO_2 contribution to the SOB was 39%. Aurora would like the DEC to reconsider an SO_2 precursor demonstration for major source contribution to $PM_{2.5}$ concentration. Aurora believes a successful demonstration could be done using the provisions of a sensitivity analysis as described in the 2019 $PM_{2.5}$ Precursor Demonstration Guidance.

4 Major Source Economic Infeasibility Justification

Issue: The DEC has the option to demonstrate the economic infeasibility of SO_2 BACT for major sources within the nonattainment area under 40 CFR 51.1010 (3) based on cost effectiveness. The most cost effective value for operating BACT controls on the community of major sources to remove 1 $\mu g/m^3$ of $PM_{2.5}$ is $9,794,799 per year [See Table 7b].

Request:

- Define cost effectiveness as cost per 1 $\mu g/m^3$ of $PM_{2.5}$ for this exercise.
- Derive a cost per ton removed for each major source in the nonattainment area by adjusting operational load to represent actual SO_2 emissions in the spreadsheets for each facility provided within the appendices of the "Control Strategies" section of the draft serious SIP.
- Evaluate the cumulative annualized cost incurred by the community of major sources within the nonattainment area based on potential tons removed from implementing SO_2 BACT using actual emissions (instead of PTE).

- Correlate annualized cost of SO_2 BACT controls with results from the SO_2 Analysis section of the draft SIP (Section 7.8.12.5) to derive a cost per µg/m^3 mitigated from applying SO_2 control technologies.

Background:

Major stationary sources are a subgroup of emission sources that are given special consideration under nonattainment area provisions. Point sources with emissions greater than 70 tons per year of $PM_{2.5}$ or any individual precursor (NOx, SO_2, NH_3, VOCs) are evaluated for appropriate control. NOx and SO_2 were addressed on an emission unit specific basis in DEC's Best Available Control Technologies (BACT) determinations. The DEC's evaluation considered technical feasibility and estimates of emissions reductions to meet a defined emission limit. Operations at the facility's potentials to emit is used for the purpose of identifying a cost effectiveness for each technology in cost per ton removed.

The BACT analyses evaluate pollution control independent of the nonattainment area problem; it is simply triggered as a condition of an area defined as being in serious nonattainment of a pollutant standard. As described in the 2016 $PM_{2.5}$ Implementation Rule, the state can provide either a technologic or an economic infeasibility demonstration for control measures.[9] The argument must illustrate it is not technologically or economically feasible to implement the control measure by the end of the tenth calendar year (i.e., December 31, 2019 for the FNSB NAA) following the effective date of the designation of the area. Aurora believes that there is enough evidence to substantiate that SO_2 controls on the community of major sources is economically infeasible.

Economic Infeasibility Justification

The DEC has determined BACT is comprised of sulfur controls for major stationary sources. The DEC has also determined that sulfur controls are economically infeasible for one major source, silent on infeasibility for another, and partially economically infeasible for a couple of major sources within the NAA.[10] Per regulation, DEC has the authority to demonstrate that any measure identified is economically infeasible.[11] It is within the DEC's authority to determine that BACT for sulfur control is economically infeasible for the community of major sources in the NAA based on cost effectiveness.[12] If cost effectiveness is defined as cost per µg/m^3 removed, there is a clear justification to eliminate sulfur control measures from the community of major sources. The most cost effective value for operating BACT controls on the community of major sources to remove 1 µg/m^3 of $PM_{2.5}$ is $9,794,799 per year [See Table 7b].

Annualized Cost of BACT Implementation

The DEC derived cost effectiveness value in cost per ton removed is established through the implementation of the BACT analysis. The DEC preferred BACT controls and cost effectiveness value are referenced in Section 7.7.8 of the SIP.[13] Dry Sorbent Injection (DSI) is selected for the coal fired boilers with an 80% reduction in SO_2 and ULSD is suggested for GVEA's North Pole Plant and Zehnder

[9] 40 CFR 51.1010 (3)
[10] Section 7.7.8 of the draft Serious SIP
[11] 40 CFR 51.1010 (3)
[12] 40 CFR 51.1010 (3)(ii)
[13] Appendix III.D.7.07 Control Strategies: https://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip/

Facility with a 99.7% removal rate for SO_2. Based on the Potential to Emit (PTE) of each facility, the state derives a cost effectiveness value for the sources.

Annualized cost to implement BACT for the community of major sources are based on operating scenarios for both PTE and actual emissions (2013) [14] from the facilities. The results are illustrated in Table 6a and 6b. The cost effectiveness value (cost/ton removed) is multiplied by the amount of pollution removed (tons) to derive an annual cost for BACT for each facility. The total annualized cost is the sum of the cumulative annual operating cost for the controls on all the major sources in the NAA. The annualized costs do not include the cost of fuel switching for smaller diesel engines, backup generators and boilers that are found on the campuses of certain facilities (e.g., UAF, FWA). The total annualized BACT implementation cost to operate at the PTEs is $49,296,062; annualized cost considering actual emissions is $20,843,332 (See Tables below).

Table 6a: BACT Annualized Costs Based on Potential To Emit

Facility	BACT (SO_2 Control)	SO_2 Reduction	SO_2 Emissions PTE[3]	SO_2 Reduction[3]	Cost/ton removed [2,3]	Annualized Cost
Units		(%)	(tpy)	(tpy)	($)	($)
Chena Power Plant	DSI	80	1,004.0	803.0	$ 7,495	$ 6,018,485
FWA	DSI	80	1,168.5	934.8	$ 10,329	$ 9,655,331
NPP-EU1	ULSD	99.7	1,486.4	1,482.0	$ 9,139	$ 13,543,998
NPP-EU2	ULSD	99.7	1,356.1	1,352.0	$ 9,233	$ 12,483,016
UAF	DSI	80	242.5	194.0	$ 11,578	$ 2,246,132
Zender	ULSD	99.7	598.6	597.0	$ 8,960	$ 5,349,120
Notes: See Below.					Total Annualized Cost	$ 49,296,082

Table 6b: BACT Annualized Costs Based on Actual Emissions

Facility	BACT (SO_2 Control)	SO_2 Reduction	SO_2 Emissions (Actual)[1,3]	SO_2 Reduction	Cost/ton removed[4]	Annualized Cost
Units		(%)	(tpy)	(tpy)	($)	($)
Chena Power Plant	DSI	80	711.8	569.4	$ 8,960	$ 5,101,824
FWA	DSI	80	766.5	613.2	$ 11,235	$ 6,889,302
NPP-EU1	ULSD	99.7	142.3	141.9	$ 12,169	$ 1,726,454
NPP-EU2	ULSD	99.7	422.3	421.0	$ 9,453	$ 3,980,026
UAF	DSI	80	219.0	175.2	$ 11,578	$ 2,028,466
Zender	ULSD	99.7	73.0	72.8	$ 15,351	$ 1,117,261
Notes:					Total Annualized Cost	$ 20,843,332

1 - Table 7.6-9 "2013 SO2 Episodic vs. Annual Average Point Source Emissions (tons/day)"
2 - Sectoin 7.7.8 of SIP
3 - BACT Spreadsheets (May 2019) in SIP for Listed Facilities; adjusted AE emission factor of 0.472 lbs-SO2/MMBtu referenced in BACT Section of SIP.
4 - Cost/ton removed after adjusting operational load in BACT Spreadsheets (May 2019) to reflect actual emissions; AE emission factor of 0.472 lbs-SO_2/MMBtu

<u>Major Source SO_2 Control Cost Effectiveness: Cost per $\mu g/m^3$ $PM_{2.5}$ Removed</u>

The DEC provided an SO_2 analysis using the 2019 projected baseline inventory. [15] The DEC determined that major stationary sources were found to contribute significantly to $PM_{2.5}$ concentrations at the State Office Building (SOB) and the monitor adjacent to the Borough building (NCORE) in downtown Fairbanks. The impact at the monitors were 1.79 $\mu g/m^3$ and 1.70 $\mu g/m^3$ respectively.[16] The impact at the Hurst Road and North Pole Elementary (NPE) monitors were 0.04 $\mu g/m^3$ and 0.10 $\mu g/m^3$ respectively.

Assuming that an 80% removal of the point source emissions of SO_2 would translate to an 80% reduction to the impact from major sources of sulfur-based $PM_{2.5}$ at the monitors, the amount of $PM_{2.5}$ reduced at the SOB, NCORE, Hurst Road, and NPE monitors would be 1.43 $\mu g/m^3$, 1.36 $\mu g/m^3$, 0.03 $\mu g/m^3$, and 0.08 $\mu g/m^3$ respectively. Based on the total annualized cost for BACT controls using actual emissions ($20,843,332) the cost effectiveness value in cost per $\mu g/m^3$ of $PM_{2.5}$ removed is at the best, $14,555,400 per $\mu g/m^3$ removed and at the worst $651,354,137 per $\mu g/m^3$ removed (Table 7a). If the alternative

[14] Table 7.6-9 "2013 SO2 Episodic vs. Annual Average Point Source Emission (tons/day)"[Draft Serious SIP]ADEC
[15] Section 7.8.12.5 of the draft Serious SIP
[16] Table 7.8-26. "Design value contribution from major stationary source SO_2".Draft Serious SIP.

approach to the SO_2 design value contribution from major sources is considered then the cost effectiveness at best is $9,794,799 per µg/m³ and at worst is $19,299,382 per µg/m³ (Table 7b).

Ironically, the cost per µg/m³ removed is less at the SOB and NCORE sites where the projected design value is in compliance with the standard. The projected design value provided by the DEC for 2019 meet attainment at the SOB and NCORE sites which are of 29.72 µg/m³ and 29.01 µg/m³ respectively[17]; the attainment standard is 35 µg/m³. The 2019 design values at the Hurst Road and NPE monitors were 104.81 µg/m³ and 36.48 µg/m³, both clearly above the attainment standard of 35 µg/m³. The impact from the major sources is less significant at the sites where the 2019 projected design value violates the standard.

Table 7a: Cost Effectiveness Based on Design Value Contribution SO_2 from Major Stationary Sources

Site	Design Value Base Year 2013[1]	Projeced Design Value Year 2019[1]	Major Source Sulfur-Based Particulate Contribution[2]	BACT Reduction (80% of Direct Emissions)	BACT Reduction / Design Value 2019	Annualized BACT Cost per ug/m³ removed
Units	(ug/m³)	(ug/m³)	(ug/m³)	(ug/m³)	(%)	($)
State Office Building (SOB)	38.93	29.72	1.79	1.43	4.8%	$ 14,555,400
Fairbanks Borough Building (N	37.96	29.01	1.70	1.36	4.7%	$ 15,325,980
Hurst Road	131.63	104.81	0.04	0.03	0.0%	$ 651,354,137
North Pole Elementary (NPE)	45.3	36.48	0.10	0.08	0.2%	$ 260,541,655

Notes:
1 - Table 7.8-29 of Draft Serious SIP
2 - Table 7.8-26 of Draft Serious SIP

Table 7b: Cost Effectiveness Based on Alternative Approach to Design Value Contribution SO_2 from Major Stationary Sources

Site	Design Value Base Year 2013[1]	Projeced Design Value Year 2019[1]	Major Source Sulfur-Based Particulate Contribution[2]	BACT Reduction (80% of Direct Emissions)	BACT Reduction/Design Value 2019 x 100	Annualized BACT Cost per ug/m³ removed
Units	(ug/m³)	(ug/m³)	(ug/m³)	(ug/m³)	(%)	($)
State Office Building (SOB)	38.93	29.72	2.66	2.13	7.2%	$ 9,794,799
Fairbanks Borough Building (N	37.96	29.01	2.53	2.02	7.0%	$ 10,298,089
Hurst Road	131.63	104.81	1.55	1.24	1.2%	$ 16,809,139
North Pole Elementary (NPE)	45.3	36.48	1.35	1.08	3.0%	$ 19,299,382

Notes:
1 - Table 7.8-29 of Draft Serious SIP
2 - Table 7.8-27 of Draft Serious SIP

Fairbanks exceeds the fine particulate matter standard during winter months.[18] Control technology application on major stationary sources is permanent and transcends seasons. BACT for sulfur control on major sources is an annual solution to a wintertime problem. The application of SO_2 BACT is arguably an impractical effort. Where the pollutant concentration is either achieving or almost achieving the standard, the projected impact removed by application of BACT on the major sources is about 7% of the concentration. Since the standard is attained, removing 7% more of sulfur-based $PM_{2.5}$ for costs upward of $10 million dollars per µg/m³ seems impractical. There is a mechanism allotted within the 2016 $PM_{2.5}$ Implementation Rule for the DEC to provide a detailed written justification for eliminating, from further consideration, potential control measures for SO_2 on the community of major stationary sources based on cost ineffectiveness.

As such, Aurora supports an economic infeasibility determination for the application of BACT on all major stationary sources within the nonattainment area.

[17] Table 7.8-29. "2019 FDV for Projected Baseline and Control Scenario Calculated against a 2013 Base year".
[18] Section 7.8.6 of the Draft Serious SIP

5 $PM_{2.5}$ Emission Reduction Credits

Issue: Currently there are no provisions for the FNSB NAA within the regulations that establish emission reduction credits.

Request: Include provisions in the Serious SIP for establishing $PM_{2.5}$ emission reduction credits per 40 CFR 51 Appendix S.

Background:

Aurora Energy requests that the SIP include provisions for establishing PM2.5 emission reduction credits, as provided in 40 CFR 51 Appendix S. The SIP should recognize that the most fertile area for establishing further emission reduction credits involves reducing emissions from wood-fired residential heaters – stoves and fireplaces. The approach to accounting for dried wood emissions should consider enhanced wood-moisture reduction through a process such as kiln drying, to levels as low as 15 percent (dry wood basis) beyond the 20 percent levels in the proposed SIP and allow those lower emissions to be applied as emission reduction credits for potential future development within the Non-Attainment Area. The approach also lessens the level of involvement of agency oversight of the individual components of the SIP that are related to residential wood combustion. Residential wood combustion is an ingrained cultural component of life in Fairbanks, and the proposed enhanced drying option is likely to be well supported by members of the community. We urge consideration of this approach that will both clean the air and provide some potential for emissions increases, through offsets developed under this proposal, to further strengthen the economic viability of the Fairbanks North Star Borough community.

6 Conclusion

In summary, there are several elements to the SIP that Aurora is addressing as a part of the public comment. The DEC has an incredible task which is being addressed to the extent possible with the time and resources available. Below are summaries of the key points Aurora addressed within the comments:

- BACT requirement for coal facilities to meet coal-sulfur content of 0.2% is being contested. Auroras requests a modified BACT requirement to 0.25% coal-sulfur (as received) evaluated on a six-month weighted average using UCM analyses for each shipment.
- SO_2 and NOx emission rates being used for Aurora within the SIP are not accurate representation of the facilities emission rates. Suggest using newly established rates derived through representative source testing with representative coal.
- Additional information is provided to support technologic infeasibility of SCR, a change in the capital cost for DSI, and emission rate changes for the determination of cost effectiveness within the context of the BACT analyses.
- Aurora supports an economic infeasibility determination for the community of major sources based on the cost ineffectiveness of sulfur control technology in removing 1 $\mu g/m^3$ of sulfur-based $PM_{2.5}$ from major source SO_2 contribution.
- Aurora requests that the SIP include provisions for establishing $PM_{2.5}$ emission reduction credits, as provided in 40 CFR 51 Appendix S.
- One of the key parts to the future of the nonattainment area is the 5% reduction plan. The elements within this plan, which is anticipated for submittal at the end of 2020, have not been communicated to the community or industry. It is the opinion of Aurora that communication with the community about the elements within the 5% reduction plan is warranted and necessary.

- Solid fuel burning devices are not treated equally within the Serious Area SIP. A proposition for a common emission standard for those units that do not have EPA certification or standard to meet is encouraged. Those units with EPA standards should be allowed to operate within the NAA. Also, inclusion of emission standards and criteria for coal-fired home heating devices within the regulation is encouraged.
- Retrofit control devices should be encouraged for use to meet emission standards as necessary.
- The departments' imposition of control technologies on small sources, such as coffee roasters, is not supported. Major sources are able to take operational limits to reduce emissions to less than 70 tons per year to avoid pollution control. Small commercial sources shouldn't be subject to pollution controls unless there is evidence that their emissions are significant.

Enclosure:

Stanley Consultants, Inc. (2019, April). "Best Available Control Technology Analysis – Independent Assessment of Technical Feasibility and Capital Cost". Aurora Energy, LLC.

Best Available Control Technology Analysis

Independent Assessment of Technical Feasibility and Capital Cost

Chena Power Plant
Aurora Energy, LLC
Fairbanks, Alaska

Final
April 2, 2019

Stanley Consultants INC.
A Stanley Group Company
Engineering, Environmental and Construction Services - Worldwide

April 2, 2019

Mr. David Fish
100 Cushman Street
Suite 210
Fairbanks, AK 99701

Dear Dave:

Stanley Consultants is pleased to provide you with the final version of the Independent Assessment of Technical Feasibility and Capital Cost in support of your Best Available Control Technology Analysis. We greatly appreciate the opportunity to assist Aurora Energy in this effort and we look forward to working with you again soon.

Respectfully submitted,

Stanley Consultants, Inc.

Prepared by Jason Smith

Approved by
John P. Solan

STATE OF ALASKA
49 TH
JOHN P. SOLAN
No. ME14412
4/2/19
REGISTERED PROFESSIONAL ENGINEER

I hereby certify that this engineering document was prepared by me or under my direct personal supervision and that I am a duly licensed Professional Engineer under the laws of the State of Alaska.

My license renewal date is December 31, 2019.
Pages or sheets covered by this seal: Entire Report

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Section 1

Introduction

This report documents the results of an independent engineering assessment of the technical feasibility and probable capital costs for emissions control retrofits at the Chena Power Plant in Fairbanks, Alaska. The report is intended to supplement the information previously provided by Aurora Energy in the Best Available Control Technology (BACT) Analysis Report, including any revisions or addendums thereto. It also incorporates some of the conclusions reached by the Alaska Department of Environmental Conservation (ADEC) in their Preliminary Best Available Control Technology Determination.

Background

The US Environmental Protection Agency (EPA) has recently reclassified portions of the Fairbanks North Star Borough as a Serious PM 2.5 Non-Attainment Area. This reclassification triggers a requirement that all major sources within the non-attainment area perform a BACT analysis for particulate emissions and the emissions of any precursor pollutants. In response to this requirement Aurora Energy submitted the required BACT Analysis to ADEC in March of 2017. An addendum to the report was submitted in December of that year.

After reviewing the data and conclusions presented in the BACT Analysis, ADEC conducted their own analysis and presented the results as a Preliminary BACT Determination in March 2018. The ADEC report documented several conclusions that differed from those presented in the BACT report submitted by Aurora Energy.

Project Scope

Given the disparity in the results of the analyses, Aurora Energy hired Stanley Consultants to review the technical feasibility of control technologies for two specific precursor pollutants; Nitrogen Oxides (NO_x) and Sulfur Oxides (SO_x). In this report these pollutants may also be referred to as Nitrogen Oxide (NO) and Sulfur Dioxide (SO_2) as these are the most common forms of the nitrogen and sulfur pollutants.

Aurora Energy also requested that Stanley Consultants develop a site-specific, third-party estimate of the costs to install and operate technically feasible SO_2 emissions control equipment on the four operating boilers at the Chena Power Plant. This effort will include the development of a capital cost estimate for the identified systems, sorbent consumption rate estimates, and an estimated cost for the purchase and delivery of sorbent to site. Once these costs have been developed, Aurora Energy and their environmental consultants, Environmental Resources Management (ERM), will incorporate the estimated costs into a calculation to determine the cost effectiveness of the emissions control equipment on a basis of Dollars/Ton of SO_2 removed.

Section 2

Discussion of NO_x Control Options

The original BACT Analysis developed by ERM provided a comprehensive review of the various technologies currently available to control NO_x emissions. It also identified if each technology was technically feasible or infeasible based on the specific application at the Chena Plant. The report concluded that the only technically feasible NO_x reduction technologies were Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR). Similar conclusions regarding the technical feasibility were reached by ADEC in the Preliminary BACT determination.

Stanley Consultants has reviewed the information provided in both documents. While we are in general agreement, there are technical limitations relating to the application of SCR and SNCR technology that were not adequately addressed in either document.

Selective Catalytic Reduction

Both the ENR BACT Analysis and the Preliminary BACT Determination correctly determine that SCR technology has been successfully utilized to reduce the emissions of nitrogen oxides on industrial coal fired boilers. Both documents detail the mechanism by which the oxides are removed from the flue gas stream and the both correctly note that the chemical reaction is highly dependent on the flue gas temperature. Neither report, however, mentions the actual flue gas conditions at the Chena Plant, nor do they mention where a SCR is typically located with respect to the boiler outlet and the stack. A flue gas temperature is provided in the ADEC SCR Economic Analysis Spreadsheet (https://dec.alaska.gov/media/7381/chena-scr-economic-analysis-adec.xlsm). This spreadsheet uses a flue gas temperature of 310 °F based on information collected during a 2016 source test at the Chena Plant. This data, however, is only used to calculate the Volumetric Flue Gas Flow Rate. There is no check in the ADEC SCR Economic Analysis spreadsheet to determine if the subject emission source flue gas temperature is within a typical operating temperature range for commercially available catalyst.

Modern SCR systems for industrial boiler applications like the Chena Plant are generally located downstream of the flue gas particulate filter. This position in the flue gas system has several advantages:

- This arrangement allows a constant operating gas temperature throughout the boiler load range.
- Locating the SCR downstream of a baghouse significantly reduces issues associated with ash fouling of the catalyst blocks.
- Locating the SCR downstream of sulfur emissions control equipment will prevent the catalyst from being poisoned by the presence of ammonium sulfates which are formed when ammonia is injected into the flue gas stream in the presence of sulfur.

The Chena Plant currently utilizes a single baghouse to filter particulate from the flue gas streams of all four boilers. The optimal location for any future SCR would therefore be on the common flue gas duct immediately downstream of the existing baghouse.

The boilers at the Chena Plant are currently configured with an integral economizer attached directly to the exhaust flange of each boiler. The purpose of this economizer is to utilize waste heat in the flue gas to preheat water entering the boiler drum. This results in a significant reduction in flue gas temperature across the economizer. The 2016 source test data used by ADEC in their economic analysis indicated that typical full-load flue gas temperatures at the stack was approximately 310 °F. Stanley Consultants provided this information, along with other information relating to the flue gas system configuration, to a systems vendor BACT Process Systems for their review and input. BACT Process Systems was contacted as they had recent experience in the supply and installation of emissions control equipment (including a Dry Sorbent Injection System and SCR) at nearby Eielson Air Force Base (EAFB). The EAFB facility burns the same coal as the Chena plant in boilers of similar design. The response from BACT, based on information collected from one of their current catalyst suppliers, indicated that current SCR catalysts require a minimum of 350 °F to function effectively. This statement was also verified by a second SCR vendor. A representative of Fuel Tech, Inc. indicated that temperatures below 400 °F can significantly increase the required amount of catalyst. The representative also confirmed that the minimum flue gas temperature is between 350 °F and 365 °F. Information provided by both vendors can be found in Appendix A.

Other SCR configurations are utilized to allow the installation of an SCR into an existing flue gas system. The configuration that is most applicable to this scenario would be one that was recently utilized at Eielson Air Force Base in conjunction with the installation of the replacement boilers for Units 5 and 6. The design at Eielson relies on two separate economizers. The first economizer is integral to the boiler and is used to reduce the temperature of the flue gas leaving the boiler to approximately 500 °F. The flue gas is then treated with sodium bicarbonate to reduce sulfur emissions before it passes through the baghouse and the SCR. The second economizer is located after the SCR and is used to reduce the flue gas temperature to approximately 300 to 350 °F. This configuration works well for the Eielson facility because each flue gas system is separate from the other boilers and the equipment (boiler, sorbent injection, baghouse, SCR, and economizers) are in close proximity to each other. This configuration would not be possible at the Chena Plant due to the existing boiler enclosure building and the existing common flue duct tying the boilers together into the baghouse and the large distances between the boilers and the baghouse.

Given the constraints identified above, Stanley Consultants concludes that Selective Catalytic Reduction is not technically feasible at the Chena Plant. This is contrary to the conclusions reached by both ERM and ADEC.

Selective Non-Catalytic Reduction

Stanley Consultants has reviewed the information relating to SNCR systems in both the ERM and ADEC documents and is in general agreement with the technical information provided in each. Information relating to SNCRs was also solicited from BACT Process Systems. Their response, included as Appendix B, also supports the conclusion that SNCR systems appear to be technically feasible.

The actual performance of a SNCR system can vary significantly based on the actual flue gas flow, the flue gas conditions and constituents emitted from each boiler. Given the boiler's size, their stoker and moving grate combustion method, and their limited back-pass configuration, Stanley Consultants would recommend retaining a SNCR System and Equipment Supplier to perform an engineering study prior to the finalization of any BACT determination, revising the air permit to restrict NO_x emissions, or concluding that SNCR technology is a technically feasible solution. The study would generally include steps (a) through (d) as identified in Appendix B. The steps consist of an assessment of existing conditions and fuels and the development of a computational model of the boiler. The results of the study can be used to optimize furnace combustion conditions, select the preferred reagent (ammonia versus urea), locate reagent injection nozzles, and predict reagent consumption and system performance for inputs to a financial model and capital outlay of SNCR for comparative efforts to the age, condition, and expected longevity of the existing boilers.

Section 3

Discussion of SO_x Control Options

The original ERM BACT Analysis provided a limited discussion of Flue Gas Desulfurization (FGD) that focused generally on wet or dry type systems. While there is only one Wet FGD technology, there are several technologies that are considered to be “dry” or “semi-dry” FGD processes. Each of these technologies have benefits and limitations that should be individually considered to determine technical feasibility, on a site-specific basis. Additional information on specific types of dry FGD equipment was provided in December of 2017 as an addendum to the original report. This addendum discussed the technical merits of Spray Dryer/Absorbers (SDA) and Dry Sorbent Injection (DSI) in additional detail. The results of the technical evaluation presented in both the primary report and the addendum concluded that all three of the evaluated technologies (Wet FGD, SDA, and DSI) were technically feasible. The subsequent economic evaluation, however, eliminated each technology due to their evaluated cost effectiveness. Each technology was estimated to have costs that exceeded $20,000 per ton of SO_2 captured.

The ADEC BACT Determination was in general agreement with the rationale used by ERM to determine the technical feasibility of the three FGD systems evaluated. It also reached the same conclusions regarding the cost effectiveness of the Wet FGD and SDA technologies. Both systems were far too expensive when compared to the predicted reduction in emissions. The ADEC calculation of cost effectiveness for a DSI system, however, resulted in a significantly lower cost per ton of SO_2 removed. The conclusion reached by ADEC in their BACT Determination was that a DSI system was both technically feasible and cost effective, therefore DSI qualified as BACT.

Stanley Consultants was asked to review the BACT Analysis and BACT Determination and to provide technical input where necessary. We were also asked to review the economic analyses provided in both documents and to develop an independent estimate of capital (initial investment), operating, and maintenance (annualized) costs for a DSI system. Finally, we were asked to provide technical and economic information for a Circulating Dry Scrubber (CDS) FGD system. This was based on a recent determination by ADEC that the CDS technology has been successfully implemented as a FGD device in other industrial coal boilers, and therefore it must be included in the BACT analysis.

Wet Flue Gas Desulfurization and Spray Dryer Absorbers

Stanley Consultants reviewed both the BACT Analysis and the BACT Determination and agrees with the conclusion that the Wet FGD or SDA controls will not be cost effective and therefore are not BACT.

Circulating Dry Scrubbing

As previously stated, Aurora Energy recently received a request from ADEC to include Circulating Dry Scrubbing as a commercially available control technology in the BACT Analysis. The information in this section is structured to compare the CDS technology to a SDA system. The chemical process by which the sulfur is removed from the flue gas is the same in both technologies, however, there are several differences between the two systems that have significant impacts on the technical viability and cost effectiveness of each system.

Both the CDS and SDA technologies, for industrial coal fired applications, employ an alkaline reagent of calcium hydroxide, hydrated quicklime, and fly ash, which is collected from the combustion process. The calcium hydroxide reacts with Sulfur ioxide (SO_2) and sulfur trioxide (SO_3) of the flue gas to form calcium sulfite and calcium sulfate. The calcium sulfite and calcium sulfate, unreacted calcium hydroxide, and fly ash are collected downstream of the acid gas scrubbing process by a baghouse, and a considerable portion is "recycled," back to the scrubber to offset reagent costs by utilizing available unreacted alkalinity of the fly ash. The fly ash particles also serve to increase the available surface area for reactions to occur. Both processes also depend on the addition of water to humidify the flue gas. In general, the greater the humidification, the lower the alkalinity stoichiometry, which reduces reagent consumption. To prevent corrosion downstream of these scrubbers and promote the longevity of downstream equipment (namely fluework, particulate collection, and stack), the humidification is limited to operating above the saturation temperature, referred to as the approach temperature.

The method by which the flue gas stream is humidified is an area where the SDA and CDS scrubbing processes diverge.

In the SDA process, water for humidification is delivered as a portion of the lime and ash constituents. The water, lime, and ash slurries are pumped through recirculation loops and fed to an atomization feed system. The slurry that is fed to the atomizer is then atomized into small droplets which are dispersed in a passing flue gas stream inside an absorber or scrubber vessel. Once dispersed in the flue gas, a chemical reaction occurs, and the gas stream is scrubbed of the SO_2 and SO_3 pollutants. Since the slurry reagent is hydraulically conveyed by pumping, the SDA process can sometimes leverage existing infrastructure such as the particulate collection equipment. The ability to integrate a SDA system into an existing flue gas system limits the capital outlay necessary for a targeted level of compliance. The potential to leverage existing infrastructure is dependent on numerous factors such as existing equipment layout and condition, site spatial limitations, and original design parameters of the existing particulate collection equipment.

The humidification of the flue gas stream for a CDS scrubbing process is essentially decoupled from the hydrated lime and ash constituents. Water for gas humidification is mechanically atomized into the passing flue gas stream and the dry alkaline products are conveyed to the CDS vessel using air slide conveyors. Air slide conveyors utilize an air permeable fabric, which is stretched across a rectangular enclosure flow path, to aerate particulate material, and allow the force of gravity to covey the material down the sloped surface. The alkaline material and water injection (humidification) typically occurs after a venturi assembly that increases the velocity of the passing flue gas stream to establish a fluidized bed of alkaline material. As the flue gas passes through the bed of alkaline material, it is scrubbed of the SO_2 and SO_3. The use of air slides to convey the fly ash from the particulate collection device (typically a baghouse) back to the scrubber necessitates that the particulate collector (baghouse) be placed at higher elevations. This will ensure that the proper slope is established between the collector and the injection point on the absorber tower. It is technically challenging to take an existing particulate collector and elevate it, so CDS technologies are typically purchased with an absorber vessel, air slides, particulate collection device, and waste ash systems. This allows the integration of the required elevation differences and the steel and foundations necessary to accommodate the higher elevation construct. Due to the additional equipment, steel, and deep foundations necessary, these factors typically increase the capital outlay for a CDS technology.

Additional information on both SDA and CDS technology can be found in Chapter 34 of STEAM, Its Generation and Use, 42nd Edition, Babcock and Wilcox, Inc. Reference Figure 10 on Page 34-15 for an illustration of a typical SDA installation and Figure 17 on Page 34-21 for an illustration of a typical CDS installation.

The information above indicates that CDS and SDA technologies are similar in their nature and operation. However, the installation of a CDS frequently requires the installation of a new particulate collector, where the SDA system may not. The CDS equipment itself, along with the additional equipment needed for proper operation, will result in an initial (capital) cost that is significantly higher than an equivalent SDA system. Given that the ADEC BACT Determination has already established that a SDA system is not cost effective (Table 4-3, Page 12), it can therefore be concluded that the CDS system is also not cost effective, and therefore is not BACT.

Dry Sorbent Injection (DSI)

Stanley Consultants has reviewed the technical information provided in both the BACT Analysis and the BACT Determination relating to DSI systems. Based on our experience with DSI applications, we agree that DSI controls are technically feasible. Given the discrepancy in the evaluated cost effectiveness between the two reports, Aurora Energy retained Stanley Consultants to provide an independent estimation of the actual capital investment and annualized costs for a dry sorbent installation at the Chena Plant. The primary goal of this effort was to develop a site-specific cost estimate by identifying the costs to procure and install the specific equipment and components that are required for the Chena plant. Reference Section 4 of this report for additional information.

Section 4

Project Cost Estimates

Disclaimer

The information presented in this section was developed using a methodology intended to produce a result that represented the lowest reasonable cost for the project. The cost information provided herein is not a realistic estimate of actual project costs and should not be utilized for project budgeting purposes or other financial predictions.

Design Basis

The following data and assumptions were utilized to identify the system performance requirements and scope of supply for both the DSI equipment vendor and the construction contractor. Equipment and piping (internal to silo skirts and sorbent preparation building) costs for the DSI systems were developed by BACT Process Systems, Inc. BACT supplied the DSI system that was recently installed at Eielson AFB, and therefore was already familiar with this type of application. Additional information relating to the BACT scope of supply can be found in Appendix C. Balance of Plant (BOP) piping, electrical, and foundations were estimated by Stanley Consultants, as described below.

Boiler Performance and Flue Gas

The coal used at both the Eielson AFB and Chena Plants is supplied from the Usibelli Coal Mine in Healy, Alaska. Boiler heat input, flue gas flows, and uncontrolled SO_2 emissions rates for the Chena Plant were obtained from previous flue gas studies. The available coal data and the information provided in the studies was utilized to determine storage needs, equipment sizes, and required sorbent feed rates.

Dry Sorbent Unloading, Storage, Preparation, and Injection System

The BACT proposal includes the following equipment:

- Sorbent unloading equipment suitable for transporting sodium bicarbonate from a railcar to a bulk storage silo. This equipment includes unloading blowers, coolers, piping and piping components.

- Two bulk storage silos with a total storage capacity that are sufficient for three months of continuous full load operation.

- Sorbent transfer equipment for moving the sorbent from the bulk storage silos to the day bins located in a sorbent preparation building including transport blowers, coolers, and associated piping

- Sorbent mills for optimizing the particle size of the sorbent prior to injection into each boiler flue

- Sorbent injection equipment including filter receivers, airlock feeders, blowers, coolers, and piping up to the wall of the sorbent preparation building.

- All piping between the railcar unloading skid and the sorbent prep building.

- All piping inside the sorbent prep building.

- Sorbent injection lances

- Dedicated PLC's for the control of all equipment included in the proposal

- Engineering to facilitate the integration of the sorbent control system into the plant control system

- Computational Fluid Dynamics (CFD) of each flue to confirm predicted sorbent effectiveness

Additional BOP equipment, ancillary support systems, foundations that are required for the DSI system, but were not included in the BACT vendor proposal have been accounted for by Stanley Consultants in the cost estimate. This scope includes:

- Piping between the sorbent preparation building and the injection lance on each boiler's respective, outlet flue.

- Additional ductwork on Boiler 5 to increase sorbent resonance time prior to the baghouse

- Electrical feeds and equipment required to support the BACT vendor equipment (new feeds and equipment only, the suitability of the existing plant electrical system was not evaluated)

- Foundations

- Sorbent preparation building and interior structures

- Miscellaneous steel and supports

Equipment Layout

The cost estimate is based on the following approximate equipment locations:

- Unloading Equipment
  - North of Chena River
  - A rail spur adjacent and immediately northwest of the existing coal unloading building on the north side of Phillips Field Road
- Bulk Storage and Transfer Equipment
  - North of Chena River
  - Adjacent to the existing coal pile on the south side of Phillips Field Road.
- Sorbent Preparation Building
  - South of Chena River
  - Adjacent to the existing baghouse

See the sketch included as Appendix C for additional information on the proposed equipment locations and interconnecting piping.

General Assumptions

The estimated accuracy of this Opinion of Probable Costs is +50% and -15%. The approach used during the cost estimating effort was to make every reasonable assumption to simplify the project and reduce the estimated capital cost. Preliminary design activities, such as general arrangements and system integration evaluations were conducted to determine the essential project scope that would be required. Existing systems were assumed to have sufficient capacity to support the additional DSI equipment without modification. Existing foundations were utilized to estimate the cost of foundations for the new equipment, without consideration for recent code changes or review of recent geotechnical study results. Every effort was made to develop an estimate of the lowest realistic cost necessary to install DSI at the Chena Power Plant. This approach was utilized to reduce the downside uncertainty associated with the projected cost and to reinforce the conclusion that a DSI system is not a cost-effective emissions control alternative.

Given the approach outlined above, many potential design considerations that would typically add significant cost to any project were assumed not to be necessary. In general, if it was not apparent that a cost was essential to the completion of the project, it was omitted from the cost estimate. Design considerations that were intentionally undervalued or omitted from the estimate include, but are not limited to:

1. Hazmat abatement (asbestos, lead, PCB’s, soil remediation)
2. Subsurface Investigations (Geotechnical Report)
3. Existing soil conditions and impact on foundation requirements
4. Impacts of project on existing electrical system (capacity, redundancy, expansion requirements)
5. Structural capacity of existing buildings and steel structures
6. Seasonal work phasing / productivity
7. Expansion of plant utilities (air, cooling water, electrical, HVAC)

8. Rail spur engineering or construction. Existing spur was assumed available and appropriately configured for tank car staging, without primary rail operating disruptions.
9. Owner's costs, including owner's project management, owner's engineer, startup sorbent, spares, and permitting costs were excluded from this estimate.
10. Project costs related to taxes, duties, and tariffs.
11. Owners contingency

Stanley Consultants has provided cost estimates for several recent projects at various locations in the State of Alaska. Our experience to-date has been that the use of typical cost estimating resources (in this case, RS Means) will result in a cost estimate that is significantly below the costs that are actually incurred by the Owner. Installation costs used in this estimate were taken directly from RS Means. Rates were factored slightly upward to account for construction costs in interior Alaska.

All costs are expressed in January 2020 US dollars and a 14-month escalation prior to construction has been included.

Technical Methodology and Assumptions

The methodology utilized to develop project quantities along with the subsequent procurement and installation costs is detailed below. Several assumptions were made about the equipment requirements and BOP aspects concerning the installation of a dry sorbent injection system at the Chena Power Plant. The most significant assumptions, by discipline, are as follows.

General

Quantities of commodity products (piping and electrical cable) were based on distances scaled from Google Earth satellite imagery. Determined distances were then multiplied by an aggregate cost for material and labor obtained from RS Means Cost Estimation references. These costs include estimated commodity quantities along with any other components that are necessary for proper installation. The material and labor unit pricing for each of the components indicated were multiplied by a factor to obtain representative pricing in Fairbanks, Alaska. The summation of the aggregated costs, for each unit was divided by the measured distances to determine the unit costs presented. Factored RS Means data was also utilized to estimate equipment installation costs.

General craneage and forklift costs were also estimated based on RS Means costing data and multiplied by a factor to obtain representative pricing for the Fairbanks, AK location. Durations were estimated based on the anticipated project schedule. Cranage costs for pile driving operations were considered separately.

Civil / Structural

Stanley Consultants has assumed that all heavy structures or structures with a low tolerance for possible settlement will be founded on deep, pile foundations. This is based not only on the soil bearing capacities indicated by the rail unloading building foundation design drawings, but on the proximity of these structures to the river bank.

All light structures that can tolerate a minor amount of settlement were assumed to be founded on shallow, spread footings bearing on soils over-excavated and replaced with structural fill.

Unit costs for drilled caissons are based upon RS Means data for 24 inch diameter pipe piles driven in wet ground. Concrete fill will then be placed in the pipe above the soil plugs. Adjustments were made to the RS Means labor rates using blended wage rates for this project. It was assumed that a 150-ton crane with pile leads and pile hammer will be used. Civil excavation is assumed to proceed with heavy construction equipment.

Concrete is assumed to be batched at a batch plant with material costs based upon US rates. Concrete placement hours are based upon RS Means hours for manual placement adjusted by the productivity factor.

Structural steel was estimated by lineal feet for a pipe bridge, by square feet for platforms and by piece for the pipe supports.

Electrical

The existing master one-line diagram identified two 600A spare breakers on the 480V switchgear. It is assumed the existing electrical system has spare capacity to utilize these spare breakers. These spare breakers would each feed an outdoor motor control center (MCC) rated at 600A each. No modifications to the existing electrical infrastructure, no alternate power feeds, and no protective relay replacements were included in the electrical cost estimate. Note: modifications may be required but were not included herein.

It was assumed that conduit would be routed above grade using existing building columns or support steel. Cable tray may be used as space allows. Above grade routing of circuits is the most economical. New conduit support steel was not included in the cost estimate.

The only below grade electrical installation is for the bare copper ground grid and ground rods surrounding the new equipment and MCC locations and would connect to the existing ground grid in a few locations.

Mechanical

The facilities existing features have sufficient margin and correct configuration to be used to support the sorbent conveyance piping, which the vendor has indicated as 6" schedule 80 carbon steel pipe. Excessive ancillary steel for piping supports or to augment existing steel features has not been included in the cost estimate.

Piping and supports in the sorbent storage silos and sorbent preparation building were provided by the vendor in the pricing and was not estimated as part of the BOP cost estimate.

Instrumentation & Controls

The quote from the equipment vendor includes the majority of the instrumentation and controls scope. The cost estimate includes costs for miscellaneous materials and engineering services provided by the existing control system vendor to facilitate the integration of the DSI system controllers.

Equipment Performance, Sizing, and Pricing

Sorbent consumption numbers and equipment sizing were developed based on typical performance characteristics. These characteristics are typical of a flue gas system that operates at or near 500 °F and has sufficient duct length ahead of a baghouse to ensure at least 2 to 3 seconds of resonance time for the sorbent. The flue gas streams from the Chena boilers operate at significantly lower temperatures (300 to 350 °F). The potential reduction in sorbent performance due to the existing flue gas temperatures has not yet been evaluated. Adjustments to the maximum capture rate or sorbent feed rate may be determined to be necessary as the preliminary design develops. The quote obtained for the DSI system and equipment can be found in Appendix C.

Other equipment pricing is identified in the cost estimate in Appendix D. Equipment costs include an allowance for shipping, technical field supervision during erection and commissioning, and training.

Contractor Cost Assumptions

Project indirect costs include costs to manage, supervise, provide safety oversight/reporting, construction procurement, QA/QC, security, start-up and commissioning, housekeeping staff, and insurance requirements to support the project. These costs are listed at the bottom of the cost estimate summary sheet and are calculated as a percentage of the bare costs. The prime contractor indirect labor and labor burdens on prime contractor's labor can vary considerably from 10% to 60% of bare costs additional depending upon owner stipulated requirements and scope concerning the indirect costs listed.

Contractor profit was estimated at 10% for this cost estimate. In addition to the projects risk, profit also has a strong dependency on the owner's requirements concerning construction activities, competitiveness and other market conditions, and the availability of trades necessary to execute the work.

The cost estimate assumed that the prime contractor will self-perform all aspects of the work. Typically, prime contractors need to subcontract civil, electrical, and architectural work. Each of these subcontractors to the prime contractor have their own overhead and profit that is then marked up again by the prime contractor. No subcontract to the prime contractor mark-ups have been assumed in the cost estimate.

Owners Cost Assumptions

Project costs that are unrelated to the construction contract were also excluded from the cost estimate. These costs include administrative expenses, O&M mobilization and training, security surveillance, owner insurance during construction, and testing and commissioning. Proposed non-construction costs for the example projects were reviewed and converted to a value expressed as a percent of total construction cost. These values were then used as a guide for approximating non-construction costs for this project.

Opinion of Probable Cost

Based on the information above, the current minimum estimate of probable cost for a DSI system is as follows:

- Total Installed Cost: $20.6 MM
- Sorbent Cost: $550/Ton, Delivered

Sorbent pricing information provided by BACT in their proposal was supplied by a sorbent vendor based on data from the year 2000. Stanley Consultants is aware of sorbent pricing from other operators in the region, but we have not been given explicit permission to identify the price or the plant in question. The price identified above is our best estimate for current pricing based on the information that is available at the time of this report.

Appendix A

SCR Information

BACT PROCESS SYSTEMS, INC.

3345 N. ARLINGTON HEIGHTS RD. SUITE B
ARLINGTON HEIGHTS, IL 60004-1900
(847) 577-0950
FAX: (847) 577-6355
E-MAIL: bact_process@sbcglobal.net

November 15, 2018

Mr. John Solan, P.E.
Senior Mechanical Engineer
STANLEY CONSULTANTS
8000 S. Chester St., Suite 500
Centennial, CO 80112

RE: Aurora Energy NOx Control / BACT File No. 18113

Dear John,

Following our conversation of yesterday, I have talked to the technical personnel at Haldor Topsoe, a leading catalyst supplier.

Here are their comments for SCR:

A. Minimum temperature for Catalyst: 350°f.
B. 50% turndown is acceptable in the Reactor.
C. Catalyst will work at 800-850°f, they have a number of installations in coal fired boiler. However, they caution SO_2 level should be taken into account if the SCR is before economizer and dry injunction.

Regarding the SNCR, I am attaching two write-ups we prepared for incorporating SNCR into the coal fired boilers. I believe this may be useful to you in your investigation of this approach.

Please feel free to call me with any questions you may have.

Best regards,

BACT PROCESS SYSTEMS, INC.

N.S. ("Bala") Balakrishnan
President

From: Dale T. Pfaff
To: Solan, John
Cc: Reid Thomas
Subject: FW: Current Lower Operating Temp Limit for SCR Catalyst
Date: Tuesday, December 4, 2018 4:29:29 PM

John:

I apologize for the delay in this response. In discussing this with FTEK's SCR Group, the usual minimum temperature for catalyst is ~400 °F for a reasonable catalyst volume. If the temperature falls much below that, one has to consider reheating the flue gas. It may become more economical to heat the flue gas back up as opposed to buying additional catalyst. However SCR reactions will still occur down to 350-365 °F. 365 °F has been quoted as a cutoff by one of our catalyst suppliers.

Please let me know if this answers your question.

Dale Pfaff
Fuel Tech
(847) 504-6650

Begin forwarded message:

> **From:** "Solan, John" <SolanJohn@stanleygroup.com>
> **Date:** November 28, 2018 at 9:46:26 AM CST
> **To:** "Dale Pfaff (dpfaff@ftek.com)" <dpfaff@ftek.com>
> **Subject: Current Lower Operating Temp Limit for SCR Catalyst**
>
> Dale,
> Can you answer a very quick question for me? What is the current lower operating temperature limit for commercially available SCR catalyst?
> I need some documentation from a vendor for this BACT study that we are doing for Aurora Energy in Fairbanks.
>
> Thanks in advance,
> -John
>
> John Solan, P.E.*, Senior Mechanical Engineer
> **STANLEY**CONSULTANTS, 8000 S. Chester St., Suite 500, Centennial, CO 80112
> T: 303.649.7830 | stanleyconsultants.com
> * Registered in the States of North Carolina, Colorado, and Alaska

Appendix B

SNCR Information

BACT PROCESS SYSTEMS, INC.

3345 N. ARLINGTON HEIGHTS RD. SUITE E
ARLINGTON HEIGHTS, IL 60004-1900
(847) 577-0950
FAX: (847) 577-0355
E-MAIL: bact_process@sbcglobal.net

STEPS TO DESIGN SNCR IN EXISTING BOILER

(a) Visit the plant to inspect the boiler

(b) Review the following information:

  i. Boiler design drawings including grate and overfire air system arrangement
  ii. Coal analyses (all possible sources)
  iii. Performance predictions

(c) Estimate furnace exit gas temperature (FEGT) based on standard manufacturer's design curves.

(d) (Optional) Use computer modeling to determine the following furnace gas conditions:

  i. Temperature profiles:

    1. Along the length of the super heater inlet tubes
    2. In the cavity between the super heater and boiler bank

  ii. Gas flow profiles
  iii .Estimates of O2, CO and NO concentrations
  iv. Potential for changing furnace combustion conditions (over fire air flow and distribution, flue gas recirculation, etc) to reduce NO formation

(e) Design the Urea injection system including:

  i. Quantity of urea to be injection to meet expected control requirements including sufficient excess capacity
  ii. Number of spray nozzles
  iii. Location of spray nozzles
  iv. Nozzle size, arrangement (using Caldyn nozzles) and spray pattern

v. Expected performance at full and ¾ load

(f) Integrate the injection system design with the design of the urea delivery, storage and handling system

REVIEW AMMONIA INJUNCTION SYSTEM:

i. Quantity of ammonia to be injection in the cavity between the superheater and boiler bank to meet the expected control requirements and with sufficient excess capacity

ii. Number of spray nozzles
iii. Location of spray nozzles
iv. Nozzle size, arrangement (using Caldyn nozzles) and spray pattern
v. Expected performance at full and ¾ load
vi. Safety issues

i. Evaluate potential NO reduction techniques:

i. Review the modeling results (see (e)(iv) above
ii. Identify potential fuel and air system hardware changes (in any) and design, specify, fabricate components as appropriate
iii. Identify operational changes (if any) and incorporate into the testing as appropriate

j. Determine additional instrumentation and control system requirements
i. Furnace gas temperature measurements
ii. Ammonia slip monitors
iii. Other

2. Prior to Boiler Restart-up

a. Install urea handling and injection system

b. Install furnace wall penetrations for temperature profile measurements and subsequent urea injection trials

c. Install boiler wall penetrations for cavity temperature profile measurements and subsequent ammonia injection trials (if needed)

d. Install other boiler penetrations for temperature and gaseous measurements as needed

e. Install hardware changes from (1)(i) as appropriate

f. Install additional instrumentation (see(1)(j) above)

g. Conduct "cold boiler" testing
   i. Coal distribution onto the grate
   ii. Adjust fuel distributor settings as appropriate
   iii. Overfire airflow distribution and penetration

3. Engineering Activities during "10-Day" Testing Period

   a. Observe boiler operations following achieving steady and sustained boiler operations at or near full load

   b. Boiler gas temperature profile measurements
      i. Furnace exit along length of superheaters
      ii. Superheater outlet
      iii. Boiler bank outlet
      iv. Economizer outlet
      v. Airheater Outlet
      vi. Scrubber/ID fan outlet

   c. Determine the sensitivity of FEGT measurements with changes in boiler operations
      i. Using the "as-found" boiler firing configuration
      ii. Following operational adjustments(load, excess air, air and fuel distribution (refer to (2)(g) above), etac.)
      iii. Using the hardware changes identified in (2)(e) above
      iv. Determine the effects on furnace NO levels

   d. Establish the firing conditions that product the "best" FEGT profile with minimum NO formation for use with urea injection.

   e. Establish the firing conditions that produce the "best" temperature profile in the cavity with minimum NO formation for use with ammonia injection

   f. Conduct initial urea injection trials using (d) above
      i. Vary the urea Normalized Stoichiomeatric Ratio (NSR)
      ii. Vary the urea spray pattern between the injection nozzle matrix

   iii. Evaluate differing nozzle sizes and arrangements
   iv. Determine:
      1. Impacts on NO reduction
      2. Impacts on ammonia slip
      3. Effects on FEGT variations

g. Repeat (f) above with a second firing arrangement that achieves a different FEGT profile

h. Repeat (f) above with a third firing arrangement that achieves a different FEGT profile

i. Analyze and report the results of trials

4. If Emission Levels ARE Acceptable

   a. Select the best arrangement for urea SNCR from the tests conducted in (3)

   b. Operate the system over long-term (30 to 60 days)

   c. Prepare recommended operating guidelines

   d. Conduct boiler operating training session(s)

   e. Assist (as needed) with compliance tests

   f. Assist(as needed) with long term urea injection system operations and emission controls

5. If Emission Levels ARE NOT Acceptable:

   a. Conduct initial ammonia injection trials using (3)(e) above
      i. Vary the ammonia Normalized Stoichiometric ratio (NSR)
      ii. Vary the ammonia spray pattern between the injection nozzle matrix
      iii. Evaluate differing nozzle sizes and arrangements

      iv. Determine:
         1. Impacts on NO reduction
         2. Impacts on ammonia slip
         3. Effects of cavity temperature variations

   b. Analyze and report results of trials

6. If Emission Levels ARE Acceptable, see (3) above

7. If Emission Levels ARE NOT Acceptable:

   a. Determine the firing arrangement that produces the optional FEGT and cavity temperature for combined urea/ammonia SNCR operations from (3)(d)+(e) above

   b. Conduct initial urea/ammonia injection trials using (a) above
      i. Vary the ammonia Normalized Stoichiometric Ratio (NSR)
      ii. Vary the ammonia spray pattern between the injection nozzle matrix
      iii. Evaluate differing nozzle sizes and arrangements
      iv. Determine:
         1. Impacts on NO reduction
         2. Impacts on ammonia slip
         3. Effects of cavity temperature variations

   c. Analyze and report results of trials

8. If Emission Levels ARE Acceptable, see (4) above

BACT PROCESS SYSTEMS, INC.

3345 N. ARLINGTON HEIGHTS RD. SUITE E
ARLINGTON HEIGHTS, IL 60004-1900
(847) 577-0950
FAX: (847) 577-6355
E-MAIL: bact_process@sbcglobal.net

SNCR FACTS

REAGENT: UREA OR AMMONIA

NOx REDUCTION 30% - 50%

TEMPERATURE: NH3 = 1600 oF – 2000 oF

UREA = 1650 oF – 2100 oF

RESIDENCE TIME: .5 SECONDS

AMMONIA SLIP: 5-10 PPM

STORAGE UREA CONCENTRATION: 50% - 70%

Appendix C

DSI Information

BACT PROCESS SYSTEMS, INC.

3345 N. ARLINGTON HEIGHTS RD. SUITE B
ARLINGTON HEIGHTS, IL 60004-1900
(847) 577-0950
FAX: (847) 577-6355
E-MAIL: bact_process@sbcglobal.net

November 1, 2018

Mr. John Solan, P.E.
Senior Mechanical Engineer
Stanley Consultants
8000 S. Chester Street, Suite 500
Centennial, CO 80112

RE: DSI for Aurora Energy / BACT Proposal No. 1899-R1

Dear John,

We are revising our proposal in the light of your comments. The Emissions and sorbent usage from the boiler is based on recent information from you: on 0.39 lbs. of SO2/MBTU these calculations are based on using a weight ratio of 2.6 lbs. of sodium bicarbonate to 1 lb. of sulfur and a NSR of 1.3; Sulphur at .28%; Heating Volume of 7,600; 80% removal of SO2.

BOILER	MBTU/HR	S02 PPH	SODIUM BICARBONATE PPH
1	76	29.64	100
2	76	29.64	100
3	76	29.64	100
4	269	139.88	400
		TOTAL 228 PPH	700 PPH
			0.35 Tons/Hr.
	Per Month:	8.4 Tons/Day	252 Tons

Bicarbonate Storage

For four months; we need 756 Tons of sorbent
(2) Silos: 518 Tons capacity each
TOTAL CAPACITY = 1,036 Tons
Silo Size: Same as Eielsen

Cost of Sodium Bicarbonate = $123,480 per month; this is based on estimate by Solvay for year 2000 delivery: $250 plus, $240 freight.

Scope of Supply

1. (2) Bolted Storage Silos – 22' DIA x 100' tall with bin-vent level control and bin vibrators; capacity = 1,036 tons; storage silo complete.
2. (1) Rail car unloading and diverters to fill silos located 500' away; rate = 33,000 PPH, blower = 200 HP; installed spare; backup blower.
3. (3) Day bins with pneumatic conveying from storage silos. Conveying distance 1,000', 6,000 PPH capacity, blower = 200 HP; blowers are spared.
4. (3) Classifier mills; 1,000 PPH capacity, 75 HP total, connected HP (for 2). The 75 HP is the sum of the grinding motor, classifier motor, brakes, and VFD.

5.&6. (3) Filter receivers with conveying blowers. Milled material conveying material from mill to filter receivers. (2) Blowers 75 HP total; total connected.

7. (4) Injector sets to be installed on duct work.
8. (1) Dedicated compressor.
9. (1) NEMA 6 control panel with microprocessor.
10. Integration to the boiler control panel.
11. CFD modeling and programing.
12. All pneumatic piping up to the reagent building. All piping within the sorbent prep building by BACT. Pipe from the building wall for the 4 pipes leading to each stack by customer. Air coolers are provided to minimize puffing of the reagent.
13. Sorbent building and foundation by customer.

Budget Sell Price: $4,900,000
Freight: $ 200,000
F.O.B. Shipping Point
Taxes Extra

If you have any questions, please let me know.

Best regards,

BACT PROCESS SYSTEMS, INC.

N.S. ("Bala") Balakrishnan
President


Aurora Energy LLC
Chena CHP Plant
N
Sorbent Railcar Unloading Skid
Pipe & Power thru Utilidor (under road).
Sorbent Storage Silos
Unit 5 Injection
Sorbent Prep Enclosure
Unit 1 Injection
Unit 2 Injection
Unit 3 Injection
Google Earth
© 2018 Google
300 ft

Google Maps Fairbanks

Google Maps Fairbanks

Appendix D

DSI Opinion of Probable Cost

Stanley Consultants INC.

		Rev. 1	Job No.	28709.01.00	Page No.		1
			Subject	Aurora Energy Chena - Dry Sorbent Injection			
Computed by	J. Smith / S. Worcester/ D. Bacon	Date 2/8/2019		Opinion of Probable Cost			
Checked by	J. Solan	Date 2/8/2019					
Approved by	C. Spooner	Date 2/8/2019	Sheet No.	1	of		1

Item Description		Quantity: No. of Unit	Quantity: UOM	Unit Cost	Total Cost
Engineering Services					
Engineering services provided throughout the project to assist with BOP design, technical specifications, procurement, bid evaluation, and construction observation.		1	EA	$1,873,100.00	$1,873,100
Dry Sorbent Injection System Supply					
DSI	Includes Railcar offloading, long term storage silos, day storage silos, milling, metering and feed.	1	EA	$4,900,000.00	$4,900,000
DSI Installation	Field Installation	1	EA	$1,550,000.00	$1,550,000
DSI Equipment Freight	FOB jobsite	1	EA	$200,000.00	$200,000
Structural					
Silo Foundation		2	EA	$244,304.00	$488,608
Sorbent Building Substructure		1	EA	$247,047.00	$247,047
Sorbent Building Superstructure		1	EA	$183,067.00	$183,067
Sorbent Building Exterior Closure		1	EA	$160,334.00	$160,334
Roofing		1	EA	$12,149.00	$12,149
Railcar Unloading Skid Foundation		5	CY	$650.00	$3,250
Transfer Skid Enclosure Foundation		5	CY	$650.00	$3,250
MCC Foundation		4	CY	$650.00	$2,600
Pipe Bridge by Silos - Steel	coal yard front end loader drive under.	4	TONS	$9,000.00	$36,000
Pipe Bridge by Silos - Foundations		6	CY	$650.00	$3,900
Outside Pipe Supports - Steel		10.0	TONS	$9,000.00	$90,000
Outside Pipe Supports - Foundations		40	CY	$650.00	$26,000
Inside Pipe Supports - Steel		3.00	TONS	$9,000.00	$27,000
Ductwork	100' Feet of Ductwork for Residence Time prior to PJFF	12.50	TONS	$10,300.00	$128,750
Mechanical					
Unit 1 Aggregate Piping Cost: 6" Sch 80 Pipe/Fittings/Flanges/Supports - Sorbent Prep to Injection Location		300	LF	$300.00	$90,000
Unit 2 Aggregate Piping Cost: 6" Sch 80 Pipe/Fittings/Flanges/Supports - Sorbent Prep to Injection Location		310	LF	$300.00	$93,000
Unit 3 Aggregate Piping Cost: 6" Sch 80 Pipe/Fittings/Flanges/Supports - Sorbent Prep to Injection Location		280	LF	$300.00	$84,000
Unit 5 Aggregate Piping Cost: 6" Sch 80 Pipe/Flanges/Supports - Sorbent Prep to Injection Location		200	LF	$300.00	$60,000
Electrical					
480V MCC	Mtl & Labor	2	EA	$65,177.00	$130,354
480V Panelboard and Xfmr	Mtl & Labor	2	EA	$10,200.00	$20,400
Cable - 480V - MCC, Loads	Mtl & Labor	9000	LF	$14.83	$133,436
Conduit - RGS	Mtl & Labor	6800	LF	$20.26	$137,748
Cable Terminations (Mat'l)	480V Material & Labor	496	EA	$26.11	$12,950
Light Fixtures Interior/Exterior	Surface mounted LED light fixtures (Mtl & Labor)	20	EA	$1,561.00	$31,220
Ground Grid extension	Mtl & Labor	1050	LF	$13.43	$14,100
Instrumentation & Controls					
BOP DCS Aspects		1	EA	$76,428.00	$76,428
All Terrain Forklift	45' lift, 35' reach, 9000 lb. capacity	12	WK	$6,455.00	$77,460
Hydraulic Crane	80-ton	90	DY	$4,365.00	$392,850
				Furnish and Erection Subtotal	$9,415,901
MOBILIZATION / DEMOBILIZATION & MISC COSTS				8%	$753,272
PRIME CONTRACTOR INDIRECT LABOR				40%	$1,538,236
CONTRACTOR OH & LABOR BURDENS ON PRIME CONTRACTORS LABOR				15%	$1,412,385
EQUIPMENT & SMALL TOOLS				10%	$902,305
CONTINGENCY				15%	$2,103,315
PROFIT				10%	$1,402,210
BOND				2%	$350,552
				Total Construction Cost	$17,878,177
	Escalation Percent 4.00%	Periods 14		Escalation (Nov 2018 - January 2020)	$852,635
				PROBABLE EQUIPMENT & CONSTRUCTION COST	$18,731,000
				PROBABLE ENGINEERING, EQUIPMENT & CONSTRUCTION COST	**$20,604,000**

Note: All costs presented in this document are Stanley Consultants' opinions of probable project, construction, and/or operation and maintenance costs. This estimate of probable construction cost is based on our experience and represent our best judgment. We have no control over cost of labor, materials, equipment, contractor's methods, or over competitive bidding or market conditions. Therefore, we do not guarantee that proposals, bids, or actual construction costs will not vary from estimates of project costs, construction, and/or operation and maintenance costs presented. The costs identified are based on Means Building Construction Cost Data, Engineering News Record Construction Cost Index, and/or vendor quotes.

From:	David Fish
To:	Dec Air Comment
Subject:	Usibelli Coal Mine, Inc. Comments on Draft SIP
Date:	Friday, July 26, 2019 2:37:43 PM
Attachments:	UCM Comments on Draft SIP 07262019.pdf

To whom it may concern,

Attached are comments provided to the DEC from UCM on the draft State Implementation Plan for the Fairbanks North Star Borough Fine Particulate Nonattainment Area.

Sincerely,

David Fish
Environmental Manager

Aurora Energy, LLC
100 Cushman St., Suite 210 | Fairbanks, AK 99701-4674
Office 907-457-0230 | Fax 907-451-6543 | Cell 907-799-9464
dfish@usibelli.com

USIBELLI COAL MINE, INC.
Marketing ■ 100 Cushman Street, Suite 210 ■ Fairbanks, AK 99701
(907) 452-2625 ■ fax (907) 451-6543

July 26, 2019

c/o Cindy Heil
Division of Air Quality
ADEC
555 Cordova Street
Anchorage, AK 99501
dec.air.comment@alaska.gov

Subject: Usibelli Coal Mine, Inc.'s (UCM) Formal Comment to Proposed Regulation Changes Relating to Fine Particulate Matter ($PM_{2.5}$); Including New and Revised Air Quality Controls and State Implementation Plan (SIP).

The DEC released on May 14, 2019 for public review, the Serious Area State Implementation Plan (SIP) for the Fairbanks North Star Borough (FNSB) Fine Particulate ($PM_{2.5}$) Nonattainment Area (NAA). Public comments are due by 5:00 pm on July 26, 2019. Usibelli Coal Mine, Inc. (UCM) appreciates the opportunity to comment on the SIP and the collaborative effort with the Alaska Department of Environmental Conservation (ADEC) to provide a means to attain the $PM_{2.5}$ 24-hour standard that is sensitive to the economics of industries and the communities affected.

Per the Clean Air Act (CAA), the Serious SIP was supposed to be submitted on December 31, 2017 to describe the Best Available Control Measures (BACM) bringing the area into attainment by December 31, 2019. The 2016 $PM_{2.5}$ Implementation rule allows states to request a 5-year extension of the attainment date (i.e., December 31, 2024) as part of the Serious SIP if attainment is not anticipated by December 31, 2019. Within the 5-year attainment date extension request, the state could outline Most Stringent Measures (MSM) to be applied towards bringing the area into attainment by December 31, 2024. However, if a request is not accepted by the EPA and the area does not meet attainment by the Serious Area attainment date (December 31, 2019) then the Clean Air Act is prescriptive and requires a plan to reduce the concentration of $PM_{2.5}$ by five percent annually. A plan is to be submitted one year after the attainment date (i.e., December 31, 2020) with details on how a 5% annual reduction will be achieved. What has been communicated through the Serious SIP draft is that the most expeditious attainment date for the area is 2029.

Device Requirements

Issue: DEC is adopting emission rates for solid fuel heating devices and requirements that do not give all devices equal consideration. Installation of coal-fired heating devices are not allowed unless they are a listed device (18 AAC50.079). There are no standards available in the regulations for the determination of a qualifying coal-fired heating device. Certain devices are not given options for installation within the regulation. Non-pellet fueled wood-fired hydronic heaters, although may have EPA certification under Subpart QQQQ, are not allowed to be installed within the nonattainment area per 18 AAC 50.077 (b) & (c).

Request:

- Develop standards to qualify the installation of coal-fired heating units. Suggested standard should be consistent with 18 g/h emission rate for existing units or 0.10 lbs/MMBtu [heat input basis] whichever is greater.
- Allow the installation of non-pellet fueled wood-fired hydronic heaters provided they are EPA certified.

Background:

The DEC is adopting several different emission rates for solid fuel heating devices which does not give all devices an equal consideration. There are EPA standards for wood stoves and hydronic heaters; also alternative standards for cordwood fired hydronic heaters.[1] These standards should be adopted without alteration. Both wood stoves and pellet fired hydronic heaters emission rates in the SIP are consistent with the 40 CFR Part 60, Subpart QQQQ standard for wood heating devices. The standards are set by the EPA and apply to manufacturers of the wood heating devices. Any such device that is approved by the EPA should be allowed in the nonattainment area, this includes outdoor hydronic heaters. Existing residential and smaller commercial coal-fired devices are required to be removed by December of 2024 and new coal-fired devices are prohibited from installation within the nonattainment area.[2] Coal-fired devices currently installed can be subject to an in-use source test to demonstrate the device meets the standard of 18 g/h of total particulate matter. This standard should also be the criteria for new residential and smaller commercial coal-fired devices. The 18 g/h standard is consistent with 0.10 lbs/MMBtu (heat input) emission rate for a unit that is rated at 400,000 Btu/hr. The Titan II auger-fed coal boilers are rated at 440,000 Btu/hr (heat output) and have undergone testing through OMNI Test Labs; the same lab that derived emission rates for the DEC which are being used in the nonattainment area SIPs. The OMNI test conducted in 2011 demonstrated that auger-fed coal fired hydronic heaters are extremely efficient. Ranking among the lowest emission rates for units tested. Emission rates of auger-fed coal-fired hydronic heaters (0.027g/MJ; **0.06 lbs/MMBtu[heat output basis]**) were consistent with EPA Certified Woodstoves (0.041 g/MJ; **0.10 lbs/MMBtu [heat output basis]**).[3] The DEC is aware that more efficient heating is better for the nonattainment area situation regardless of heating device. Acceptable standards for the installation of coal-fired units should be included within the proposed regulations. There should not only be a standard for the existing units referenced in the regulations but also an achievable emission rate and standards for new coal-fired units. While there are provisions for the department's approval contingency, it does not provide a target emission rate for respective devices and fuels that are not EPA certified.

Best Available Control Technologies (BACT)

The proposed SIP considers BACT for the major sources; however, authorization of the BACT determination is not finalized through the EPA. With an impending date to install BACT four years from the date of reclassification (i.e., June 9, 2021), there doesn't seem to be time for any technological changes to the community of major sources. Although the state is trying to accommodate the deadline for BACT implementation through creative agreements (e.g., Fort Wainwright), the DEC alternatively could

---

[1] Federal Register, Vol. 80, No.50, Monday, March 16, 2015. Pg. 13672.
[2] Section 7.7.5.1.2 "Device Requirements – wood-fired and coal-fired standards", Draft Serious SIP.
[3] OMNI-Test Laboratories, Inc. 2011. Measurement of Space-Heating Emissions. Prepared for FNSB. Retrieved from https://cleanairfairbanks.files.wordpress.com/2012/02/omni-space-heating-study-fairbanks-draft-report-rev-4.pdf

provide justification that the implementation of BACT is both technologically and economically infeasible at this time. This option is available to the state through 40 CFR 51.1010 (3). The economically infeasible consideration is relevant due to the cost of implementation of sulfur controls on the major sources for its potential gain in $PM_{2.5}$ reduction (approx. $10 million for 1 $\mu g/m^3$ removed). A technologic infeasibility case could be considered on the basis that impending deadlines for BACT implementation is constrictive. The actual time it would take to design, build and implement sulfur controls for any facility cannot be accommodated in the time allotted. If either approach is accepted by the EPA, no further consideration would be necessary for BACT. UCM is also providing a justification for the use of a 0.25% coal-sulfur content as opposed to the 0.2% coal-sulfur content proposed by the DEC in the Serious SIP.

Technological Infeasibility

Issue: BACT determination for Fort Wainwright (FWA) Central Heat and Power Plant (CHPP) is not justifiable considering the DEC's options under the 2016 $PM_{2.5}$ Implementation Rule.

Request: The option to determine BACT on FWA CHPP for SO_2 emissions is technologically infeasible due to time constraints is within DEC's authority. As such, a demonstration asserting that condition should be made.

Background:

BACT determination for the Fort Wainwright (FWA) Central Heat and Power Plant (CHPP) is arguably not justifiable per the requirements proposed in the draft Serious SIP. The Army installation was given two choices; either to retire the FWA CHPP or install and operate Dry Sorbent Injection (DSI) pollution control on the coal-fired boilers. As indicated, FWA is conducting a National Environmental Policy Act (NEPA) analysis to evaluate replacing the industrial coal-fired boilers which may take 2.5-3 years for a Record of Decision (ROD) [e.g., 2021 or 2022]. Since a determination captured in a ROD would come after the required installation date for BACT (i.e., June 9, 2021), the DEC is requesting an enforceable agreement to be made prior to the final submittal of the SIP (i.e., late 2019/early 2020). The agreement would be part of a Compliance Order by Consent (COBC) setting a date for either decommissioning the plant or installation of pollution controls. Realistically, whether the ROD determined the plant was to be decommissioned, alternative heating was proposed, or a do-nothing option was considered, the timeline for implementation of the agreement could be realized after DEC's expeditious attainment date of 2029.

Based on 40 CFR 51.1010 (3), the state may make a demonstration that any measure identified is "not technologically or economically feasible to implement in whole or in part by the end of the tenth calendar year following the effective date of the designation of the area, and may eliminate such whole or partial measure from further consideration under this paragraph." Since it is established that BACT implementation is not possible by June 9, 2021, it would seem reasonable to consider the option as technologically infeasible.

Sulfur Content of Coal

Issue: Proposed BACT for coal-sulfur content of 0.2% will cut off access to tens of millions of tons of coal for UCM as well as pose a potential threat of fuel supply interruption for the coal fired power plants.

Request:

- Adopt a new standard of 0.25% based on semi-annual weighted averages of coal-sulfur content in shipments of coal within semi-annual periods corresponding to Facility Operating Report reporting periods.
- Include provisions or circumstances within the SIP when the imposed coal-sulfur limit can be relaxed.

Background:

The ADEC has proposed that Best Available Control Technology (BACT) for coal burning facilities in the nonattainment area is a coal-sulfur limit of 0.2% sulfur by weight. Usibelli Coal Mine (UCM) is the only source of commercial coal available to the coal-fired facilities within the Fairbanks North Star Borough fine particulate nonattainment area. The mine has limited ability to affect the sulfur content in the coal. There isn't a coal washing or segregating facility associated with UCM which could ensure a consistent coal-sulfur concentration. Current practice for providing low-sulfur coal to customers is identifying sulfur content of the resource through drilling and sampling efforts. However, no matter how much sampling is done, the ability to characterize the sulfur content of the coal actually mined is limited.

Within the millions of tons of coal resources available to UCM, there is a significant amount of coal with higher sulfur content than 0.2%; in fact, any limit proposed to the coal sulfur content is effectively cutting off access to tens of millions of tons of coal resources. As such, UCM proposes that the coal-sulfur limit be lowered to 0.25% on an as received basis (wet) as opposed to 0.2% as proposed by ADEC. The increase in coal-sulfur content will help with coal accessibility and availability over the next decade and still provides ADEC with a 37.5% reduction in the potential to emit based from the current limit of 0.4%.

The state was silent on how the measure was to be reported or considered within a regulatory context. The ADEC's standard permit condition for coal fired boilers (Standard Condition XIII) requires that the permittee report sulfur content of each shipment of fuel with the semi-annual Facility Operating Reports. UCM currently provides semi-annual reports to all customers which includes sulfur content of each shipment of coal along with the weighted average coal-sulfur content for the six-month period coinciding with the operating reports' reporting period. UCM proposes that the standard operating permit condition remain the same and that facilities continue to provide the state with the sulfur content of each shipment of fuel; in addition, the weighted average coal-sulfur content of the shipments received by the facility during the reporting period would be referenced in the operating report.

UCM would like the DEC to include circumstances when any imposed reduced coal-sulfur limit can be relaxed. Situations when relaxing the coal-sulfur limit will not impede attainment of the $PM_{2.5}$ standard should be considered when drafting the proposed regulations. As previously indicated, coal resources are effectively being cut off by the imposition of a reduced limit. An example when relaxing the coal-sulfur limit wouldn't impede attainment of the standard is if sulfur controls were acquired on a coal-fired facility. The state and the facility would, inevitably, work out an emission rate for the facility. The subsequent fuel-sulfur loading requirement would be established in order for the facility to meet their emission limit. If the fuel-sulfur loading requirement could be in excess of the coal-sulfur limit while still allowing the facility to meet the emission limit; that should qualify as a criteria to relax the limit. Another condition may be when the area comes into attainment with the $PM_{2.5}$ standard. Perhaps one of the aspects of a maintenance state implementation plan could be to remove or relax the imposed coal-sulfur limit on the basis that the impact from coal-sulfur is negligible to the area problem.

Major Source Economic Infeasibility Justification

Issue: The DEC has the option to demonstrate the economic infeasibility of SO_2 BACT for major sources within the nonattainment area under 40 CFR 51.1010 (3) based on cost effectiveness. The most cost effective value for operating BACT controls on the community of major sources to remove 1 µg/m^3 of $PM_{2.5}$ is $9,794,799 per year [See Table 7b].

Request:

- Define cost effectiveness as cost per 1 µg/m^3 of $PM_{2.5}$ for this exercise.
- Derive a cost per ton removed for each major source in the nonattainment area by adjusting operational load to represent actual SO_2 emissions in the spreadsheets for each facility provided within the appendices of the "Control Strategies" section of the draft serious SIP.
- Evaluate the cumulative annualized cost incurred by the community of major sources within the nonattainment area based on potential tons removed from implementing SO_2 BACT using actual emissions (instead of PTE).
- Correlate annualized cost of SO_2 BACT controls with results from the SO_2 Analysis section of the draft SIP (Section 7.8.12.5) to derive a cost/µg/m^3 mitigated from applying SO_2 control technologies.

Background:

Major stationary sources are a subgroup of emission sources that are given special consideration under nonattainment area provisions. Point sources with emissions greater than 70 tons per year of $PM_{2.5}$ or any individual precursor (NOx, SO_2, NH_3, VOCs) are evaluated for appropriate control. NOx and SO_2 were addressed on an emission unit specific basis in DEC's Best Available Control Technologies (BACT) determinations. The DEC's evaluation considered technical feasibility and estimates of emissions reductions to meet a defined emission limit. Operations at the facility's potentials to emit is used for the purpose of identifying a cost effectiveness for each technology in cost per ton removed.

The BACT analyses evaluate pollution control independent of the nonattainment area problem; it is simply triggered as a condition of an area defined as being in serious nonattainment of a pollutant standard. As described in the 2016 $PM_{2.5}$ Implementation Rule, the state can provide either a technologic or an economic infeasibility demonstration for control measures.[4] The argument must illustrate it is not technologically or economically feasible to implement the control measure by the end of the tenth calendar year (i.e., December 31, 2019 for the FNSB NAA) following the effective date of the designation of the area. UCM believes that there is enough evidence to substantiate that SO_2 controls on the community of major sources is economically infeasible.

<u>Economic Infeasibility Justification</u>

The DEC has determined BACT is comprised of sulfur controls for major stationary sources. The DEC has also determined that sulfur controls are economically infeasible for one major source, silent on infeasibility for another, and partially economically infeasible for a couple of major sources within the NAA.[5] Per regulation, DEC has the authority to demonstrate that any measure identified is economically infeasible.[6] It is within the DEC's authority to determine that BACT for sulfur control is economically

[4] 40 CFR 51.1010 (3)
[5] Section 7.7.8 of the draft Serious SIP
[6] 40 CFR 51.1010 (3)

infeasible for the community of major sources in the NAA based on cost effectiveness.[7] If cost effectiveness is defined as cost per µg/m^3 removed, there is a clear justification to eliminate sulfur control measures from the community of major sources. The most cost effective value for operating BACT controls on the community of major sources to remove 1 µg/m^3 of $PM_{2.5}$ is $9,794,799 per year [See Table 7b].

<u>Annualized Cost of BACT Implementation</u>

The DEC derived cost effectiveness value in cost per ton removed is established through the implementation of the BACT analysis. The DEC preferred BACT controls and cost effectiveness value are referenced in Section 7.7.8 of the SIP.[8] Dry Sorbent Injection (DSI) is selected for the coal fired boilers with an 80% reduction in SO_2 and ULSD is suggested for GVEA's North Pole Plant and Zehnder Facility with a 99.7% removal rate for SO_2. Based on the Potential to Emit (PTE) of each facility, the state derives a cost effectiveness value for the sources.

Annualized cost to implement BACT for the community of major sources are based on operating scenarios for both PTE and actual emissions (2013) [9] from the facilities. The results are illustrated in Table 6a and 6b. The cost effectiveness value (cost/ton removed) is multiplied by the amount of pollution removed (tons) to derive an annual cost for BACT for each facility. The total annualized cost is the sum of the cumulative annual operating cost for the controls on all the major sources in the NAA. The annualized costs do not include the cost of fuel switching for smaller diesel engines, backup generators and boilers that are found on the campuses of certain facilities (e.g., UAF, FWA). The total annualized BACT implementation cost to operate at the PTEs is $49,296,062; annualized cost considering actual emissions is $20,843,332 (See Tables below).

Table 6a: BACT Annualized Costs Based on Potential To Emit

Facility	BACT (SO_2 Control)	SO_2 Reduction	SO_2 Emissions PTE[3]	SO_2 Reduction[3]	Cost/ton removed [2,3]	Annualized Cost
Units		(%)	(tpy)	(tpy)	($)	($)
Chena Power Plant	DSI	80	1,004.0	803.0	$ 7,495	$ 6,018,485
FWA	DSI	80	1,168.5	934.8	$ 10,329	$ 9,655,331
NPP-EU1	ULSD	99.7	1,486.4	1,482.0	$ 9,139	$ 13,543,998
NPP-EU2	ULSD	99.7	1,356.1	1,352.0	$ 9,233	$ 12,483,016
UAF	DSI	80	242.5	194.0	$ 11,578	$ 2,246,132
Zender	ULSD	99.7	598.6	597.0	$ 8,960	$ 5,349,120
Notes: See Below.					Total Annualized Cost	$ 49,296,082

Table 6b: BACT Annualized Costs Based on Actual Emissions

Facility	BACT (SO_2 Control)	SO_2 Reduction	SO_2 Emissions (Actual)[1,3]	SO_2 Reduction	Cost/ton removed[4]	Annualized Cost
Units		(%)	(tpy)	(tpy)	($)	($)
Chena Power Plant	DSI	80	711.8	569.4	$ 8,960	$ 5,101,824
FWA	DSI	80	766.5	613.2	$ 11,235	$ 6,889,302
NPP-EU1	ULSD	99.7	142.3	141.9	$ 12,169	$ 1,726,454
NPP-EU2	ULSD	99.7	422.3	421.0	$ 9,453	$ 3,980,026
UAF	DSI	80	219.0	175.2	$ 11,578	$ 2,028,466
Zender	ULSD	99.7	73.0	72.8	$ 15,351	$ 1,117,261
Notes:					Total Annualized Cost	$ 20,843,332

1 - Table 7.6-9 "2013 SO2 Episodic vs. Annual Average Point Source Emissions (tons/day)"
2 - Sectoin 7.7.8 of SIP
3 - BACT Spreadsheets (May 2019) in SIP for Listed Facilities; adjusted AE emission factor of 0.472 lbs-SO2/MMBtu referenced in BACT Section of SIP.
4 - Cost/ton removed after adjusting operational load in BACT Spreadsheets (May 2019) to reflect actual emissions; AE emission factor of 0.472 lbs-SO_2/MMBtu

[7] 40 CFR 51.1010 (3)(ii)
[8] Appendix III.D.7.07 Control Strategies: https://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip/
[9] Table 7.6-9 "2013 SO2 Episodic vs. Annual Average Point Source Emission (tons/day)"[Draft Serious SIP]ADEC

Major Source SO_2 Control Cost Effectiveness: Cost per µg/m^3 $PM_{2.5}$ Removed

The DEC provided an SO_2 analysis using the 2019 projected baseline inventory. [10] The DEC determined that major stationary sources were found to contribute significantly to $PM_{2.5}$ concentrations at the State Office Building (SOB) and the monitor adjacent to the Borough building (NCORE) in downtown Fairbanks. The impact at the monitors were 1.79 µg/m^3 and 1.70 µg/m^3 respectively.[11] The impact at the Hurst Road and North Pole Elementary (NPE) monitors were 0.04 µg/m^3 and 0.10 µg/m^3 respectively.

Assuming that an 80% removal of the point source emissions of SO_2 would translate to an 80% reduction to the impact from major sources of sulfur-based $PM_{2.5}$ at the monitors, the amount of $PM_{2.5}$ reduced at the SOB, NCORE, Hurst Road, and NPE monitors would be 1.43 µg/m^3, 1.36 µg/m^3, 0.03 µg/m^3, and 0.08 µg/m^3 respectively. Based on the total annualized cost for BACT controls using actual emissions ($20,843,332) the cost effectiveness value in cost per µg/m^3 of $PM_{2.5}$ removed is at the best, $14,555,400 per µg/m^3 removed and at the worst $651,354,137 per µg/m^3 removed (Table 7a). If the alternative approach to the SO_2 design value contribution from major sources is considered then the cost effectiveness at best is $9,794,799 per µg/m^3 and at worst is $19,299,382 per µg/m^3 (Table 7b).

Ironically, the cost per µg/m^3 removed is less at the SOB and NCORE sites where the projected design value is in compliance with the standard. The projected design value provided by the DEC for 2019 meet attainment at the SOB and NCORE sites which are of 29.72 µg/m^3 and 29.01 µg/m^3 respectively[12]; the attainment standard is 35 µg/m^3. The 2019 design values at the Hurst Road and NPE monitors were 104.81 µg/m^3 and 36.48 µg/m^3, both clearly above the attainment standard of 35 µg/m^3. The impact from the major sources is less significant at the sites where the 2019 projected design value violates the standard.

Table 7a: Cost Effectiveness Based on Design Value Contribution SO_2 from Major Stationary Sources

Site	Design Value Base Year 2013[1]	Projeced Design Value Year 2019[1]	Major Source Sulfur-Based Particulate Contribution[2]	BACT Reduction (80% of Direct Emissions)	BACT Reduction / Design Value 2019	Annualized BACT Cost per ug/m^3 removed
Units	(ug/m^3)	(ug/m^3)	(ug/m^3)	(ug/m^3)	(%)	($)
State Office Building (SOB)	38.93	29.72	1.79	1.43	4.8%	$ 14,555,400
Fairbanks Borough Building (N	37.96	29.01	1.70	1.36	4.7%	$ 15,325,980
Hurst Road	131.63	104.81	0.04	0.03	0.0%	$ 651,354,137
North Pole Elementary (NPE)	45.3	36.48	0.10	0.08	0.2%	$ 260,541,655

Notes:
1 - Table 7.8-29 of Draft Serious SIP
2 - Table 7.8-26 of Draft Serious SIP

Table 7b: Cost Effectiveness Based on Alternative Approach to Design Value Contribution SO_2 from Major Stationary Sources

Site	Design Value Base Year 2013[1]	Projeced Design Value Year 2019[1]	Major Source Sulfur-Based Particulate Contribution[2]	BACT Reduction (80% of Direct Emissions)	BACT Reduction/Design Value 2019 x 100	Annualized BACT Cost per ug/m^3 removed
Units	(ug/m^3)	(ug/m^3)	(ug/m^3)	(ug/m^3)	(%)	($)
State Office Building (SOB)	38.93	29.72	2.66	2.13	7.2%	$ 9,794,799
Fairbanks Borough Building (N	37.96	29.01	2.53	2.02	7.0%	$ 10,298,089
Hurst Road	131.63	104.81	1.55	1.24	1.2%	$ 16,809,139
North Pole Elementary (NPE)	45.3	36.48	1.35	1.08	3.0%	$ 19,299,382

Notes:
1 - Table 7.8-29 of Draft Serious SIP
2 - Table 7.8-27 of Draft Serious SIP

[10] Section 7.8.12.5 of the draft Serious SIP
[11] Table 7.8-26. "Design value contribution from major stationary source SO_2".Draft Serious SIP.
[12] Table 7.8-29. "2019 FDV for Projected Baseline and Control Scenario Calculated against a 2013 Base year".

Fairbanks exceeds the fine particulate matter standard during winter months.[13] Control technology application on major stationary sources is permanent and transcends seasons. BACT for sulfur control on major sources is an annual solution to a wintertime problem. The application of SO_2 BACT is arguably an impractical effort. Where the pollutant concentration is either achieving or almost achieving the standard, the projected impact removed by application of BACT on the major sources is about 7% of the concentration. Since the standard is attained, removing 7% more of sulfur-based $PM_{2.5}$ for costs upward of $10 million dollars per μg/m^3 seems impractical. There is a mechanism allotted within the 2016 $PM_{2.5}$ Implementation Rule for the DEC to provide a detailed written justification for eliminating, from further consideration, potential control measures for SO_2 on the community of major stationary sources based on cost ineffectiveness.

As such, UCM supports an economic infeasibility determination for the application of BACT on all major stationary sources within the nonattainment area.

Conclusion

In summary, UCM is thankful to have the opportunity to comment on the Serious Area SIP and the proposed regulations. UCM's main concerns expressed within these comments are the application of a common standard for solid fuel burning devices, the application of a workable coal-sulfur limit as BACT for the coal-fired facilities, and an economic infeasibility justification for sulfur controls for the community of major sources in the NAA. Included below are summaries highlighting key points of UCM's comments:

- BACT requirement for coal facilities to meet coal-sulfur content of 0.2% is being contested. UCMs requests a modified BACT requirement to 0.25% coal-sulfur (as received) evaluated on a six-month weighted average using UCM analyses for each shipment.
- UCM is encouraging the DEC to include provisions or circumstances within the SIP when the imposed coal-sulfur limit can be relaxed without impact to the nonattainment area. As indicated, coal resources are effectively being cut off by the imposition of a reduced limit.
- A demonstration asserting that it is technologically infeasible to install BACT for SO_2 on the FWA CHPP due to time constraints is within the DEC's authority under the provisions of the 2016 $PM_{2.5}$ Implementation Rule and should be considered.
- UCM supports an economic infeasibility determination for the community of major sources based on the cost ineffectiveness of sulfur control technology in removing 1 μg/m^3 of sulfur-based $PM_{2.5}$ from major source SO_2 contribution.
- Solid fuel burning devices are not treated equally within the Serious Area SIP. A proposition for a common emission standard for those units that do not have EPA certification or standard to meet is encouraged. Those units with EPA standards should be allowed to operate within the NAA. Also, inclusion of emission standards and criteria for coal-fired home heating devices within the regulation is encouraged

[13] Section 7.8.6 of the Draft Serious SIP

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July 26, 2019

c/o Cindy Heil
Division of Air Quality
ADEC
555 Cordova Street
Anchorage, AK 99501
dec.air.comment@alaska.gov

Subject: Usibelli Coal Mine, Inc.'s (UCM) Formal Comment to Proposed Regulation Changes Relating to Fine Particulate Matter ($PM_{2.5}$); Including New and Revised Air Quality Controls and State Implementation Plan (SIP).

The DEC released on May 14, 2019 for public review, the Serious Area State Implementation Plan (SIP) for the Fairbanks North Star Borough (FNSB) Fine Particulate ($PM_{2.5}$) Nonattainment Area (NAA). Public comments are due by 5:00 pm on July 26, 2019. Usibelli Coal Mine, Inc. (UCM) appreciates the opportunity to comment on the SIP and the collaborative effort with the Alaska Department of Environmental Conservation (ADEC) to provide a means to attain the $PM_{2.5}$ 24-hour standard that is sensitive to the economics of industries and the communities affected.

Per the Clean Air Act (CAA), the Serious SIP was supposed to be submitted on December 31, 2017 to describe the Best Available Control Measures (BACM) bringing the area into attainment by December 31, 2019. The 2016 $PM_{2.5}$ Implementation rule allows states to request a 5-year extension of the attainment date (i.e., December 31, 2024) as part of the Serious SIP if attainment is not anticipated by December 31, 2019. Within the 5-year attainment date extension request, the state could outline Most Stringent Measures (MSM) to be applied towards bringing the area into attainment by December 31, 2024. However, if a request is not accepted by the EPA and the area does not meet attainment by the Serious Area attainment date (December 31, 2019) then the Clean Air Act is prescriptive and requires a plan to reduce the concentration of $PM_{2.5}$ by five percent annually. A plan is to be submitted one year after the attainment date (i.e., December 31, 2020) with details on how a 5% annual reduction will be achieved. What has been communicated through the Serious SIP draft is that the most expeditious attainment date for the area is 2029.

Device Requirements

Issue: DEC is adopting emission rates for solid fuel heating devices and requirements that do not give all devices equal consideration. Installation of coal-fired heating devices are not allowed unless they are a listed device (18 AAC50.079). There are no standards available in the regulations for the determination of a qualifying coal-fired heating device. Certain devices are not given options for installation within the regulation. Non-pellet fueled wood-fired hydronic heaters, although may have EPA certification under Subpart QQQQ, are not allowed to be installed within the nonattainment area per 18 AAC 50.077 (b) & (c).

Request:

- Develop standards to qualify the installation of coal-fired heating units. Suggested standard should be consistent with 18 g/h emission rate for existing units or 0.10 lbs/MMBtu [heat input basis] whichever is greater.
- Allow the installation of non-pellet fueled wood-fired hydronic heaters provided they are EPA certified.

Background:

The DEC is adopting several different emission rates for solid fuel heating devices which does not give all devices an equal consideration. There are EPA standards for wood stoves and hydronic heaters; also alternative standards for cordwood fired hydronic heaters.[1] These standards should be adopted without alteration. Both wood stoves and pellet fired hydronic heaters emission rates in the SIP are consistent with the 40 CFR Part 60, Subpart QQQQ standard for wood heating devices. The standards are set by the EPA and apply to manufacturers of the wood heating devices. Any such device that is approved by the EPA should be allowed in the nonattainment area, this includes outdoor hydronic heaters. Existing residential and smaller commercial coal-fired devices are required to be removed by December of 2024 and new coal-fired devices are prohibited from installation within the nonattainment area.[2] Coal-fired devices currently installed can be subject to an in-use source test to demonstrate the device meets the standard of 18 g/h of total particulate matter. This standard should also be the criteria for new residential and smaller commercial coal-fired devices. The 18 g/h standard is consistent with 0.10 lbs/MMBtu (heat input) emission rate for a unit that is rated at 400,000 Btu/hr. The Titan II auger-fed coal boilers are rated at 440,000 Btu/hr (heat output) and have undergone testing through OMNI Test Labs; the same lab that derived emission rates for the DEC which are being used in the nonattainment area SIPs. The OMNI test conducted in 2011 demonstrated that auger-fed coal fired hydronic heaters are extremely efficient. Ranking among the lowest emission rates for units tested. Emission rates of auger-fed coal-fired hydronic heaters (0.027g/MJ; **0.06 lbs/MMBtu[heat output basis]**) were consistent with EPA Certified Woodstoves (0.041 g/MJ; **0.10 lbs/MMBtu [heat output basis]**).[3] The DEC is aware that more efficient heating is better for the nonattainment area situation regardless of heating device. Acceptable standards for the installation of coal-fired units should be included within the proposed regulations. There should not only be a standard for the existing units referenced in the regulations but also an achievable emission rate and standards for new coal-fired units. While there are provisions for the department's approval contingency, it does not provide a target emission rate for respective devices and fuels that are not EPA certified.

Best Available Control Technologies (BACT)

The proposed SIP considers BACT for the major sources; however, authorization of the BACT determination is not finalized through the EPA. With an impending date to install BACT four years from the date of reclassification (i.e., June 9, 2021), there doesn't seem to be time for any technological changes to the community of major sources. Although the state is trying to accommodate the deadline for BACT implementation through creative agreements (e.g., Fort Wainwright), the DEC alternatively could

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[1] Federal Register, Vol. 80, No.50, Monday, March 16, 2015. Pg. 13672.
[2] Section 7.7.5.1.2 "Device Requirements – wood-fired and coal-fired standards", Draft Serious SIP.
[3] OMNI-Test Laboratories, Inc. 2011. Measurement of Space-Heating Emissions. Prepared for FNSB. Retrieved from https://cleanairfairbanks.files.wordpress.com/2012/02/omni-space-heating-study-fairbanks-draft-report-rev-4.pdf

provide justification that the implementation of BACT is both technologically and economically infeasible at this time. This option is available to the state through 40 CFR 51.1010 (3). The economically infeasible consideration is relevant due to the cost of implementation of sulfur controls on the major sources for its potential gain in $PM_{2.5}$ reduction (approx. $10 million for 1 µg/$m^3$ removed). A technologic infeasibility case could be considered on the basis that impending deadlines for BACT implementation is constrictive. The actual time it would take to design, build and implement sulfur controls for any facility cannot be accommodated in the time allotted. If either approach is accepted by the EPA, no further consideration would be necessary for BACT. UCM is also providing a justification for the use of a 0.25% coal-sulfur content as opposed to the 0.2% coal-sulfur content proposed by the DEC in the Serious SIP.

Technological Infeasibility

Issue: BACT determination for Fort Wainwright (FWA) Central Heat and Power Plant (CHPP) is not justifiable considering the DEC's options under the 2016 $PM_{2.5}$ Implementation Rule.

Request: The option to determine BACT on FWA CHPP for SO_2 emissions is technologically infeasible due to time constraints is within DEC's authority. As such, a demonstration asserting that condition should be made.

Background:

BACT determination for the Fort Wainwright (FWA) Central Heat and Power Plant (CHPP) is arguably not justifiable per the requirements proposed in the draft Serious SIP. The Army installation was given two choices; either to retire the FWA CHPP or install and operate Dry Sorbent Injection (DSI) pollution control on the coal-fired boilers. As indicated, FWA is conducting a National Environmental Policy Act (NEPA) analysis to evaluate replacing the industrial coal-fired boilers which may take 2.5-3 years for a Record of Decision (ROD) [e.g., 2021 or 2022]. Since a determination captured in a ROD would come after the required installation date for BACT (i.e., June 9, 2021), the DEC is requesting an enforceable agreement to be made prior to the final submittal of the SIP (i.e., late 2019/early 2020). The agreement would be part of a Compliance Order by Consent (COBC) setting a date for either decommissioning the plant or installation of pollution controls. Realistically, whether the ROD determined the plant was to be decommissioned, alternative heating was proposed, or a do-nothing option was considered, the timeline for implementation of the agreement could be realized after DEC's expeditious attainment date of 2029.

Based on 40 CFR 51.1010 (3), the state may make a demonstration that any measure identified is "not technologically or economically feasible to implement in whole or in part by the end of the tenth calendar year following the effective date of the designation of the area, and may eliminate such whole or partial measure from further consideration under this paragraph." Since it is established that BACT implementation is not possible by June 9, 2021, it would seem reasonable to consider the option as technologically infeasible.

Sulfur Content of Coal

Issue: Proposed BACT for coal-sulfur content of 0.2% will cut off access to tens of millions of tons of coal for UCM as well as pose a potential threat of fuel supply interruption for the coal fired power plants.

Request:

- Adopt a new standard of 0.25% based on semi-annual weighted averages of coal-sulfur content in shipments of coal within semi-annual periods corresponding to Facility Operating Report reporting periods.
- Include provisions or circumstances within the SIP when the imposed coal-sulfur limit can be relaxed.

Background:

The ADEC has proposed that Best Available Control Technology (BACT) for coal burning facilities in the nonattainment area is a coal-sulfur limit of 0.2% sulfur by weight. Usibelli Coal Mine (UCM) is the only source of commercial coal available to the coal-fired facilities within the Fairbanks North Star Borough fine particulate nonattainment area. The mine has limited ability to affect the sulfur content in the coal. There isn't a coal washing or segregating facility associated with UCM which could ensure a consistent coal-sulfur concentration. Current practice for providing low-sulfur coal to customers is identifying sulfur content of the resource through drilling and sampling efforts. However, no matter how much sampling is done, the ability to characterize the sulfur content of the coal actually mined is limited.

Within the millions of tons of coal resources available to UCM, there is a significant amount of coal with higher sulfur content than 0.2%; in fact, any limit proposed to the coal sulfur content is effectively cutting off access to tens of millions of tons of coal resources. As such, UCM proposes that the coal-sulfur limit be lowered to 0.25% on an as received basis (wet) as opposed to 0.2% as proposed by ADEC. The increase in coal-sulfur content will help with coal accessibility and availability over the next decade and still provides ADEC with a 37.5% reduction in the potential to emit based from the current limit of 0.4%.

The state was silent on how the measure was to be reported or considered within a regulatory context. The ADEC's standard permit condition for coal fired boilers (Standard Condition XIII) requires that the permittee report sulfur content of each shipment of fuel with the semi-annual Facility Operating Reports. UCM currently provides semi-annual reports to all customers which includes sulfur content of each shipment of coal along with the weighted average coal-sulfur content for the six-month period coinciding with the operating reports' reporting period. UCM proposes that the standard operating permit condition remain the same and that facilities continue to provide the state with the sulfur content of each shipment of fuel; in addition, the weighted average coal-sulfur content of the shipments received by the facility during the reporting period would be referenced in the operating report.

UCM would like the DEC to include circumstances when any imposed reduced coal-sulfur limit can be relaxed. Situations when relaxing the coal-sulfur limit will not impede attainment of the $PM_{2.5}$ standard should be considered when drafting the proposed regulations. As previously indicated, coal resources are effectively being cut off by the imposition of a reduced limit. An example when relaxing the coal-sulfur limit wouldn't impede attainment of the standard is if sulfur controls were acquired on a coal-fired facility. The state and the facility would, inevitably, work out an emission rate for the facility. The subsequent fuel-sulfur loading requirement would be established in order for the facility to meet their emission limit. If the fuel-sulfur loading requirement could be in excess of the coal-sulfur limit while still allowing the facility to meet the emission limit; that should qualify as a criteria to relax the limit. Another condition may be when the area comes into attainment with the $PM_{2.5}$ standard. Perhaps one of the aspects of a maintenance state implementation plan could be to remove or relax the imposed coal-sulfur limit on the basis that the impact from coal-sulfur is negligible to the area problem.

Major Source Economic Infeasibility Justification

Issue: The DEC has the option to demonstrate the economic infeasibility of SO_2 BACT for major sources within the nonattainment area under 40 CFR 51.1010 (3) based on cost effectiveness. The most cost effective value for operating BACT controls on the community of major sources to remove 1 $\mu g/m^3$ of $PM_{2.5}$ is $9,794,799 per year [See Table 7b].

Request:

- Define cost effectiveness as cost per 1 $\mu g/m^3$ of $PM_{2.5}$ for this exercise.
- Derive a cost per ton removed for each major source in the nonattainment area by adjusting operational load to represent actual SO_2 emissions in the spreadsheets for each facility provided within the appendices of the "Control Strategies" section of the draft serious SIP.
- Evaluate the cumulative annualized cost incurred by the community of major sources within the nonattainment area based on potential tons removed from implementing SO_2 BACT using actual emissions (instead of PTE).
- Correlate annualized cost of SO_2 BACT controls with results from the SO_2 Analysis section of the draft SIP (Section 7.8.12.5) to derive a cost/$\mu g/m^3$ mitigated from applying SO_2 control technologies.

Background:

Major stationary sources are a subgroup of emission sources that are given special consideration under nonattainment area provisions. Point sources with emissions greater than 70 tons per year of $PM_{2.5}$ or any individual precursor (NOx, SO_2, NH_3, VOCs) are evaluated for appropriate control. NOx and SO_2 were addressed on an emission unit specific basis in DEC's Best Available Control Technologies (BACT) determinations. The DEC's evaluation considered technical feasibility and estimates of emissions reductions to meet a defined emission limit. Operations at the facility's potentials to emit is used for the purpose of identifying a cost effectiveness for each technology in cost per ton removed.

The BACT analyses evaluate pollution control independent of the nonattainment area problem; it is simply triggered as a condition of an area defined as being in serious nonattainment of a pollutant standard. As described in the 2016 $PM_{2.5}$ Implementation Rule, the state can provide either a technologic or an economic infeasibility demonstration for control measures.[4] The argument must illustrate it is not technologically or economically feasible to implement the control measure by the end of the tenth calendar year (i.e., December 31, 2019 for the FNSB NAA) following the effective date of the designation of the area. UCM believes that there is enough evidence to substantiate that SO_2 controls on the community of major sources is economically infeasible.

<u>Economic Infeasibility Justification</u>

The DEC has determined BACT is comprised of sulfur controls for major stationary sources. The DEC has also determined that sulfur controls are economically infeasible for one major source, silent on infeasibility for another, and partially economically infeasible for a couple of major sources within the NAA.[5] Per regulation, DEC has the authority to demonstrate that any measure identified is economically infeasible.[6] It is within the DEC's authority to determine that BACT for sulfur control is economically

[4] 40 CFR 51.1010 (3)
[5] Section 7.7.8 of the draft Serious SIP
[6] 40 CFR 51.1010 (3)

infeasible for the community of major sources in the NAA based on cost effectiveness.[7] If cost effectiveness is defined as cost per µg/m^3 removed, there is a clear justification to eliminate sulfur control measures from the community of major sources. The most cost effective value for operating BACT controls on the community of major sources to remove 1 µg/m^3 of $PM_{2.5}$ is $9,794,799 per year [See Table 7b].

<u>Annualized Cost of BACT Implementation</u>

The DEC derived cost effectiveness value in cost per ton removed is established through the implementation of the BACT analysis. The DEC preferred BACT controls and cost effectiveness value are referenced in Section 7.7.8 of the SIP.[8] Dry Sorbent Injection (DSI) is selected for the coal fired boilers with an 80% reduction in SO_2 and ULSD is suggested for GVEA's North Pole Plant and Zehnder Facility with a 99.7% removal rate for SO_2. Based on the Potential to Emit (PTE) of each facility, the state derives a cost effectiveness value for the sources.

Annualized cost to implement BACT for the community of major sources are based on operating scenarios for both PTE and actual emissions (2013) [9] from the facilities. The results are illustrated in Table 6a and 6b. The cost effectiveness value (cost/ton removed) is multiplied by the amount of pollution removed (tons) to derive an annual cost for BACT for each facility. The total annualized cost is the sum of the cumulative annual operating cost for the controls on all the major sources in the NAA. The annualized costs do not include the cost of fuel switching for smaller diesel engines, backup generators and boilers that are found on the campuses of certain facilities (e.g., UAF, FWA). The total annualized BACT implementation cost to operate at the PTEs is $49,296,062; annualized cost considering actual emissions is $20,843,332 (See Tables below).

Table 6a: BACT Annualized Costs Based on Potential To Emit

Facility	BACT (SO_2 Control)	SO_2 Reduction	SO_2 Emissions PTE[3]	SO_2 Reduction[3]	Cost/ton removed [2,3]	Annualized Cost
Units		(%)	(tpy)	(tpy)	($)	($)
Chena Power Plant	DSI	80	1,004.0	803.0	$ 7,495	$ 6,018,485
FWA	DSI	80	1,168.5	934.8	$ 10,329	$ 9,655,331
NPP-EU1	ULSD	99.7	1,486.4	1,482.0	$ 9,139	$ 13,543,998
NPP-EU2	ULSD	99.7	1,356.1	1,352.0	$ 9,233	$ 12,483,016
UAF	DSI	80	242.5	194.0	$ 11,578	$ 2,246,132
Zender	ULSD	99.7	598.6	597.0	$ 8,960	$ 5,349,120
Notes: See Below.					Total Annualized Cost	$ 49,296,082

Table 6b: BACT Annualized Costs Based on Actual Emissions

Facility	BACT (SO_2 Control)	SO_2 Reduction	SO_2 Emissions (Actual)[1,3]	SO_2 Reduction	Cost/ton removed[4]	Annualized Cost
Units		(%)	(tpy)	(tpy)	($)	($)
Chena Power Plant	DSI	80	711.8	569.4	$ 8,960	$ 5,101,824
FWA	DSI	80	766.5	613.2	$ 11,235	$ 6,889,302
NPP-EU1	ULSD	99.7	142.3	141.9	$ 12,169	$ 1,726,454
NPP-EU2	ULSD	99.7	422.3	421.0	$ 9,453	$ 3,980,026
UAF	DSI	80	219.0	175.2	$ 11,578	$ 2,028,466
Zender	ULSD	99.7	73.0	72.8	$ 15,351	$ 1,117,261
Notes:					Total Annualized Cost	$ 20,843,332

1 - Table 7.6-9 "2013 SO2 Episodic vs. Annual Average Point Source Emissions (tons/day)"
2 - Sectoin 7.7.8 of SIP
3 - BACT Spreadsheets (May 2019) in SIP for Listed Facilities; adjusted AE emission factor of 0.472 lbs-SO2/MMBtu referenced in BACT Section of SIP.
4 - Cost/ton removed after adjusting operational load in BACT Spreadsheets (May 2019) to reflect actual emissions; AE emission factor of 0.472 lbs-SO_2/MMBtu

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[7] 40 CFR 51.1010 (3)(ii)
[8] Appendix III.D.7.07 Control Strategies: https://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip/
[9] Table 7.6-9 "2013 SO2 Episodic vs. Annual Average Point Source Emission (tons/day)"[Draft Serious SIP]ADEC

Major Source SO_2 Control Cost Effectiveness: Cost per µg/m^3 $PM_{2.5}$ Removed

The DEC provided an SO_2 analysis using the 2019 projected baseline inventory.[10] The DEC determined that major stationary sources were found to contribute significantly to $PM_{2.5}$ concentrations at the State Office Building (SOB) and the monitor adjacent to the Borough building (NCORE) in downtown Fairbanks. The impact at the monitors were 1.79 µg/m^3 and 1.70 µg/m^3 respectively.[11] The impact at the Hurst Road and North Pole Elementary (NPE) monitors were 0.04 µg/m^3 and 0.10 µg/m^3 respectively.

Assuming that an 80% removal of the point source emissions of SO_2 would translate to an 80% reduction to the impact from major sources of sulfur-based $PM_{2.5}$ at the monitors, the amount of $PM_{2.5}$ reduced at the SOB, NCORE, Hurst Road, and NPE monitors would be 1.43 µg/m^3, 1.36 µg/m^3, 0.03 µg/m^3, and 0.08 µg/m^3 respectively. Based on the total annualized cost for BACT controls using actual emissions ($20,843,332) the cost effectiveness value in cost per µg/m^3 of $PM_{2.5}$ removed is at the best, $14,555,400 per µg/m^3 removed and at the worst $651,354,137 per µg/m^3 removed (Table 7a). If the alternative approach to the SO_2 design value contribution from major sources is considered then the cost effectiveness at best is $9,794,799 per µg/m^3 and at worst is $19,299,382 per µg/m^3 (Table 7b).

Ironically, the cost per µg/m^3 removed is less at the SOB and NCORE sites where the projected design value is in compliance with the standard. The projected design value provided by the DEC for 2019 meet attainment at the SOB and NCORE sites which are of 29.72 µg/m^3 and 29.01 µg/m^3 respectively[12]; the attainment standard is 35 µg/m^3. The 2019 design values at the Hurst Road and NPE monitors were 104.81 µg/m^3 and 36.48 µg/m^3, both clearly above the attainment standard of 35 µg/m^3. The impact from the major sources is less significant at the sites where the 2019 projected design value violates the standard.

Table 7a: Cost Effectiveness Based on Design Value Contribution SO_2 from Major Stationary Sources

Site	Design Value Base Year 2013[1]	Projeced Design Value Year 2019[1]	Major Source Sulfur-Based Particulate Contribution[2]	BACT Reduction (80% of Direct Emissions)	BACT Reduction / Design Value 2019	Annualized BACT Cost per ug/m^3 removed
Units	(ug/m^3)	(ug/m^3)	(ug/m^3)	(ug/m^3)	(%)	($)
State Office Building (SOB)	38.93	29.72	1.79	1.43	4.8%	$ 14,555,400
Fairbanks Borough Building (N	37.96	29.01	1.70	1.36	4.7%	$ 15,325,980
Hurst Road	131.63	104.81	0.04	0.03	0.0%	$ 651,354,137
North Pole Elementary (NPE)	45.3	36.48	0.10	0.08	0.2%	$ 260,541,655

Notes:
1 - Table 7.8-29 of Draft Serious SIP
2 - Table 7.8-26 of Draft Serious SIP

Table 7b: Cost Effectiveness Based on Alternative Approach to Design Value Contribution SO_2 from Major Stationary Sources

Site	Design Value Base Year 2013[1]	Projeced Design Value Year 2019[1]	Major Source Sulfur-Based Particulate Contribution[2]	BACT Reduction (80% of Direct Emissions)	BACT Reduction/Design Value 2019 x 100	Annualized BACT Cost per ug/m^3 removed
Units	(ug/m^3)	(ug/m^3)	(ug/m^3)	(ug/m^3)	(%)	($)
State Office Building (SOB)	38.93	29.72	2.66	2.13	7.2%	$ 9,794,799
Fairbanks Borough Building (N	37.96	29.01	2.53	2.02	7.0%	$ 10,298,089
Hurst Road	131.63	104.81	1.55	1.24	1.2%	$ 16,809,139
North Pole Elementary (NPE)	45.3	36.48	1.35	1.08	3.0%	$ 19,299,382

Notes:
1 - Table 7.8-29 of Draft Serious SIP
2 - Table 7.8-27 of Draft Serious SIP

[10] Section 7.8.12.5 of the draft Serious SIP
[11] Table 7.8-26. "Design value contribution from major stationary source SO_2".Draft Serious SIP.
[12] Table 7.8-29. "2019 FDV for Projected Baseline and Control Scenario Calculated against a 2013 Base year".

Fairbanks exceeds the fine particulate matter standard during winter months.[13] Control technology application on major stationary sources is permanent and transcends seasons. BACT for sulfur control on major sources is an annual solution to a wintertime problem. The application of SO_2 BACT is arguably an impractical effort. Where the pollutant concentration is either achieving or almost achieving the standard, the projected impact removed by application of BACT on the major sources is about 7% of the concentration. Since the standard is attained, removing 7% more of sulfur-based $PM_{2.5}$ for costs upward of $10 million dollars per $\mu g/m^3$ seems impractical. There is a mechanism allotted within the 2016 $PM_{2.5}$ Implementation Rule for the DEC to provide a detailed written justification for eliminating, from further consideration, potential control measures for SO_2 on the community of major stationary sources based on cost ineffectiveness.

As such, UCM supports an economic infeasibility determination for the application of BACT on all major stationary sources within the nonattainment area.

Conclusion

In summary, UCM is thankful to have the opportunity to comment on the Serious Area SIP and the proposed regulations. UCM's main concerns expressed within these comments are the application of a common standard for solid fuel burning devices, the application of a workable coal-sulfur limit as BACT for the coal-fired facilities, and an economic infeasibility justification for sulfur controls for the community of major sources in the NAA. Included below are summaries highlighting key points of UCM's comments:

- BACT requirement for coal facilities to meet coal-sulfur content of 0.2% is being contested. UCMs requests a modified BACT requirement to 0.25% coal-sulfur (as received) evaluated on a six-month weighted average using UCM analyses for each shipment.
- UCM is encouraging the DEC to include provisions or circumstances within the SIP when the imposed coal-sulfur limit can be relaxed without impact to the nonattainment area. As indicated, coal resources are effectively being cut off by the imposition of a reduced limit.
- A demonstration asserting that it is technologically infeasible to install BACT for SO_2 on the FWA CHPP due to time constraints is within the DEC's authority under the provisions of the 2016 $PM_{2.5}$ Implementation Rule and should be considered.
- UCM supports an economic infeasibility determination for the community of major sources based on the cost ineffectiveness of sulfur control technology in removing 1 $\mu g/m^3$ of sulfur-based $PM_{2.5}$ from major source SO_2 contribution.
- Solid fuel burning devices are not treated equally within the Serious Area SIP. A proposition for a common emission standard for those units that do not have EPA certification or standard to meet is encouraged. Those units with EPA standards should be allowed to operate within the NAA. Also, inclusion of emission standards and criteria for coal-fired home heating devices within the regulation is encouraged

[13] Section 7.8.6 of the Draft Serious SIP

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION

18 AAC 50 AIR QUALITY CONTROL

Response to Comments on May 14, 2019, Proposed Regulations:

Chena Power Plant

November 13, 2019

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Introduction

This document provides the Alaska Department of Environmental Conservation's (ADEC) response to public comments received regarding the May 14, 2019, draft regulations pertaining to regulation changes relating to fine particulate matter (PM-2.5) including new and revised air quality controls and a new State Implementation Plan comprised of 15 sections covering monitoring, modeling, control measures, emission inventory, attainment demonstration and episode plan, which are intended to meet federal requirements for the serious nonattainment area within the Fairbanks North Star Borough (FNSB).

The details describing the proposed regulation changes were presented in ADEC's public notice dated May 14, 2019. ADEC received emailed comments, hand written comments at ADEC's open house, oral testimony at ADEC's public hearings, and comments submitted via the Air Quality Division's online comment system.

This document responds to individual comments from the Environmental Protection Agency (EPA) and aggregated comments from the public. For each section of the proposed regulations and for the State Implementation Plan (SIP), the document summarizes the comments received and provides ADEC's response.

Some of the comments contained within this document relate to the Serious SIP and responses have been incorporated by summary in the regulation response to comments.

Opportunities for Public Comment

The public notice dated May 14, 2019, provided information on the opportunities for the public to submit comments. The deadline to submit comments was July 26, 2019 at 5:00 p.m. This provided a 73 day period for the public to review the proposal and submit comments.

Opportunities to submit written comments included submitting electronic comments using the Air Quality Division's online comment form, submitting electronic comments via email, submitting written comments via facsimile, and submitting written comments via email.

Opportunities to submit oral comments included a daytime and an evening public hearing held in Fairbanks on June 26, 2019. The hearings provided the opportunity for the public to submit oral comments.

1. Aurora Energy, LLC.

1a. General Comments

Aurora Energy Comment (1):

Per the Clean Air Act (CAA), the Serious SIP was supposed to be submitted on December 31, 2017 to describe the Best Available Control Measures (BACM) bringing the area into attainment by December 31, 2019. The 2016 $PM_{2.5}$ Implementation rule allows states to request a 5-year extension of the attainment date (i.e., December 31, 2024) as part of the Serious SIP if attainment is not anticipated by December 31, 2019. Within the 5-year attainment date extension request, the state would outline Most Stringent Measures (MSM) to be applied towards bringing the area into attainment by December 31, 2024. However, if a request is not accepted by the EPA and the area does not meet attainment by the Serious Area attainment date (December 31, 2019) then the Clean Air Act is prescriptive and requires a plan to reduce the concentration of $PM_{2.5}$ by five percent annually. A plan is to be submitted one year after the attainment date (i.e., December 31, 2020) with details on how a 5% annual reduction will be achieved. What has been communicated through the Serious SIP draft is that the most expeditious attainment date for the area is 2029.

Aurora Energy Comment (2):

5% Reduction Plan

Issue: The DEC is required to submit a 5% reduction plan by December 31, 2020 which hasn't been communicated to the community and/or industry.

Request: As soon as practical, communicate the details of the plan to industry and the community.

Background:

The details of a 5% plan, or at least the outline of such a plan should be better communicated with the community. There is a lack of clarity in what measures the plan would propose. The assumption is the 5% plan will be more stringent than what is being proposed within the Serious SIP.

Response:

The 5% plan was presented as an option if the extension request is not sufficient and this requires attainment by 2024. Since, the controls currently applied in the Serious SIP will not satisfy the extension and attainment by 2024, the 5% plan is the next step. The 5% plan option was presented to the FNSB assembly and community during the public comment period, May-July 2019, and was again presented to the FNSB assembly and at a public panel discussion in North Pole on September 18th, 2019.

Aurora Energy Comment (3):

Device Requirements

Issue: DEC is adopting emission rates for solid fuel heating devices and requirements that do not give all devices equal consideration. Installation of coal-fired heating devices are not allowed unless they are a listed device (18 AAC50.079). There are no standards available in the regulations for the determination of a qualifying coal-fired heating device. Certain devices are not given options for installation within the regulation. Non-pellet fueled wood-fired hydronic heaters, although may have EPA certification under Subpart QQQQ, are not allowed to be installed within the nonattainment area per 18 AAC 50.077 (b) & (c).

Request:

Develop standards to qualify the installation of coal-fired heating units. Suggested standard should be consistent with 18 g/h emission rate for existing units or 0.10 lbs/MMBtu [heat input basis] whichever is greater.

Allow the installation of non-pellet fueled wood-fired hydronic heaters provided they are EPA certified.

Background:

The DEC is adopting several different emission rates for solid fuel heating devices which does not give all devices an equal consideration. There are EPA standards for wood stoves and hydronic heaters; also alternative standards for cordwood fired hydronic heaters.[1] These standards should be adopted without alteration. Both wood stoves and pellet fired hydronic heaters emission rates in the SIP are consistent with the 40 CFR Part 60, Subpart QQQQ standard for wood heating devices. The standards are set by the EPA and apply to manufacturers of the wood heating devices. Any such device that is approved by the EPA should be allowed in the nonattainment area, this includes outdoor hydronic heaters. Existing residential and smaller commercial coal-fired devices are required to be removed by December of 2024 and new coal-fired devices are prohibited from installation within the nonattainment area.[2] Coal-fired devices currently installed can be subject to an in-use source test to demonstrate the device meets the standard of 18 g/h of total particulate matter. This standard should also be the criteria for new residential and smaller commercial coal-fired devices. The 18 g/h standard is consistent with 0.10 lbs/MMBtu (heat input) emission rate for a unit that is rated at 400,000 Btu/hr. The Titan II auger-fed coal boilers are rated at 440,000 Btu/hr (heat output) and have undergone testing through OMNI Test Labs; the same lab that derived emission rates for the DEC which are being used in the nonattainment area SIPs. The OMNI test conducted in 2011 demonstrated that auger-fed coal fired hydronic heaters are extremely efficient.

[1] Federal Register, Vol. 80, No.50, Monday, March 16, 2015. Pg. 13672.

[2] Section 7.7.5.1.2 “Device Requirements – wood-fired and coal-fired standards”, Draft Serious SIP.

Ranking among the lowest emission rates for units tested. Emission rates of auger-fed coal-fired hydronic heaters (0.027g/MJ; 0.06 lbs/MMBtu[heat output basis]) were consistent with EPA Certified Woodstoves (0.041 g/MJ; 0.10 lbs/MMBtu [heat output basis]).[3] The DEC is aware that more efficient heating is better for the nonattainment area situation regardless of heating device. Acceptable standards for the installation of coal-fired units should be included within the proposed regulations. There should not only be a standard for the existing units referenced in the regulations but also an achievable emission rate and standards for new coal-fired units. While there are provisions for the department's approval contingency, it does not provide a target emission rate for respective devices and fuels that are not EPA certified.

<u>Aurora Energy Comment (4):</u>

Operational Requirements

Issue: The regulation isn't clear as to whether testing can be done with retrofit control devices on non- qualifying solid fuel heating devices to demonstrate qualifying emission rates. Retrofit control devices can reduce pollution emissions significantly. Use of the devices in the nonattainment area should be incentivized.

Request:

- Clarify within the regulations that emissions testing with retrofit controls can be used to qualify the emissions from solid fuel burning devices.
- The use of retrofit control devices, provided significant reductions in emissions were demonstrated, should be incentivized through an exemption for the use of the solid-fuel heating device with retrofit controls during curtailment periods.
- Suggest a lower emission standard which would qualify the use of solid fuel burning devices during curtailment periods.

Background:

The DEC is imposing curtailments for non-exempt devices during emergency episodes. Ideally, if studies associated with retrofit control devices were to demonstrate significant reductions in pollutant emissions, it would seem appropriate to establish emission rates (i.e., 0.10 lbs/MMBtu or less) and allow for the operation of certain devices that have retrofit controls without curtailment during episodes.

<u>Aurora Energy Comment (5):</u>

Small Area Sources

Issue: Coffee roasters are required to put emission controls on their processes and small area

[3] OMNI-Test Laboratories, Inc. 2011. Measurement of Space-Heating Emissions. Prepared for FNSB. Retrieved from https://cleanairfairbanks.files.wordpress.com/2012/02/omni-space-heating-study-fairbanks-draft-report-rev-4.pdf

sources are asked to submit information.

Request:

Remove the provision requiring coffee roasters to have emission controls.

Establish a significant level for small area sources similar to major source requirements. That is, require emission controls only if the sources are emitting greater than 70 tpy of the nonattainment pollutant or its precursor and are demonstrated as being significant contributors to the nonattainment area.

Background: The department is considering pollution control devices on small area sources, namely coffee roasters. The application of pollution control is requested even though there are no regulations governing coffee roasting as a source of pollution nor is there any justification indicating that coffee roasting has some significant impact on the fine particulate concentration in the area. Under the Clean Air Act and 2016 $PM_{2.5}$ implementation rule, major sources which emit greater than 70 tons per year of fine particulate matter or its precursors have the ability to show insignificance to the area problem through precursor demonstrations and can be exempt from the application of BACT. Not to mention, if a major source curtails their emissions to less than 70 tons per year, the source doesn't have to participate in any control technology assessment or application. Unless there is some reason to believe that 'coffee roasting' by individual roasters are emitting more than 70 tons of $PM_{2.5}$ through their process, then there is no justification for applying control technologies on those sources. The state is currently asking for information from other small area sources, such as charbroilers, incinerators, and waste oil burners. Industrial activities like incinerators and waste oil burners are subject to the state regulations. If the activity is an insignificant unit, or insignificant on an emission rate basis, category basis, or size and production rate basis as described in the state regulations under 18 AAC 50.326 (d) – (g) or the activity is not required to apply for a Construction Permits under 18 AAC 50.302, there should be no requirement for the small commercial activities unless it is known that they are contributing significantly to the problem. Suggested significance should be defined as the impact of the source to $PM_{2.5}$ concentration within the nonattainment area (i.e., 1.5 $\mu g/m^3$) consistent with the 2019 $PM_{2.5}$ precursor demonstration guidance.

1b. Best Available Control Technology

Aurora Energy Comment (6):

The proposed SIP considers BACT for the major sources; however, authorization of the BACT determination is not finalized through the EPA. With an impending date to install BACT four years from the date of reclassification (i.e., June 9, 2021), there doesn't seem to be time for any technological changes to the community of major sources. Although the state is trying to accommodate the deadline for BACT implementation through creative agreements (e.g., Fort Wainwright), the DEC alternatively could provide justification that the implementation of BACT is both technologically and economically infeasible at this time. This option is available to the state through 40 CFR 51.1010(3). The economically infeasible consideration is discussed later within these comments, however, a technologic infeasibility case could be considered due to the impending deadlines and the actual time it would take to design, build and implement SO_2-BACT for any facility. A cleaner approach to major source BACT would be to determine that SO_2-BACT for the community of major sources is not economically feasible. If that approach is accepted by the EPA, no further consideration would be necessary for BACT.

The ADEC has provided a BACT analysis for the Chena Power Plant (CPP) and other major sources within the nonattainment area. A top-down approach was used for the FNSB stationary sources. Aurora is providing additional information to better characterize the CPP within the context of a BACT analysis. Aurora is providing an updated emission rate, justification for technically infeasible controls for NOx, and updated capital cost for Dry Sorbent Injection (DSI). Lastly, Aurora is providing a justification for the use of a 0.25% coal-sulfur content as opposed to the 0.2% coal-sulfur content proposed by the DEC in the Serious SIP.

Response:

The Department has not taken the approach suggested by the Commenter related to conducting an economic feasibility determination for the community of stationary sources. Rather, the Department conducted BACT Determinations for each individual stationary source located in the Serious nonattainment area.

Per federal requirement, DEC evaluated all point sources with emissions greater than 70 TPY of PM-2.5 or for any individual PM-2.5 precursor (NOx, SO_2, NH_3, VOCs). These units are subject to site-specific review for BACT. A BACT limit is a numerical emission limit that is needed for each emission unit for each pollutant subject to review. The limit must be met on a continual basis; specify a control technology or work practice; include an averaging period; and be enforceable as a practical matter. BACT analyses are detailed in the BACT Determinations and the Control Strategies chapter of the SIP.

Aurora Energy Comment (7):

SO_2 and NOx emission rate

Issue: The current emission rates used by ADEC within the SIP for Aurora are not representative.

Request: Update the SIP to reflect the most current emission rates of 0.131 lbs-SO2/MMBtu and 0.359 lbs-NOx/MMBtu as demonstrated by the source test conducted in July of 2019

Background:

Aurora's current emission rates for SO_2 and NOx referenced by the ADEC for the purposes of BACT and probably the emission inventory within this draft SIP are 0.472 lbs-SO_2/MMBtu and 0.437 lbs- NOx/MMBtu. According to the DEC, these emission rates are taken from a 2011 source test; however, those emission rates are inconsistent with the emission rates associated with the 2011 source test which are 0.398 lbs-SO_2/MMBtu and 0.371 lbs-NOx/MMBtu (See Table 1). In October 2018, Aurora conducted a source test to update the SO_2 and NOx emission rates for the CPP. The emission rates derived were 0.258 lbs-SO_2/MMBtu and 0.346 lbs-NOx/MMBtu. This test was invalidated by the DEC.

Table 1: SO_2 and NOx emission rate from November 11, 2019 source testing

Pollutant	Concentration	Conversion Factor	Cd	Fd	O2 %	Emission Rate
Units	(ppm)		(lb/scf)	(scf/MMBtu)	(%)	(lbs/MMBtu)
Sulfur Dioxide	134.3	1.66E-07	7.5E-06	9739	9.5	0.398
Nitrogen Oxide	174.0	1.194E-07	2.1E-05	9739	9.5	0.371

Subsequently, a new source test was conducted with the intent of using the information within the Serious SIP for the BACT analyses, emission inventory, and modeling. Aurora has coordinated with the DEC in order to have a representative source test to better characterize the emissions from the facility. The source test was performed on July 12, 2019 and evaluated SO_2 and NOx emissions while using representative coal. The three year average coal-sulfur content was evaluated for the period July 1, 2016 through June 30, 2019 to determine the representative coal-sulfur content. The coal-sulfur content mean was 0.12%.The source test plan was approved by the department. Representatives from the department were on-site to verify the source test, the coal feed rate, and used the department's portable monitor to measure SO_2, NOx, and other constituents during the source test.

Although the results indicated within this document are preliminary, once the source test report is finalized, it will be submitted to the DEC for approval. As mentioned, the intent of the source test is to better characterize the emissions from the CPP to use in applications within the Serious SIP like the BACT analysis, emission inventory, and modeling. The new emission rate in lbs/MMBtu of the respective pollutants are 0.131 lbs-SO_2/MMBtu and 0.359 lbs-NOx/MMBtu based on EPA Method 19 and are listed in Table 2 below:

Table 2: SO_2 and NOx emission rate from July 12, 2019 source testing

Pollutant	Concentration	Conversion Factor	Cd	Fd	O2 %	Emission Rate
Units	(ppm)		(lb/scf)	(scf/MMBtu)	(%)	(lbs/MMBtu)
Sulfur Dioxide	45	1.66E-07	7.5E-06	9780	9.2	0.131
Nitrogen Oxide	172	1.194E-07	2.1E-05	9780	9.2	0.359

Provided for reference are the emission rates derived for the CPP during the October 27, 2018 source test (See Table 3). This emission rate was used in the Emission Inventory for 2018 from the facility. The test was invalidated due to a lack of representation by the DEC at the source test. The source test utilized EPA methods and an independent 3rd party source testing company to evaluate the flue gas.

Table 3: SO_2 and NOx emission rate from October 27, 2018 source testing

Pollutant	Concentration	Conversion Factor	Cd	Fd	O2 %	Emission Rate
Units	(ppm)		(lb/scf)	(scf/MMBtu)	(%)	(lbs/MMBtu)
Sulfur Dioxide	89.1	1.66E-07	1.5E-06	9776	9.2	0.258
Nitrogen Oxide	166.2	1.194E-07	2.0E-05	9776	9.2	0.346

Response:

The Department revised the baseline emission rates for NOx and SO_2 to 0.402 lb/MMBtu and 0.301 lb/MMBtu, respectively. These emission rates are the average of the two most recent approved source tests conducted on July 12, 2019 and the November 19, 2011. In calculating the average of the emission rates, the Department used 0.445 lb/MMBtu NOx and 0.471 lb/MMBtu SO_2 for the 2011 source test. These 2011 emission rates were provided to the Department both in the application for AQ0315ORL01 submitted in March of 2012 and again in the March 19, 2012 emissions fee estimate as indicated in Table 1 – Summary of Emissions Tests at the Chena Plant, November 19, 2011.

*The Commenter contends that several more recent source tests have been conducted that are more representative of actual emissions at the source. However, the October 27, 2018 source test cited by the Commenter was **not performed for any regulatory reason** as indicated in the December 26, 2018 source test report cover letter from Aurora to the Department and therefore not acceptable for calculating emissions (emphasis added).*

The Department acknowledges that the SO_2 emission rates may be lower than the 2011 tested values and the average used in the cost effectiveness calculation in the BACT Determination. The Department intends to work with Aurora to get the most representative data moving forward to ensure that the baseline emission rates are representative of actual emissions.

The Department notes that it does not plan to require implementation of SO_2 controls at the Chena Power Plant due to the financial indicators provided by Aurora and allowed under Federal Register, Vol. 81, No.164, Wednesday August 24, 2016. pg. 58085. The Department finds that the financial indicators provided by Aurora are sufficient evidence to demonstrate that imposing add-on DSI controls on the existing coal-fired boilers would cause an adverse economic impact to Aurora. For more information see Appendix III.D.7.7 for Aurora's November 1, 2018 response to DEC's information request.

The Department intends to incorporate the 0.301 SO_2 emission rate into Aurora's air quality permits to ensure the limit is federally enforceable as a practical matter. EPA has indicated its position that controls and limitations used to limit a source's Potential to Emit must be federally *enforceable. See 54 FR 27274 (June 28, 1989). Generally, to be considered federally enforceable, the permitting program must be approved by EPA into the SIP and include provisions for public participation. "In addition, permit terms and conditions must be practicably enforceable to be considered federally enforceable."*

The Department notes the NOx controls proposed in this section are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC has included with this Serious SIP, a final precursor demonstration as justification not to require NOx controls.

Aurora Energy Comment (8):

Technically Infeasible Pollution Control Option

Issue: Selective Catalytic Reduction is not technically feasible at the Chena Power Plant.

Request: Reflect that SCR is not technically feasible within the BACT analysis for the Chena Power Plant.

Background: Based on an engineering study conducted by Stanley Consultants, SCR was determined technically infeasible for reduction of NOx emissions from the industrial coal-fired boilers at the Chena Power Plant.[4] The optimal location of an SCR would be downstream of the baghouse on the common stack. This arrangement would provide for a constant operating gas temperature, reduces issues associated with fouling on the catalyst and locating the SCR downstream of the catalyst would prevent poisoning by the presence of ammonium sulfates created with the injection of ammonia in the flue gas. However, the temperatures of the flue gas after the baghouse are less than adequate. A minimum temperature of 350°F is required for the SCR catalysts to function correctly. The flue gas temperature after the baghouse is approximately 310°F.

Response:

Based on review of the engineering study conducted by Stanley Consultants, the Department revised the NOx BACT Determination to indicate that SCR is not a technically feasible control technology because of the historic flue gas temperature at the Chena Power Plant. The Department reviewed past source test data which identified flue gas temperatures within the range indicated by the Commenter (i.e., around 300°F), and as stated in the BACT Determination, SCR for NOx control has a narrow window of acceptable inlet and exhaust temperatures (500°F to 800°F). Therefore, the Department concludes that SCR is not a technically feasible control technology for the Chena Power Plant and has revised the BACT Determination and Control Strategies chapter accordingly.

The Department notes that similarly, SNCR is no longer considered a technically feasible

[4] Stanley Consultants, Inc. (2019, April). "Best Available Control Technology Analysis – Independent Assessment of Technical Feasibility and Capital Cost". Aurora Energy, LLC.

control technology because it requires a reaction temperature window of 1,600ºF to 2,200ºF. The Department further notes that the NOx controls proposed in this section are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC has included with this Serious SIP, a final precursor demonstration as justification not to require NOx controls.

Aurora Energy Comment (9):

Updated Capital Cost for DSI

Issue: Capital cost for DSI as provided to the DEC was determined to be $20,682,000.

Request: Use the capital cost of $20,604,000 for DSI in the BACT analysis to determine a cost effectiveness value.

Background: A refined and final opinion of probable cost is being provided for the CPP DSI which is $20,604,000.[5]

Response:

The Department recalculated total project cost for DSI on Aurora's coal-fired boilers using the refined and final opinion of probable cost of $20,604,000. The Department notes that this change has a negligible impact on cost per ton of SO_2 removed, now calculated at $9,686/ton using the average of emission rates discussed in Response to Comment 7.

Aurora Energy Comment (10):

BACT Cost Effectiveness Calculations

Issue: The DEC BACT cost effectiveness values in the draft SIP for the Chena Power Plant are not representative.

Request: Change the section to reflect representative cost effectiveness values based on the representative emission rates outlined below.

Background:

BACT cost effectiveness calculations were done by the DEC using established cost estimating procedures. The procedures require that inputs are adjusted to reflect the conditions of the facility assessed. Some of the key inputs identified by the DEC are as follows: the emission rate for SO_2 and NOx were 0.472 lbs-SO_2/MMBtu and 0.437 lbs-NOx/MMBtu, a retrofit factor of 1.5 was used for a difficult retrofit, an interest rate of 5.5%, and equipment life for NOx and SO_2 controls were 20 and 15 years respectively. Using the DEC inputs for wet scrubbers and SDA

[5] Ibid.

technologies, the cost effectiveness value and capital costs output are not consistent with the text within the draft SIP. DEC calculated the cost effectiveness for the installation of wet scrubbers and SDA to be $10,620/ton and $11,298/ton. When the DEC inputs were used within the spreadsheets, the cost effectiveness values for the installation of wet scrubbers and SDA were $14,572/ton and $15,726/ton (See Table 4 - values in parentheses) respectively. However, when the emission rate was updated in the spreadsheets to the representative emission rate from the July 12, 2019 source test (0.131 lbs-SO_2/MMBtu), the cost effectiveness value increased to $49,585/ton for wet scrubbers and $53,909/ton for SDA. Using the DEC's spreadsheets for DSI cost effectiveness, Aurora adjusted the capital cost of DSI from $20,682,000 to $20,604,000 based on refined opinion of probable cost and used the updated emission rates referenced in Table 2. The cost effectiveness value for DSI increased from $7,495/ton to $18,007/ton (Table 4).

Table 4: Updated Cost Effectiveness Value based on SO_2 and NOx Representative Source Test (7/12/19)

Technology	DEC Cost Effectiveness Value (cost/ton removed)	Capital Cost ($)	Updated Cost Effectiveness Value (cost/ton removed)	Adjusted Capital Cost ($)
Selective Catalytic Reduction	$4,023/ton		Not Technically Feasible	
Selective Non-Catalytic Reduction	$2,227/ton		$2,587/ton	
Wet Scrubbers	$10,620/ton ($14,572/ton)	$57,019,437 ($87,152,852)	$49,585/ton	$82,323,012
Spray Dry Absorbers	$11,298/ton ($15,726/ton)	$51,019,437 ($81,280,628)	$53,909/ton	$77,293,649
Dry Sorbent Injection	$7,495/ton	$20,682,000	$18,007/ton	$20,604,000

Note: Values in parentheses are the output from the cost development methodology used by the DEC with inputs suggested within Section 7.7.8 "Control Strategies" of the draft Serious SIP.

Based on the adjusted values, it is not cost effective to install BACT for SO_2 at the Chena Power Plant.

<u>Response:</u>

The Department revised the baseline emission rates for NOx and SO_2 to 0.402 lb/MMBtu and 0.301 lb/MMBtu, respectively. These emission rates are the average of the two most recent approved source tests conducted on July 12, 2019 and the November 19, 2011. In calculating the average of the emission rates, the Department used 0.445 lb/MMBtu NOx and 0.471 lb/MMBtu SO_2 for the 2011 source test. These 2011 emission rates were provided to the Department both in the application for AQ0315ORL01 submitted in March of 2012 and again in the March 19, 2012 emissions fee estimate as indicated in Table 1 – Summary of Emissions Tests at the Chena Plant, November 19, 2011.

The Commenter contends that several more recent source tests have been conducted that are more representative of actual emissions at the source. However, the October 27, 2018 source *test cited by the Commenter was* ***not performed for any regulatory reason*** *as indicated in the December 26, 2018 source test report cover letter from Aurora to the Department and therefore not acceptable for calculating emissions (emphasis added).*

The Department acknowledges that the SO_2 emission rates at the Chena Power Plant may be lower than the 2011 tested values and the average used in the cost effectiveness calculation in the BACT Determination. The Department intends to work with Aurora to get the most representative data moving forward to ensure that the baseline emission rates are representative of actual emissions.

The Department notes that it does not plan to require implementation of SO_2 controls at the Chena Power Plant due to the financial indicators provided by Aurora and allowed under Federal Register, Vol. 81, No.164, Wednesday August 24, 2016. pg. 58085. The Department finds that the financial indicators provided by Aurora are sufficient evidence to demonstrate that imposing add-on DSI controls on the existing coal-fired boilers would cause an adverse economic impact to Aurora. For more information see Appendix III.D.7.7 for Aurora's November 1, 2018 response to DEC's information request.

The Department intends to incorporate the 0.301 SO_2 emission rate into Aurora's air quality permits to ensure the limit is federally enforceable as a practical matter. EPA has indicated its position that controls and limitations used to limit a source's Potential to Emit must be federally enforceable. See 54 FR 27274 (June 28, 1989). Generally, to be considered federally enforceable, the permitting program must be approved by EPA into the SIP and include provisions for public participation. "In addition, permit terms and conditions must be practicably enforceable to be considered federally enforceable."

The Department notes the NOx controls proposed in this section are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC has included with this Serious SIP, a final precursor demonstration as justification not to require NOx controls.

Aurora Energy Comment (11):

Sulfur Content of Coal

Issue: Proposed BACT for coal-sulfur content of 0.2% will cut off access to tens of millions of tons of coal for UCM as well as pose a potential threat of fuel supply interruption for the coal fired power plants.

Request: Adopt a new standard of 0.25% based on semi-annual weighted averages of coal-sulfur content in shipments of coal within semi-annual periods corresponding to Facility Operating Report reporting periods.

Background:

The ADEC has proposed that Best Available Control Technology (BACT) for coal burning facilities in the nonattainment area is a coal-sulfur limit of 0.2% sulfur by weight. Usibelli Coal Mine (UCM) is the only source of commercial coal available to the coal-fired facilities within the Fairbanks North Star Borough fine particulate nonattainment area. The mine has limited ability to affect the sulfur content in the coal. There isn't a coal washing or segregating facility associated with UCM which could ensure a consistent coal-sulfur concentration. Current practice for providing low-sulfur coal to customers is identifying sulfur content of the resource through drilling and sampling efforts. However, no matter how much sampling is done, the ability to characterize the sulfur content of the coal actually mined is limited.

Within the millions of tons of coal resources available to UCM, there is a significant amount of coal with higher sulfur content than 0.2%; in fact, any limit proposed to the coal sulfur content is effectively cutting off access to tens of millions of tons of coal resources. As such, AE proposes that the coal-sulfur limit be lowered to 0.25% on an as received basis (wet) as opposed to 0.2% as proposed by ADEC. The increase in coal-sulfur content will help with coal accessibility and availability over the next decade and still provides ADEC with a 37.5% reduction in the potential to emit based from the current limit of 0.4%.

The state was silent on how the measure was to be reported or considered within a regulatory context. The ADEC's standard permit condition for coal fired boilers (Standard Condition XIII) requires that the permittee report sulfur content of each shipment of fuel with the semi-annual Facility Operating Reports. UCM currently provides semi-annual reports to all customers which includes sulfur content of each shipment of coal along with the weighted average coal-sulfur content for the six-month period coinciding with the operating reports' reporting period. UCM and Aurora propose that the standard operating permit condition remain the same and that facilities continue to provide the state with the sulfur content of each shipment of fuel; in addition, the weighted average coal-sulfur content of the shipments received by the facility during the reporting period would be referenced in the operating report.

<u>Response:</u>

The Department acknowledges that the 0.2 percent sulfur content limit wasn't included as part of the BACT determination and therefore didn't go through EPA's top-down evaluation process. Instead it was established in the Control Strategies chapter as a method to limit SO_2 emissions in a reasonable way. The Department received multiple comments requesting that this limit be revised to 0.25 percent sulfur by weight. A 0.25 percent sulfur limit meets the Department's need to ensure no backsliding occurs and therefore acquiesced to that request.

The Department is therefore requiring all coal delivered to stationary sources in the Fairbanks nonattainment area to have a gross as received sulfur content of no greater than a 0.25% by weight. This new coal sulfur requirement will need to be incorporated into Aurora's air quality permit.

Requiring the change in sulfur content to be implemented on an as-delivered-basis will allow the coal already stockpiled at the Chena Power Plant to be utilized and ensure a continuous supply of coal is available.

1c. SO_2 Precursor Analysis

Aurora Energy Comment (12):

Issue: There are inconsistencies in DEC's information with respect to SO_2. The major source contribution to sulfur-based PM2.5 from major source SO_2 ground level concentrations have increased from 2008; even though point source SO_2 emissions have decreased while SO_2 emissions from heating oil and total SO_2 emissions have increased.

Requests:

- Change referenced PM2.5 significance threshold from 1.3 µg/m^3 to 1.5 µg/m^3 based on the final EPA PM2.5 Precursor Demonstration Guidelines (2019).
- Revisit SO2 Analysis after applying representative emission rates for the Chena Power Plant for SO_2 and NOx (0.131 lbs-SO2/MMBtu and 0.359 lbs-NOx/MMBtu).
- Clarify discrepancy between the 2008 CALPUFF model output reflecting 22% contribution to ground-level SO2 from major sources and current CMAQ evaluation reflecting 39% SO 2 contribution from major sources.
- Reconsider SO_2 Precursor Demonstration for Major Source impact using a sensitivity analysis to determine significance.

Background:

The DEC completed an SO2 Analysis using the 2019 projected baseline inventory and run through CMAQ model. All of the SO2 emissions were removed from the point source sector in a knock out model run. The meteorology used was from 2008, which is consistent for all of the model runs. The SO2 from major stationary sources were found to contribute significantly to the PM2.5 concentrations at the State Office Building (SOB) [1.79 µg/m^3] and at the monitoring site adjacent to the Borough building (NCORE) [1.70 µg/m^3] in Fairbanks. The impact of SO2 from major sources was also determined to be significant at all four monitoring sites (SOB, NCORE, Hurst Road, and NPE) when an alternative approach to estimating the design value contribution from major stationary sources was applied [respectively: 2.66 µg/m^3,2.53 µg/m^3, 1.55 µg/m^3, 1.35 µg/m^3]. The DEC referenced an insignificance threshold of 1.3 µg/m^3 to determine significance; however, final PM2.5 Precursor Demonstration Guidance has changed that threshold to 1.5 µg/m^3.[6]

Regardless of the change in significance value, three of the sites (SOB, NCOR, and Hurst Road) would still be considered significant when the alternative approach to estimating the design value contribution is considered. If the impact of major source SO_2 emissions on PM2.5 exceeds 1.5 µg/m^3, then a sensitivity- based analysis may be conducted to show that a reduction of SO_2 emissions in the range of 30 - 70% would only have an insignificant impact on lowering $PM_{2.5}$ concentration. Aurora demonstrated that there was justification to pursue a precursor

[6] https://www.epa.gov/sites/production/files/2019-05/documents/transmittal_memo_and_pm25_precursor_demo_guidance_5_30_19.pdf

demonstration using information provided in the moderate area SIP. The major source contribution to $PM_{2.5}$ from SO_2 was determined to be 1.98 $\mu g/m^3$ of water-bound ammonium sulfate. The conclusion of the exercise was that a 70% reduction in SO_2 would demonstrate insignificance of the SO_2 contribution from major sources on $PM_{2.5}$ concentration [i.e., 1.45 $\mu g/m^3$].[7] It is Aurora's opinion that a successful precursor demonstration may still be possible using a 50% reduction even considering DEC's alternative approach to estimating design value contributions from major source SO_2. However, the DEC has indicated due to sulfate model performance uncertainty and significance of the major source contribution from SO_2 emissions, there is not enough justification to pursue the demonstration.

Aurora has a few concerns with the SO_2 analysis. Probably the most significant is that the contribution of SO_2 at the SOB monitor from major sources increased to 39% from 22% as described in the Moderate Area SIP (2014). CALPUFF modeling showed that the point source SO_2 contribution to the SOB monitoring site was 22% for an episode in 2008. The emission inventory for 2008, 2013, and the projected 2019 show a decreasing trend in SO_2 emissions for point sources (See Table 5). The ratio between SO_2 emissions from oil heating and point sources (Oil Heating SO_2/Point Source SO_2) increases from 2008 to 2019 (projected) from 0.46 to 0.51 for the planning inventory in the NAA (Table 5). This would suggest that the amount of SO_2 emissions from oil increased in relation to the amount of SO_2 emissions from point sources. That fact is counterintuitive to the modeling outputs which indicates SO_2 contribution from point sources increased 18% from 2008 to 2019 at the SOB.

The total SO_2 emissions per day in 2019 is about two times what it was in 2008 and 2013 (See Table 5). The difference is attributed to an increase in Non-Road Mobile sources; in fact, a change in jet fuel between 2013 and 2019 is referenced as the cause of the increase.[8] It would seem that the likelihood for an increased impact at the monitors from SO_2 should have come from this change as opposed to the point sources.

Table 5: Baseline Episode Average Daily SO_2 Emissions (tons/day) by Source Sector

Source Sector	Modeling Inventory Grid 3 Domain			Planning Inventory NA Area		
	2008	2013	2019 (projected)	2008	2013	2019 (projected)
Point Sources	8.380	7.40	7.32	8.167	7.22	7.13
Area, Space Heating, Oil	4.121	3.68	3.90	3.719	3.42	3.61
Total	12.875	12.65	25.58	12.155	11.92	22.36

Note: 2008 data from Moderate Area SIP (Table 5.6-7); 2013 & 2019 data from draft SIP, Tables 7.6-10 & 7.6-12, respectively.

The increase in point source contribution of SO2 at the monitoring sites is, therefore, perplexing. Aurora also believes that point source emission of SO_2 in the inventories may be inflated due to the emission factor used to determine Aurora's SO_2 emissions (and NOx emissions). Within the BACT section of the draft SIP, an emission factor for SO_2 was referenced as being 0.472 lbs-SO_2/MMBtu. A recent source test conducted on July 12, 2019 at

[7] Memo. Ramboll. "Summary of issues related to SO_2 precursor demonstration for Fairbanks". 2018.
[8] Section 7.6.3.2 "2019 Projected Baseline Emission Inventory", Draft Serious SIP

the Chena Power Plant was arranged specifically to better characterize the emission rates for SO_2 and NOx from the plant. The test plan was approved by the state with additional scrutiny due to its intended use. The test demonstrated an emission factor of 0.131 lbs-SO_2/MMBtu. This value is a preliminary emission rate. The final report will be provided to the DEC so that, when approved, the new emission rate would be updated in the state's databases and worksheets for the final submittal of the Serious Area SIP to the EPA.

Aurora would also like the state to clarify the discrepancy between the 2008 CALPUFF modeling, which showed a major source SO_2 contribution of 22% at the SOB monitoring site, in relation to the recent evaluation referenced under the SO_2 Analysis (Section 7.8.12.5) where major source SO_2 contribution to the SOB was 39%. Aurora would like the DEC to reconsider an SO_2 precursor demonstration for major source contribution to $PM_{2.5}$ concentration. Aurora believes a successful demonstration could be done using the provisions of a sensitivity analysis as described in the 2019 $PM_{2.5}$ Precursor Demonstration Guidance.

Response:

The significance threshold has been updated to reflect 1.5 ug/m^3, which is in the precursor guidance. The discrepancies are due to the 2008 emissions inventory for Calpuff was an early version and used to estimate SO_2 into the non-attainment area. The CMAQ emission inventory was updated to reflect source specific day and hour emissions provided by the point sources. The SO_2 analysis was performed as a knock out run as outlined in the precursor guidance. DEC will not be reconsidering the SO_2 analysis for the Serious Area SIP. The EPA will not approve an SO_2 precursor regardless of the contribution because of outstanding science questions related to sulfate. Please see EPA comments on the SO_2 analysis:

EPA Comment (4):

"**SO_2 Precursor Analysis.** We understand that there is interest in a precursor demonstration for SO_2, but that there are information limitations that restrict the ability to make such a demonstration. On page 43 of the modeling chapter, Vol. II:III.D.7.8, it is stated that no sensitivity-based precursor demonstration was pursued for SO_2 as a result of limitations on scientific information to support such a demonstration and therefore precursor emissions are considered significant. We agree with the State's conclusion that SO_2 precursor emissions are considered significant for the reasons provided by the State. Until the informational and technological limitations are addressed, SO_2 must be assessed for BACM and BACT for all source categories. See 40 CPR 51.1010(a). We summarize some of the informational and technological limitations here.

Model development for SO_2 and sulfate formation is an active area of research and we are hopeful to have improved modeling tools in the coming years. Beginning on page 47 of the modeling chapter and continuing on page 58, an SO_2 analysis is presented that attempts to quantify the point source contribution to total observed sulfate. EPA is concerned that, while the SO_2 analysis presented is not intended as a proposed precursor demonstration, the analysis makes several unsupported assumptions that we view as serious flaws in the methodology. First, it is assumed without supporting information that sulfur oxidation occurs uniformly throughout the airshed and on all sources of SO_2 at equal rates. Second, it is assumed that currently modeled sulfate impacting the monitors is an unbiased and accurate quantification of primary sulfate impacts at the monitors, essentially assuming the modeling is perfect in regard to primary sulfate impacts but does not provide a model performance evaluation that supports this assumption.

Given the technical limitations of current modeling tools to correctly model secondary sulfate in winter environments such as Fairbanks and the flaws in the presented SO_2 analysis, we agree that it does not make sense to pursue a sensitivity-based precursor demonstration at this time. (Improve)"

1d. Major Source Economic Infeasibility Justification

Issue: The DEC has the option to demonstrate the economic infeasibility of SO_2 BACT for major sources within the nonattainment area under 40 CFR 51.1010 (3) based on cost effectiveness. The most cost effective value for operating BACT controls on the community of major sources to remove 1 $\mu g/m^3$ of PM2.5 is $9,794,799 per year [See Table 7b].

Request:

- Define cost effectiveness as cost per 1 $\mu g/m^3$ of PM2.5 for this exercise.
- Derive a cost per ton removed for each major source in the nonattainment area by adjusting operational load to represent actual SO2 emissions in the spreadsheets for each facility provided within the appendices of the "Control Strategies" section of the draft serious SIP.
- Evaluate the cumulative annualized cost incurred by the community of major sources within the nonattainment area based on potential tons removed from implementing SO2 BACT using actual emissions (instead of PTE).
- Correlate annualized cost of SO2 BACT controls with results from the SO2 Analysis section of the draft SIP (Section 7.8.12.5) to derive a cost per $\mu g/m^3$ mitigated from applying SO2 control technologies.

Background:

Major stationary sources are a subgroup of emission sources that are given special consideration under nonattainment area provisions. Point sources with emissions greater than 70 tons per year of PM2.5 or any individual precursor (NOx, SO2, NH3, VOCs) are evaluated for appropriate control. NOx and SO2 were addressed on an emission unit specific basis in DEC's Best Available Control Technologies (BACT) determinations. The DEC's evaluation considered technical feasibility and estimates of emissions reductions to meet a defined emission limit.

Operations at the facility's potentials to emit is used for the purpose of identifying a cost effectiveness for each technology in cost per ton removed.

The BACT analyses evaluate pollution control independent of the nonattainment area problem; it is simply triggered as a condition of an area defined as being in serious nonattainment of a pollutant standard. As described in the 2016 PM2.5 Implementation Rule, the state can provide either a technologic or an economic infeasibility demonstration for control measures.[9] The argument must illustrate it is not technologically or economically feasible to implement the control measure by the end of the tenth calendar year (i.e., December 31, 2019 for the FNSB NAA) following the effective date of the designation of the area. Aurora believes that there is enough evidence to substantiate that SO2 controls on the community of major sources is economically infeasible.

Economic Infeasibility Justification

The DEC has determined BACT is comprised of sulfur controls for major stationary sources. The DEC has also determined that sulfur controls are economically infeasible for one major source, silent on infeasibility for another, and partially economically infeasible for a couple of major sources within the NAA.[10] Per regulation, DEC has the authority to demonstrate that any measure identified is economically infeasible.[11] It is within the DEC's authority to determine that BACT for sulfur control is economically infeasible for the community of major sources in the NAA based on cost effectiveness.[12] If cost effectiveness is defined as cost per $\mu g/m^3$ removed, there is a clear justification to eliminate sulfur control measures from the community of major sources. The most cost effective value for operating BACT controls on the community of major sources to remove 1 $\mu g/m^3$ of PM2.5 is $9,794,799 per year [See Table 7b].

Annualized Cost of BACT Implementation

The DEC derived cost effectiveness value in cost per ton removed is established through the implementation of the BACT analysis. The DEC preferred BACT controls and cost effectiveness value are referenced in Section 7.7.8 of the SIP.[13] Dry Sorbent Injection (DSI) is selected for the coal fired boilers with an 80% reduction in SO_2 and ULSD is suggested for GVEA's North Pole Plant and Zehnder Facility with a 99.7% removal rate for SO_2. Based on the Potential to Emit (PTE) of each facility, the state derives a cost effectiveness value for the sources.

Annualized cost to implement BACT for the community of major sources are based on operating scenarios for both PTE and actual emissions (2013)[14] from the facilities. The results are illustrated in Table 6a and 6b. The cost effectiveness value (cost/ton removed) is multiplied by the amount of pollution removed (tons) to derive an annual cost for BACT for each facility. The total annualized cost is the sum of the cumulative annual operating cost for the controls on

[9] 40 CFR 51.1010 (3)
[10] Section 7.7.8 of the draft Serious SIP
[11] 40 CFR 51.1010 (3)
[12] 12 40 CFR 51.1010 (3)(ii)
[13] Appendix III.D.7.07 Control Strategies: https://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip/
[14] Table 7.6-9 "2013 SO2 Episodic vs. Annual Average Point Source Emission (tons/day)"[Draft Serious SIP]ADEC

all the major sources in the NAA. The annualized costs do not include the cost of fuel switching for smaller diesel engines, backup generators and boilers that are found on the campuses of certain facilities (e.g., UAF, FWA). The total annualized BACT implementation cost to operate at the PTEs is $49,296,062; annualized cost considering actual emissions is $20,843,332 (See Tables below).

Table 6a: BACT Annualized Costs Based on Potential To Emit

Facility	BACT (SO_2 Control)	SO_2 Reduction	SO_2 Emissions PTE[3]	SO_2 Reduction[3]	Cost/ton removed [2,3]	Annualized Cost
Units		(%)	(tpy)	(tpy)	($)	($)
Chena Power Plant	DSI	80	1,004.0	803.0	$ 7,495	$ 6,018,485
FWA	DSI	80	1,168.5	934.8	$ 10,329	$ 9,655,331
NPP-EU1	ULSD	99.7	1,486.4	1,482.0	$ 9,139	$ 13,543,998
NPP-EU2	ULSD	99.7	1,356.1	1,352.0	$ 9,233	$ 12,483,016
UAF	DSI	80	242.5	194.0	$ 11,578	$ 2,246,132
Zender	ULSD	99.7	598.6	597.0	$ 8,960	$ 5,349,120
Notes: See Below.					Total Annualized Cost	$ 49,296,082

Table 6b: BACT Annualized Costs Based on Actual Emissions

Facility	BACT (SO_2 Control)	SO_2 Reduction	SO_2 Emissions (Actual)[1,3]	SO_2 Reduction	Cost/ton removed[4]	Annualized Cost
Units		(%)	(tpy)	(tpy)	($)	($)
Chena Power Plant	DSI	80	711.8	569.4	$ 8,960	$ 5,101,824
FWA	DSI	80	766.5	613.2	$ 11,235	$ 6,889,302
NPP-EU1	ULSD	99.7	142.3	141.9	$ 12,169	$ 1,726,454
NPP-EU2	ULSD	99.7	422.3	421.0	$ 9,453	$ 3,980,026
UAF	DSI	80	219.0	175.2	$ 11,578	$ 2,028,466
Zender	ULSD	99.7	73.0	72.8	$ 15,351	$ 1,117,261
Notes:					Total Annualized Cost	$ 20,843,332

1 - Table 7.6-9 "2013 SO2 Episodic vs. Annual Average Point Source Emissions (tons/day)"
2 - Sectoin 7.7.8 of SIP
3 - BACT Spreadsheets (May 2019) in SIP for Listed Facilities; adjusted AE emission factor of 0.472 lbs-SO2/MMBtu referenced in BACT Section of SIP.
4 - Cost/ton removed after adjusting operational load in BACT Spreadsheets (May 2019) to reflect actual emissions; AE emission factor of 0.472 lbs-SO_2/MMBtu

Major Source SO_2 Control Cost Effectiveness: Cost per $\mu g/m^3$ $PM_{2.5}$ Removed

The DEC provided an SO2 analysis using the 2019 projected baseline inventory.[15] The DEC determined that major stationary sources were found to contribute significantly to $PM_{2.5}$ concentrations at the State Office Building (SOB) and the monitor adjacent to the Borough building (NCORE) in downtown Fairbanks. The impact at the monitors were 1.79 $\mu g/m^3$ and 1.70 $\mu g/m^3$ respectively.[16] The impact at the Hurst Road and North Pole Elementary (NPE) monitors were 0.04 $\mu g/m^3$ and 0.10 $\mu g/m^3$ respectively.

Assuming that an 80% removal of the point source emissions of SO2 would translate to an 80% reduction to the impact from major sources of sulfur-based PM2.5 at the monitors, the amount of PM2.5 reduced at the SOB, NCORE, Hurst Road, and NPE monitors would be 1.43 $\mu g/m^3$, 1.36 $\mu g/m^3$, 0.03 $\mu g/m^3$, and 0.08 $\mu g/m^3$ respectively. Based on the total annualized cost for BACT controls using actual emissions ($20,843,332) the cost effectiveness value in cost per $\mu g/m^3$ of $PM_{2.5}$ removed is at the best, $14,555,400 per $\mu g/m^3$ removed and at the worst $651,354,137 per $\mu g/m^3$ removed (Table 7a). If the alternative approach to the SO_2 design value contribution from major sources is considered then the cost effectiveness at best is $9,794,799 per $\mu g/m^3$ and at worst is $19,299,382 per $\mu g/m^3$ (Table 7b).

Ironically, the cost per $\mu g/m^3$ removed is less at the SOB and NCORE sites where the projected

[15] Section 7.8.12.5 of the draft Serious SIP
[16] Table 7.8-26. "Design value contribution from major stationary source SO2".Draft Serious SIP.

design value is in compliance with the standard. The projected design value provided by the DEC for 2019 meet attainment at the SOB and NCORE sites which are of 29.72 µg/m^3 and 29.01 µg/m^3 respectively[17]; the attainment standard is 35 µg/m^3. The 2019 design values at the Hurst Road and NPE monitors were 104.81 µg/m^3 and 36.48 µg/m^3, both clearly above the attainment standard of 35 µg/m^3. The impact from the major sources is less significant at the sites where the 2019 projected design value violates the standard.

Table 7a: Cost Effectiveness Based on Design Value Contribution SO_2 from Major Stationary Sources

Site	Design Value Base Year 2013[1]	Projeced Design Value Year 2019[1]	Major Source Sulfur-Based Particulate Contribution[2]	BACT Reduction (80% of Direct Emissions)	BACT Reduction / Design Value 2019	Annualized BACT Cost per ug/m^3 removed
Units	(ug/m^3)	(ug/m^3)	(ug/m^3)	(ug/m^3)	(%)	($)
State Office Building (SOB)	38.93	29.72	1.79	1.43	4.8%	$ 14,555,400
Fairbanks Borough Building	37.96	29.01	1.70	1.36	4.7%	$ 15,325,980
Hurst Road	131.63	104.81	0.04	0.03	0.0%	$ 651,354,137
North Pole Elementary (NPE)	45.3	36.48	0.10	0.08	0.2%	$ 260,541,655

Notes:
1 - Table 7.8-29 of Draft Serious SIP
2 - Table 7.8-26 of Draft Serious SIP

Table 7b: Cost Effectiveness Based on Alternative Approach to Design Value Contribution SO_2 from Major Stationary Sources

Site	Design Value Base Year 2013[1]	Projeced Design Value Year 2019[1]	Major Source Sulfur-Based Particulate Contribution[2]	BACT Reduction (80% of Direct Emissions)	BACT Reduction/Design Value 2019 x 100	Annualized BACT Cost per ug/m^3 removed
Units	(ug/m^3)	(ug/m^3)	(ug/m^3)	(ug/m^3)	(%)	($)
State Office Building (SOB)	38.93	29.72	2.66	2.13	7.2%	$ 9,794,799
Fairbanks Borough Building	37.96	29.01	2.53	2.02	7.0%	$ 10,298,089
Hurst Road	131.63	104.81	1.55	1.24	1.2%	$ 16,809,139
North Pole Elementary (NPE)	45.3	36.48	1.35	1.08	3.0%	$ 19,299,382

Notes:
1 - Table 7.8-29 of Draft Serious SIP
2 - Table 7.8-27 of Draft Serious SIP

Fairbanks exceeds the fine particulate matter standard during winter months.[18] Control technology application on major stationary sources is permanent and transcends seasons. BACT for sulfur control on major sources is an annual solution to a wintertime problem. The application of SO_2 BACT is arguably an impractical effort. Where the pollutant concentration is either achieving or almost achieving the standard, the projected impact removed by application of BACT on the major sources is about 7% of the concentration. Since the standard is attained, removing 7% more of sulfur-based $PM_{2.5}$ for costs upward of $10 million dollars per µg/m^3 seems impractical. There is a mechanism allotted within the 2016 $PM_{2.5}$ Implementation Rule for the DEC to provide a detailed written justification for eliminating, from further consideration, potential control measures for SO_2 on the community of major stationary sources based on cost ineffectiveness.

As such, Aurora supports an economic infeasibility determination for the application of BACT on all major stationary sources within the nonattainment area.

<u>Response:</u>

The Department has not taken the approach suggested by the Commenter related to conducting an economic feasibility determination for the community of stationary sources. Rather, the

[17] Table 7.8-29. "2019 FDV for Projected Baseline and Control Scenario Calculated against a 2013 Base year".
[18] Section 7.8.6 of the Draft Serious SIP

Department conducted BACT Determinations for each individual stationary source located in the Serious nonattainment area.

Per federal requirement, DEC evaluated all point sources with emissions greater than 70 TPY of PM-2.5 or for any individual PM-2.5 precursor (NOx, SO_2, NH_3, VOCs). These units are subject to site-specific review for BACT. A BACT limit is a numerical emission limit that is needed for each emission unit for each pollutant subject to review. The limit must be met on a continual basis; specify a control technology or work practice; include an averaging period; and be enforceable as a practical matter. BACT analyses are detailed in the BACT Determinations and the Control Strategies chapter of the SIP.

The Department notes that Dry Sorbent Injection was cost effective for a BACT control in a serious non-attainment area, but Aurora provided financial indicators that demonstrated that it would have an adverse effect for business purposes. As indicated in the Control Strategies chapter, DEC finds that it is economically infeasible for Aurora Energy to implement retrofit SO_2 controls on its emission units at the Chena Power Plant.

1e. $PM_{2.5}$ Emission Reduction Credits

Issue: Currently there are no provisions for the FNSB NAA within the regulations that establish emission reduction credits.

Request: Include provisions in the Serious SIP for establishing PM2.5 emission reduction credits per 40 CFR 51 Appendix S.

Background:

Aurora Energy requests that the SIP include provisions for establishing PM2.5 emission reduction credits, as provided in 40 CFR 51 Appendix S. The SIP should recognize that the most fertile area for establishing further emission reduction credits involves reducing emissions from wood-fired residential heaters – stoves and fireplaces. The approach to accounting for dried wood emissions should consider enhanced wood-moisture reduction through a process such as kiln drying, to levels as low as 15 percent (dry wood basis) beyond the 20 percent levels in the proposed SIP and allow those lower emissions to be applied as emission reduction credits for potential future development within the Non-Attainment Area. The approach also lessens the level of involvement of agency oversight of the individual components of the SIP that are related to residential wood combustion. Residential wood combustion is an ingrained cultural component of life in Fairbanks, and the proposed enhanced drying option is likely to be well supported by members of the community. We urge consideration of this approach that will both clean the air and provide some potential for emissions increases, through offsets developed under this proposal, to further strengthen the economic viability of the Fairbanks North Star Borough community.

1f. Conclusion

In summary, there are several elements to the SIP that Aurora is addressing as a part of the public comment. The DEC has an incredible task which is being addressed to the extent possible with the time and resources available. Below are summaries of the key points Aurora addressed within the comments:

- BACT requirement for coal facilities to meet coal-sulfur content of 0.2% is being contested. Auroras requests a modified BACT requirement to 0.25% coal-sulfur (as received) evaluated on a six-month weighted average using UCM analyses for each shipment.
- SO_2 and NOx emission rates being used for Aurora within the SIP are not accurate representation of the facilities emission rates. Suggest using newly established rates derived through representative source testing with representative coal.
- Additional information is provided to support technologic infeasibility of SCR, a change in the capital cost for DSI, and emission rate changes for the determination of cost effectiveness within the context of the BACT analyses.
- Aurora supports an economic infeasibility determination for the community of major sources based on the cost ineffectiveness of sulfur control technology in removing 1 $\mu g/m^3$ of sulfur-based $PM_{2.5}$ from major source SO_2 contribution.
- Aurora requests that the SIP include provisions for establishing $PM_{2.5}$ emission reduction credits, as provided in 40 CFR 51 Appendix S.
- One of the key parts to the future of the nonattainment area is the 5% reduction plan. The elements within this plan, which is anticipated for submittal at the end of 2020, have not been communicated to the community or industry. It is the opinion of Aurora that communication with the community about the elements within the 5% reduction plan is warranted and necessary.
- Solid fuel burning devices are not treated equally within the Serious Area SIP. A proposition for a common emission standard for those units that do not have EPA certification or standard to meet is encouraged. Those units with EPA standards should be allowed to operate within the NAA. Also, inclusion of emission standards and criteria for coal-fired home heating devices within the regulation is encouraged.
- Retrofit control devices should be encouraged for use to meet emission standards as necessary.
- The departments' imposition of control technologies on small sources, such as coffee roasters, is not supported. Major sources are able to take operational limits to reduce emissions to less than 70 tons per year to avoid pollution control. Small commercial sources shouldn't be subject to pollution controls unless there is evidence that their emissions are significant.

Enclosure:

Stanley Consultants, Inc. (2019, April). "Best Available Control Technology Analysis – Independent Assessment of Technical Feasibility and Capital Cost". Aurora Energy, LLC.

2. Comments from Usibelli Coal Mine, Inc..

2a. Device Requirements

Issue: DEC is adopting emission rates for solid fuel heating devices and requirements that do not give all devices equal consideration. Installation of coal-fired heating devices are not allowed unless they are a listed device (18 AAC50.079). There are no standards available in the regulations for the determination of a qualifying coal-fired heating device. Certain devices are not given options for installation within the regulation. Non-pellet fueled wood-fired hydronic heaters, although may have EPA certification under Subpart QQQQ, are not allowed to be installed within the nonattainment area per 18 AAC 50.077 (b) & (c).

Request:

- Develop standards to qualify the installation of coal-fired heating units. Suggested standard should be consistent with 18 g/h emission rate for existing units or 0.10 lbs/MMBtu [heat input basis] whichever is greater.
- Allow the installation of non-pellet fueled wood-fired hydronic heaters provided they are EPA certified.

Background:

The DEC is adopting several different emission rates for solid fuel heating devices which does not give all devices an equal consideration. There are EPA standards for wood stoves and hydronic heaters; also alternative standards for cordwood fired hydronic heaters.[19] These standards should be adopted without alteration. Both wood stoves and pellet fired hydronic heaters emission rates in the SIP are consistent with the 40 CFR Part 60, Subpart QQQQ standard for wood heating devices. The standards are set by the EPA and apply to manufacturers of the wood heating devices. Any such device that is approved by the EPA should be allowed in the nonattainment area, this includes outdoor hydronic heaters. Existing residential and smaller commercial coal-fired devices are required to be removed by December of 2024 and new coal-fired devices are prohibited from installation within the nonattainment area.[20] Coal-fired devices currently installed can be subject to an in-use source test to demonstrate the device meets the standard of 18 g/h of total particulate matter. This standard should also be the criteria for new residential and smaller commercial coal-fired devices. The 18 g/h standard is consistent with 0.10 lbs/MMBtu (heat input) emission rate for a unit that is rated at 400,000 Btu/hr. The Titan II auger-fed coal boilers are rated at 440,000 Btu/hr (heat output) and have undergone testing through OMNI Test Labs; the same lab that derived emission rates for the DEC which are being used in the nonattainment area SIPs. The OMNI test conducted in 2011 demonstrated that auger-fed coal fired hydronic heaters are extremely efficient. Ranking

[19] Federal Register, Vol. 80, No.50, Monday, March 16, 2015. Pg. 13672.
[20] Section 7.7.5.1.2 "Device Requirements – wood-fired and coal-fired standards", Draft Serious SIP.

among the lowest emission rates for units tested. Emission rates of auger-fed coal-fired hydronic heaters (0.027g/MJ; **0.06 lbs/MMBtu[heat output basis]**) were consistent with EPA Certified Woodstoves (0.041 g/MJ; **0.10 lbs/MMBtu [heat output basis]**).[21] The DEC is aware that more efficient heating is better for the nonattainment area situation regardless of heating device. Acceptable standards for the installation of coal-fired units should be included within the proposed regulations. There should not only be a standard for the existing units referenced in the regulations but also an achievable emission rate and standards for new coal-fired units. While there are provisions for the department's approval contingency, it does not provide a target emission rate for respective devices and fuels that are not EPA certified.

Best Available Control Technologies (BACT)

The proposed SIP considers BACT for the major sources; however, authorization of the BACT determination is not finalized through the EPA. With an impending date to install BACT four years from the date of reclassification (i.e., June 9, 2021), there doesn't seem to be time for any technological changes to the community of major sources. Although the state is trying to accommodate the deadline for BACT implementation through creative agreements (e.g., Fort Wainwright), the DEC alternatively could provide justification that the implementation of BACT is both technologically and economically infeasible at this time. This option is available to the state through 40 CFR 51.1010 (3). The economically infeasible consideration is relevant due to the cost of implementation of sulfur controls on the major sources for its potential gain in $PM_{2.5}$ reduction (approx. $10 million for 1 $\mu g/m^3$ removed). A technologic infeasibility case could be considered on the basis that impending deadlines for BACT implementation is constrictive. The actual time it would take to design, build and implement sulfur controls for any facility cannot be accommodated in the time allotted. If either approach is accepted by the EPA, no further consideration would be necessary for BACT. UCM is also providing a justification for the use of a 0.25% coal-sulfur content as opposed to the 0.2% coal-sulfur content proposed by the DEC in the Serious SIP.

<u>Response</u>

As indicated in the Control Strategies chapter, the Department does not plan to require implementation of SO_2 controls at the Chena Power Plant due to the financial indicators provided by Aurora and allowed under Federal Register, Vol. 81, No.164, Wednesday August 24, 2016. pg. 58085. The Department finds that the financial indicators provided by Aurora are sufficient evidence to demonstrate that imposing add-on DSI controls on the existing coal-fired boilers would cause an adverse economic impact to Aurora. For more information see Appendix III.D.7.7 for Aurora's November 1, 2018 response to DEC's information request.

The Department notes the NOx controls proposed in this section are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC has

[21] OMNI-Test Laboratories, Inc. 2011. Measurement of Space-Heating Emissions. Prepared for FNSB. Retrieved from https://cleanairfairbanks.files.wordpress.com/2012/02/omni-space-heating-study-fairbanks-draft-report-rev-4.pdf

included with this Serious SIP, a final precursor demonstration as justification not to require NOx controls.

The Department acknowledges that the 0.2 percent sulfur content limit wasn't included as part of the BACT determination and therefore didn't go through EPA's top-down evaluation process. Instead it was established in the Control Strategies chapter as a method to limit SO_2 emissions in a reasonable way. The Department received multiple comments requesting that this limit be revised to 0.25 percent sulfur by weight. A 0.25 percent sulfur limit meets the Department's need to ensure no backsliding occurs and therefore the Department acquiesced to that request.

The Department is therefore requiring all coal delivered to stationary sources in the Fairbanks nonattainment area to have a gross as received sulfur content of no greater than a 0.25% by weight. This new coal sulfur requirement will need to be incorporated into Aurora's air quality permit.

Requiring the change in sulfur content to be implemented on an as-delivered-basis will allow the coal already stockpiled at the Chena Power Plant to be utilized and ensure a continuous supply of coal is available.

2b. Technological Infeasibility

Issue: BACT determination for Fort Wainwright (FWA) Central Heat and Power Plant (CHPP) is not justifiable considering the DEC's options under the 2016 $PM_{2.5}$ Implementation Rule.

Request: The option to determine BACT on FWA CHPP for SO_2 emissions is technologically infeasible due to time constraints is within DEC's authority. As such, a demonstration asserting that condition should be made.

Background:

BACT determination for the Fort Wainwright (FWA) Central Heat and Power Plant (CHPP) is arguably not justifiable per the requirements proposed in the draft Serious SIP. The Army installation was given two choices; either to retire the FWA CHPP or install and operate Dry Sorbent Injection (DSI) pollution control on the coal-fired boilers. As indicated, FWA is conducting a National Environmental Policy Act (NEPA) analysis to evaluate replacing the industrial coal-fired boilers which may take 2.5-3 years for a Record of Decision (ROD) [e.g., 2021 or 2022]. Since a determination captured in a ROD would come after the required installation date for BACT (i.e., June 9, 2021), the DEC is requesting an enforceable agreement to be made prior to the final submittal of the SIP (i.e., late 2019/early 2020). The agreement would be part of a Compliance Order by Consent (COBC) setting a date for either decommissioning the plant or installation of pollution controls. Realistically, whether the ROD determined the plant was to be decommissioned, alternative heating was proposed, or a do-nothing option was considered, the timeline for implementation of the agreement could be realized after DEC's expeditious attainment date of 2029.

Based on 40 CFR 51.1010 (3), the state may make a demonstration that any measure identified is "not technologically or economically feasible to implement in whole or in part by the end of the tenth calendar year following the effective date of the designation of the area, and may eliminate such whole or partial measure from further consideration under this paragraph." Since it is established that BACT implementation is not possible by June 9, 2021, it would seem reasonable to consider the option as technologically infeasible.

2c. Sulfur Content of Coal

Issue: Proposed BACT for coal-sulfur content of 0.2% will cut off access to tens of millions of tons of coal for UCM as well as pose a potential threat of fuel supply interruption for the coal fired power plants.

Request:

- Adopt a new standard of 0.25% based on semi-annual weighted averages of coal-sulfur content in shipments of coal within semi-annual periods corresponding to Facility Operating Report reporting periods.
- Include provisions or circumstances within the SIP when the imposed coal-sulfur limit can be relaxed.

Background:

The ADEC has proposed that Best Available Control Technology (BACT) for coal burning facilities in the nonattainment area is a coal-sulfur limit of 0.2% sulfur by weight. Usibelli Coal Mine (UCM) is the only source of commercial coal available to the coal-fired facilities within the Fairbanks North Star Borough fine particulate nonattainment area. The mine has limited ability to affect the sulfur content in the coal. There isn't a coal washing or segregating facility associated with UCM which could ensure a consistent coal-sulfur concentration. Current practice for providing low-sulfur coal to customers is identifying sulfur content of the resource through drilling and sampling efforts. However, no matter how much sampling is done, the ability to characterize the sulfur content of the coal actually mined is limited.

Within the millions of tons of coal resources available to UCM, there is a significant amount of coal with higher sulfur content than 0.2%; in fact, any limit proposed to the coal sulfur content is effectively cutting off access to tens of millions of tons of coal resources. As such, UCM proposes that the coal-sulfur limit be lowered to 0.25% on an as received basis (wet) as opposed to 0.2% as proposed by ADEC. The increase in coal-sulfur content will help with coal accessibility and availability over the next decade and still provides ADEC with a 37.5% reduction in the potential to emit based from the current limit of 0.4%.

The state was silent on how the measure was to be reported or considered within a regulatory context. The ADEC's standard permit condition for coal fired boilers (Standard Condition XIII) requires that the permittee report sulfur content of each shipment of fuel with the semi-annual Facility Operating Reports. UCM currently provides semi-annual reports to all customers which includes sulfur content of each shipment of coal along with the weighted average coal-sulfur content for the six-month period coinciding with the operating reports' reporting period. UCM proposes that the standard operating permit condition remain the same and that facilities continue to provide the state with the sulfur content of each shipment of fuel; in addition, the weighted average coal-sulfur content of the shipments received by the facility during the reporting period would be referenced in the operating report.

UCM would like the DEC to include circumstances when any imposed reduced coal-sulfur limit can be relaxed. Situations when relaxing the coal-sulfur limit will not impede attainment of the $PM_{2.5}$ standard should be considered when drafting the proposed regulations. As previously indicated, coal resources are effectively being cut off by the imposition of a reduced limit. An example when relaxing the coal-sulfur limit wouldn't impede attainment of the standard is if sulfur controls were acquired on a coal-fired facility. The state and the facility would, inevitably, work out an emission rate for the facility. The subsequent fuel-sulfur loading requirement would be established in order for the facility to meet their emission limit. If the fuel-sulfur loading requirement could be in excess of the coal-sulfur limit while still allowing the facility to meet the emission limit; that should qualify as a criteria to relax the limit. Another condition may be when the area comes into attainment with the $PM_{2.5}$ standard. Perhaps one of the aspects of a maintenance state implementation plan could be to remove or relax the imposed coal-sulfur limit on the basis that the impact from coal-sulfur is negligible to the area problem.

<u>Response</u>

The Department acknowledges that the 0.2 percent sulfur content limit wasn't included as part of the BACT determination and therefore didn't go through EPA's top-down evaluation process. Instead it was established in the Control Strategies chapter as a method to limit SO_2 emissions in a reasonable way. The Department received multiple comments requesting that this limit be revised to 0.25 percent sulfur by weight. A 0.25 percent sulfur limit meets the Department's need to ensure no backsliding occurs and therefore the Department acquiesced to that request.

The Department is therefore requiring all coal delivered to stationary sources in the Fairbanks nonattainment area to have a gross as received sulfur content of no greater than a 0.25% by weight. This new coal sulfur requirement will need to be incorporated into the air quality permits of the stationary sources in the Fairbanks nonattainment area.

With respect to the potential for changing the coal sulfur limit in the future, the Department has not added discussion in this Serious SIP of any future changes to control measures because it would be premature to do so. The Department acknowledges that when the area comes into attainment and a maintenance plan is developed, there may be opportunities to revisit control measures, including coal sulfur limits, consistent with any federal planning requirements in place at that time.

2d. Major Source Economic Infeasibility Justification

Issue: The DEC has the option to demonstrate the economic infeasibility of SO_2 BACT for major sources within the nonattainment area under 40 CFR 51.1010 (3) based on cost effectiveness. The most cost effective value for operating BACT controls on the community of major sources to remove 1 $\mu g/m^3$ of $PM_{2.5}$ is \$9,794,799 per year [See Table 7b].

Request:

- Define cost effectiveness as cost per 1 $\mu g/m^3$ of $PM_{2.5}$ for this exercise.
- Derive a cost per ton removed for each major source in the nonattainment area by adjusting operational load to represent actual SO_2 emissions in the spreadsheets for each facility provided within the appendices of the "Control Strategies" section of the draft serious SIP.
- Evaluate the cumulative annualized cost incurred by the community of major sources within the nonattainment area based on potential tons removed from implementing SO_2 BACT using actual emissions (instead of PTE).
- Correlate annualized cost of SO_2 BACT controls with results from the SO_2 Analysis section of the draft SIP (Section 7.8.12.5) to derive a cost/$\mu g/m^3$ mitigated from applying SO_2 control technologies.

Background:

Major stationary sources are a subgroup of emission sources that are given special consideration under nonattainment area provisions. Point sources with emissions greater than 70 tons per year of $PM_{2.5}$ or any individual precursor (NOx, SO_2, NH_3, VOCs) are evaluated for appropriate control. NOx and SO_2 were addressed on an emission unit specific basis in DEC's Best Available Control Technologies (BACT) determinations. The DEC's evaluation considered technical feasibility and estimates of emissions reductions to meet a defined emission limit. Operations at the facility's potentials to emit is used for the purpose of identifying a cost effectiveness for each technology in cost per ton removed.

The BACT analyses evaluate pollution control independent of the nonattainment area problem; it is simply triggered as a condition of an area defined as being in serious nonattainment of a pollutant standard. As described in the 2016 $PM_{2.5}$ Implementation Rule, the state can provide either a technologic or an economic infeasibility demonstration for control measures.[22] The argument must illustrate it is not technologically or economically feasible to implement the control measure by the end of the tenth calendar year (i.e., December 31, 2019 for the FNSB NAA) following the effective date of the designation of the area. UCM believes that there is enough evidence to substantiate that SO_2 controls on the community of major sources is economically infeasible.

<u>Economic Infeasibility Justification</u>

[22] 40 CFR 51.1010 (3)

The DEC has determined BACT is comprised of sulfur controls for major stationary sources. The DEC has also determined that sulfur controls are economically infeasible for one major source, silent on infeasibility for another, and partially economically infeasible for a couple of major sources within the NAA.[23] Per regulation, DEC has the authority to demonstrate that any measure identified is economically infeasible.[24] It is within the DEC's authority to determine that BACT for sulfur control is economically infeasible for the community of major sources in the NAA based on cost effectiveness.[25] If cost effectiveness is defined as cost per $\mu g/m^3$ removed, there is a clear justification to eliminate sulfur control measures from the community of major sources. The most cost effective value for operating BACT controls on the community of major sources to remove 1 $\mu g/m^3$ of $PM_{2.5}$ is $9,794,799 per year [See Table 7b].

<u>Annualized Cost of BACT Implementation</u>

The DEC derived cost effectiveness value in cost per ton removed is established through the implementation of the BACT analysis. The DEC preferred BACT controls and cost effectiveness value are referenced in Section 7.7.8 of the SIP.[26] Dry Sorbent Injection (DSI) is selected for the coal fired boilers with an 80% reduction in SO_2 and ULSD is suggested for GVEA's North Pole Plant and Zehnder Facility with a 99.7% removal rate for SO_2. Based on the Potential to Emit (PTE) of each facility, the state derives a cost effectiveness value for the sources.

Annualized cost to implement BACT for the community of major sources are based on operating scenarios for both PTE and actual emissions (2013)[27] from the facilities. The results are illustrated in Table 6a and 6b. The cost effectiveness value (cost/ton removed) is multiplied by the amount of pollution removed (tons) to derive an annual cost for BACT for each facility. The total annualized cost is the sum of the cumulative annual operating cost for the controls on all the major sources in the NAA. The annualized costs do not include the cost of fuel switching for smaller diesel engines, backup generators and boilers that are found on the campuses of certain facilities (e.g., UAF, FWA). The total annualized BACT implementation cost to operate at the PTEs is $49,296,062; annualized cost considering actual emissions is $20,843,332 (See Tables below).

Table 6a: BACT Annualized Costs Based on Potential To Emit

Facility	BACT (SO_2 Control)	SO_2 Reduction	SO_2 Emissions PTE[3]	SO_2 Reduction[3]	Cost/ton removed[2,3]	Annualized Cost
Units		(%)	(tpy)	(tpy)	($)	($)
Chena Power Plant	DSI	80	1,004.0	803.0	$ 7,495	$ 6,018,485
FWA	DSI	80	1,168.5	934.8	$ 10,329	$ 9,655,331
NPP-EU1	ULSD	99.7	1,486.4	1,482.0	$ 9,139	$ 13,543,998
NPP-EU2	ULSD	99.7	1,356.1	1,352.0	$ 9,233	$ 12,483,016
UAF	DSI	80	242.5	194.0	$ 11,578	$ 2,246,132
Zender	ULSD	99.7	598.6	597.0	$ 8,960	$ 5,349,120
Notes: See Below.					Total Annualized Cost	$ 49,296,082

[23] Section 7.7.8 of the draft Serious SIP
[24] 40 CFR 51.1010 (3)
[25] 40 CFR 51.1010 (3)(ii)
[26] Appendix III.D.7.07 Control Strategies: https://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip/
[27] Table 7.6-9 "2013 SO2 Episodic vs. Annual Average Point Source Emission (tons/day)"[Draft Serious SIP]ADEC

Table 6b: BACT Annualized Costs Based on Actual Emissions						
Facility	BACT (SO_2 Control)	SO_2 Reduction	SO_2 Emissions (Actual)[1,3]	SO_2 Reduction	Cost/ton removed[4]	Annualized Cost
Units		(%)	(tpy)	(tpy)	($)	($)
Chena Power Plant	DSI	80	711.8	569.4	$ 8,960	$ 5,101,824
FWA	DSI	80	766.5	613.2	$ 11,235	$ 6,889,302
NPP-EU1	ULS D	99.7	142.3	141.9	$ 12,169	$ 1,726,454
NPP-EU2	ULS D	99.7	422.3	421.0	$ 9,453	$ 3,980,026
UAF	DSI	80	219.0	175.2	$ 11,578	$ 2,028,466
Zender	ULS D	99.7	73.0	72.8	$ 15,351	$ 1,117,261
Notes:					Total Annualized Cost	$ 20,843,332

1 - Table 7.6-9 "2013 SO2 Episodic vs. Annual Average Point Source Emissions (tons/day)"
2 - Sectoin 7.7.8 of SIP
3 - BACT Spreadsheets (May 2019) in SIP for Listed Facilities; adjusted AE emission factor of 0.472 lbs-SO2/MMBtu referenced in BACT Section of SIP.
4 - Cost/ton removed after adjusting operational load in BACT Spreadsheets (May 2019) to reflect actual emissions; AE emission factor of 0.472 lbs-SO_2/MMBtu

Major source SO_2 Control Cost Effectiveness: Cost per µg/m^3 $PM_{2.5}$ Removed

The DEC provided an SO_2 analysis using the 2019 projected baseline inventory.[28] The DEC determined that major stationary sources were found to contribute significantly to $PM_{2.5}$ concentrations at the State Office Building (SOB) and the monitor adjacent to the Borough building (NCORE) in downtown Fairbanks. The impact at the monitors were 1.79 µg/m^3 and 1.70 µg/m^3 respectively.[29] The impact at the Hurst Road and North Pole Elementary (NPE) monitors were 0.04 µg/m^3 and 0.10 µg/m^3 respectively.

Assuming that an 80% removal of the point source emissions of SO_2 would translate to an 80% reduction to the impact from major sources of sulfur-based $PM_{2.5}$ at the monitors, the amount of $PM_{2.5}$ reduced at the SOB, NCORE, Hurst Road, and NPE monitors would be 1.43 µg/m^3, 1.36 µg/m^3, 0.03 µg/m^3, and 0.08 µg/m^3 respectively. Based on the total annualized cost for BACT controls using actual emissions ($20,843,332) the cost effectiveness value in cost per µg/m^3 of $PM_{2.5}$ removed is at the best, $14,555,400 per µg/m^3 removed and at the worst $651,354,137 per µg/m^3 removed (Table 7a). If the alternative approach to the SO_2 design value contribution from major sources is considered then the cost effectiveness at best is $9,794,799 per µg/m^3 and at worst is $19,299,382 per µg/m^3 (Table 7b).

Ironically, the cost per µg/m^3 removed is less at the SOB and NCORE sites where the projected design value is in compliance with the standard. The projected design value provided by the DEC for 2019 meet attainment at the SOB and NCORE sites which are of 29.72 µg/m^3 and 29.01 µg/m^3 respectively[30]; the attainment standard is 35 µg/m^3. The 2019 design values at the Hurst Road and NPE monitors were µg/m^3 and 36.48 µg/m^3, both clearly above the attainment standard of 35 µg/m^3. The impact from the major sources is less significant at the sites where the 2019 projected design value violates the standard.

Table 7a: Cost Effectiveness Based on Design Value Contribution SO_2 from Major Stationary Sources

[28] Section 7.8.12.5 of the draft Serious SIP
[29] Table 7.8-26. "Design value contribution from major stationary source SO_2".Draft Serious SIP.
[30] Table 7.8-29. "2019 FDV for Projected Baseline and Control Scenario Calculated against a 2013 Base year"

Site	Design Value Base Year 2013[1]	Projeced Design Value Year 2019[1]	Major Source Sulfur-Based Particulate Contribution[2]	BACT Reduction (80% of Direct Emissions)	BACT Reduction / Design Value 2019	Annualized BACT Cost per ug/m³ removed
Units	(ug/m³)	(ug/m³)	(ug/m³)	(ug/m³)	(%)	($)
State Office Building (SOB)	38.93	29.72	1.79	1.43	4.8%	$ 14,555,400
Fairbanks Borough Building (N	37.96	29.01	1.70	1.36	4.7%	$ 15,325,980
Hurst Road	131.63	104.81	0.04	0.03	0.0%	$ 651,354,137
North Pole Elementary (NPE)	45.3	36.48	0.10	0.08	0.2%	$ 260,541,655

Notes:
1 - Table 7.8-29 of Draft Serious SIP
2 - Table 7.8-26 of Draft Serious SIP

Table 7b: Cost Effectiveness Based on Alternative Approach to Design Value Contribution SO_2 from Major Stationary Sources

Site	Design Value Base Year 2013[1]	Projeced Design Value Year 2019[1]	Major Source Sulfur-Based Particulate Contribution[2]	BACT Reduction (80% of Direct Emissions)	BACT Reduction/Design Value 2019 x 100	Annualized BACT Cost per ug/m³ removed
Units	(ug/m³)	(ug/m³)	(ug/m³)	(ug/m³)	(%)	($)
State Office Building (SOB)	38.93	29.72	2.66	2.13	7.2%	$ 9,794,799
Fairbanks Borough Building (N	37.96	29.01	2.53	2.02	7.0%	$ 10,298,089
Hurst Road	131.63	104.81	1.55	1.24	1.2%	$ 16,809,139
North Pole Elementary (NPE)	45.3	36.48	1.35	1.08	3.0%	$ 19,299,382

Notes:
1 - Table 7.8-29 of Draft Serious SIP
2 - Table 7.8-27 of Draft Serious SIP

Fairbanks exceeds the fine particulate matter standard during winter months.[31] Control technology application on major stationary sources is permanent and transcends seasons. BACT for sulfur control on major sources is an annual solution to a wintertime problem. The application of SO_2 BACT is arguably an impractical effort. Where the pollutant concentration is either achieving or almost achieving the standard, the projected impact removed by application of BACT on the major sources is about 7% of the concentration. Since the standard is attained, removing 7% more of sulfur-based $PM_{2.5}$ for costs upward of $10 million dollars per μg/m³ seems impractical. There is a mechanism allotted within the 2016 $PM_{2.5}$ Implementation Rule for the DEC to provide a detailed written justification for eliminating, from further consideration, potential control measures for SO_2 on the community of major stationary sources based on cost ineffectiveness.

As such, UCM supports an economic infeasibility determination for the application of BACT on all major stationary sources within the nonattainment area.

Conclusion

In summary, UCM is thankful to have the opportunity to comment on the Serious Area SIP and the proposed regulations. UCM's main concerns expressed within these comments are the application of a common standard for solid fuel burning devices, the application of a workable coal-sulfur limit as BACT for the coal-fired facilities, and an economic infeasibility justification for sulfur controls for the community of major sources in the NAA. Included below are summaries highlighting key points of UCM's comments:

- BACT requirement for coal facilities to meet coal-sulfur content of 0.2% is being contested. UCMs requests a modified BACT requirement to 0.25% coal-sulfur (as received) evaluated

[31] Section 7.8.6 of the Draft Serious SIP

on a six-month weighted average using UCM analyses for each shipment.

- UCM is encouraging the DEC to include provisions or circumstances within the SIP when the imposed coal-sulfur limit can be relaxed without impact to the nonattainment area. As indicated, coal resources are effectively being cut off by the imposition of a reduced limit.
- A demonstration asserting that it is technologically infeasible to install BACT for SO_2 on the FWA CHPP due to time constraints is within the DEC's authority under the provisions of the 2016 $PM_{2.5}$ Implementation Rule and should be considered.
- UCM supports an economic infeasibility determination for the community of major sources based on the cost ineffectiveness of sulfur control technology in removing 1 $\mu g/m^3$ of sulfur-based $PM_{2.5}$ from major source SO_2 contribution.
- Solid fuel burning devices are not treated equally within the Serious Area SIP. A proposition for a common emission standard for those units that do not have EPA certification or standard to meet is encouraged. Those units with EPA standards should be allowed to operate within the NAA. Also, inclusion of emission standards and criteria for coal-fired home heating devices within the regulation is encouraged.

Response

As indicated in the Control Strategies chapter, the Department does not plan to require implementation of SO_2 controls at the Chena Power Plant due to the financial indicators provided by Aurora and allowed under Federal Register, Vol. 81, No.164, Wednesday August 24, 2016. pg. 58085. The Department finds that the financial indicators provided by Aurora are sufficient evidence to demonstrate that imposing add-on DSI controls on the existing coal-fired boilers would cause an adverse economic impact to Aurora. For more information see Appendix III.D.7.7 for Aurora's November 1, 2018 response to DEC's information request.

The Department notes the NOx controls proposed in this section are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC has included with this Serious SIP, a final precursor demonstration as justification not to require NOx controls.

The Department acknowledges that the 0.2 percent sulfur content limit wasn't included as part of the BACT determination and therefore didn't go through EPA's top-down evaluation process. Instead it was established in the Control Strategies chapter as a method to limit SO_2 emissions in a reasonable way. The Department received multiple comments requesting that this limit be revised to 0.25 percent sulfur by weight. A 0.25 percent sulfur limit meets the Department's need to ensure no backsliding occurs and therefore acquiesced to that request.

The Department is therefore requiring all coal delivered to stationary sources in the Fairbanks nonattainment area to have a gross as received sulfur content of no greater than a 0.25% by weight. This new coal sulfur requirement will need to be incorporated into the air quality permits for the stationary sources in the nonattainment area.

The Department notes that this change in sulfur content of the coal will not affect deliveries outside of the Fairbanks nonattainment area, allowing UCM to bring their higher sulfur content coal to market.

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
Air Permits Program

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION for Chena Power Plant Aurora Energy, LLC.

Prepared by: Aaron Simpson
Supervisor: James R. Plosay
Final Date: November 13, 2019

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Abbreviations/Acronyms

AAC ....Alaska Administrative Code
AAAQS ....Alaska Ambient Air Quality Standards
Department ....Alaska Department of Environmental Conservation
BACT ....Best Available Control Technology
CFB……………………Circulating Fluidized Bed
CFR. ....Code of Federal Regulations
Cyclones……………….Mechanical Separators
DFP……………………Diesel Particulate Filter
DLN...............................Dry Low NOx
DOC…………………...Diesel Oxidation Catalyst
EPA ....Environmental Protection Agency
ESP…………………….Electrostatic Precipitator
EU.................................Emission Unit
FITR…………………...Fuel Injection Timing Retard
GCPs…………………..Good Combustion Practices
HAP...............................Hazardous Air Pollutant
ITR…………………….Ignition Timing Retard
LEA……………………Low Excess Air
LNB……………………Low NOx Burners
MR&Rs ....Monitoring, Recording, and Reporting
NESHAPS ....National Emission Standards for Hazardous Air Pollutants
NSCR…………………Non-Selective Catalytic Reduction
NSPS ....New Source Performance Standards
ORL...............................Owner Requested Limit
PSD................................Prevention of Significant Deterioration
PTE................................Potential to Emit
RICE, ICE ....Reciprocating Internal Combustion Engine, Internal Combustion Engine
SCR ....Selective Catalytic Reduction
SIP ....Alaska State Implementation Plan
SNCR…………………Selective Non-Catalytic Reduction
ULSD ....Ultra Low Sulfur Diesel

Units and Measures

gal/hr..............................gallons per hour
g/kWh ....grams per kilowatt hour
g/hp-hr ....grams per horsepower hour
hr/day.............................hours per day
hr/yr ....hours per year
hp...................................horsepower
lb/hr ....pounds per hour
lb/MMBtu ....pounds per million British thermal units
lb/1000 gal ....pounds per 1,000 gallons
kW ....kilowatts
MMBtu/hr......................million British thermal units per hour
MMscf/hr.......................million standard cubic feet per hour
ppmv..............................parts per million by volume
tpy..................................tons per year

Pollutants

CO ....Carbon Monoxide
HAP...............................Hazardous Air Pollutant
NOx ....Oxides of Nitrogen
SO_2 ....Sulfur Dioxide
PM-2.5...........................Particulate Matter with an aerodynamic diameter not exceeding 2.5 microns
PM-10............................Particulate Matter with an aerodynamic diameter not exceeding 10 microns

1. INTRODUCTION

Chena Power Plant is a stationary source owned by Aurora Energy, LLC (Aurora) which consists of four boilers. Emission Units (EUs) 4 through 6, also identified as Chena 1, 2, and 3, are coal-fired overfeed traveling grate stokers with a maximum steam production rating of 50,000 lbs/hr each. Maximum design power production is 5 megawatts (MW) each. EU 4 was installed in 1954, while EUs 5 and 6 were installed in 1952. EU 7, also identified as Chena 5, is a coal-fired, spreader stoker boiler with a maximum steam production rating of 200,000 lbs/hr and maximum power production rating of 20 MW. Chena 5 was installed in 1970. Maximum coal consumption is 284,557 tons of coal per year, based on the capacities of EUs 4 through 7. Coal receiving and storage (handling) facilities are located on the north bank of the Chena River, and consist of a rail car receiving station, enclosed coal crusher (receiving building), open storage piles, conveyors, and elevators. Coal is transported by conveyors over the Chena River to the Chena Power Plant, located just above the south bank. In the late 1980's, the coal handling system was renovated.

In a letter dated April 24, 2015, the Alaska Department of Environmental Conservation (Department) requested the stationary sources expected to be major stationary sources in the particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers (PM-2.5) serious nonattainment area perform a voluntary Best Available Control Technology (BACT) review in support of the state agency's required SIP submittal once the nonattainment area is re-classified as a Serious PM-2.5 nonattainment area. The designation of the area as "Serious" with regard to nonattainment of the 2006 24-hour PM-2.5 ambient air quality standards was published in Federal Register Vol. 82, No. 89, May 10, 2017, pages 21703-21706, with an effective date of June 9, 2017. [1]

This report addresses the significant emissions units (EUs) listed in Operating Permit No. AQ0315TVP03, Revision 1. This report provides the Department's review of the BACT analysis for oxides of nitrogen (NOx) and sulfur dioxide (SO_2) emissions, which are precursor pollutants that can form PM-2.5 in the atmosphere post combustion.

The following sections review Chena Power Plant's BACT analysis for technical accuracy and adherence to accepted engineering cost estimation practices.

2. BACT EVALUATION

A BACT analysis is an evaluation of all available control options for equipment emitting the triggered pollutants and a process for selecting the best option based on feasibility, economics, energy, and other impacts. 40 CFR 52.21(b)(12) defines BACT as a site-specific determination on a case-by-case basis. The Department's goal is to identify BACT for the permanent EUs at Chena Power Plant that emit NOx and SO_2, establish emission limits which represent BACT, and assess the level of monitoring, recordkeeping, and reporting (MR&Rs) necessary to ensure Chena Power Plant applies BACT for the EUs. The Department based the BACT review on the five-step top-down approach set forth in Federal Register Volume 61, Number 142, July 23, 1996 (Environmental Protection Agency).

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[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 (https://dec.alaska.gov/air/anpms/comm/docs/2017-09391-CFR.pdf)

Table **A** present the EUs subject to BACT review.

Table A: Emission Units Subject to BACT Review

EU	Emission Unit Name	Emission Unit Description	Rating/Size	Installation or Construction Date
4	Chena 1 Coal Fired Boiler	Full Stream Baghouse Exhaust	76 MMBtu/hr	1954
5	Chena 2 Coal Fired Boiler	Full Stream Baghouse Exhaust	76 MMBtu/hr	1952
6	Chena 3 Coal Fired Boiler	Full Stream Baghouse Exhaust	76 MMBtu/hr	1952
7	Chena 5 Coal Fired Boiler	Full Stream Baghouse Exhaust	269 MMBtu/hr	1970

Five-Step BACT Determinations

The following sections explain the steps used to determine BACT for NOx and SO_2 for the applicable equipment.

Step 1 Identify All Potentially Available Control Technologies

The Department identifies all available control technologies for the EUs and the pollutant under consideration. This includes technologies used throughout the world or emission reductions through the application of available control techniques, changes in process design, and/or operational limitations. To assist in identifying available controls, the Department reviews available controls listed on the Reasonably Available Control Technology (RACT), BACT, and Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC). The RBLC is an EPA database where permitting agencies nationwide post imposed BACT for PSD sources. It is usually the first stop for BACT research. In addition to the RBLC search, the Department used several search engines to look for emerging and tried technologies used to control NOx and SO_2 emissions from equipment similar to those listed in Table A.

Step 2 Eliminate Technically Infeasible Control Technologies

The Department evaluates the technical feasibility of each control technology based on source specific factors in relation to each EU subject to BACT. Based on sound documentation and demonstration, the Department eliminates control technologies deemed technically infeasible due to physical, chemical, and engineering difficulties.

Step 3 Rank the Remaining Control Technologies by Control Effectiveness

The Department ranks the remaining control technologies in order of control effectiveness with the most effective at the top.

Step 4 Evaluate the Most Effective Controls and Document the Results as Necessary

The Department reviews the detailed information in the BACT analysis about the control efficiency, emission rate, emission reduction, cost, environmental, and energy impacts for each technology to decide the final level of control. The analysis must present an objective evaluation of both the beneficial and adverse energy, environmental, and economic impacts. A proposal to use the most effective option does not need to provide the detailed information for the less effective options. If cost is not an issue, a cost analysis is not required. Cost effectiveness for a control option is defined as the total net annualized cost of control divided by the tons of pollutant removed per year. Annualized cost includes annualized equipment purchase, erection, electrical, piping, insulation, painting, site preparation, buildings, supervision, transportation, operation, maintenance, replacement parts, overhead, raw materials, utilities, engineering, start-up costs, financing costs, and other contingencies related to the control option. Sections 3 and 4 present the Department's BACT Determinations for NOx and SO_2.

Step 5 Select BACT

The Department selects the most effective control option not eliminated in Step 4 as BACT for the pollutant and EU under review and lists the final BACT requirements determined for each EU in this step. A project may achieve emission reductions through the application of available technologies, changes in process design, and/or operational limitations. The Department reviewed Aurora's BACT analysis and made BACT determinations for NOx and SO_2 for the Chena Power Plant. These BACT determinations are based on the information submitted by Aurora in their analysis, information from vendors, suppliers, sub-contractors, RBLC, and an exhaustive internet search.

3. BACT DETERMINATION FOR NOx

The NOx controls proposed in this section are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC is planning to submit with the Serious SIP a final precursor demonstration as justification not to require NOx controls. Please see the precursor demonstration for NOx in the Serious SIP Modeling Chapter III.D.7.8. The PM2.5 NAAQS Final SIP Requirements Rule states if the state determines through a precursor demonstration that controls for a precursor gas are not needed for attaining the standard, then the controls identified as BACT/BACM or Most Stringent Measure for the precursor gas are not required to be implemented.[2] Final approval of the precursor demonstration is at the time of the Serious SIP approval.

Chena Power Plant has three existing 76 million British Thermal Units (MMBtu)/hr overfeed traveling grate stoker type boilers and one 269 MMBtu/hr spreader-stoker type boiler that burns coal to produce steam for stationary source-wide heating and power. The Department based its NOx assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by Golden Valley Electric Association (GVEA) for the North Pole Power Plant and Zehnder Facility, Aurora Energy, LLC (Aurora) for the Chena Power Plant, U.S. Army Corps of Engineers (US Army) for Fort Wainwright, and the University of Alaska Fairbanks (UAF) for the Fairbanks Campus Power Plant.

3.1 NOx BACT for the Industrial Coal-Fired Boilers

Possible NOx emission control technologies for coal fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 11.110

[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf

for Coal Combustion in Industrial Size Boilers and Furnaces. The search results for coal-fired boilers are summarized in Table 3-1.

Table 3-1. RBLC Summary of NOx Control for Industrial Coal-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Selective Catalytic Reduction	9	0.05 – 0.08
Selective Non-Catalytic Reduction	18	0.07 – 0.36
Low NOx Burners	18	0.07 – 0.3
Overfire Air	8	0.07 – 0.3
Good Combustion Practices	2	0.1 – 0.6

RBLC Review
A review of similar units in the RBLC indicates selective catalytic reduction, selective non-catalytic reduction, low NOx burners, overfire air, and good combustion practices are the principle NOx control technologies installed on industrial coal-fired boilers. The lowest NOx emission rate in the RBLC is 0.05 lb/MMBtu.

Step 1- Identification of NOx Control Technologies for the Industrial Coal-Fired Boilers
From research, the Department identified the following technologies as available for control of NOx emissions from the industrial coal-fired boilers:

(a) Selective Catalytic Reduction (SCR)[3]
SCR is a post-combustion gas treatment technique for reducing nitric oxide (NO) and nitrogen dioxide (NO_2) in the boiler exhaust stream to molecular nitrogen (N_2), water, and oxygen (O_2). In the SCR process, aqueous or anhydrous ammonia (NH_3) is injected into the flue gas upstream of a catalyst bed. The catalyst lowers the activation energy of the NOx decomposition reaction. NOx and NH_3 combine at the catalyst surface forming an ammonium salt intermediate, which subsequently decomposes to produce elemental N_2 and water. Theoretically, SCR systems can be designed for NOx removal efficiencies up close to 100 percent. In practice, commercial coal-, oil-, and natural gas–fired SCR systems are often designed to meet control targets of over 90 percent. However, the reduction may be less than 90 percent when SCR follows other NOx controls such as low NOx burners or flue gas recirculation that achieve relatively low emissions on their own. Challenges associated with using SCR on boilers include a narrow window of acceptable inlet and exhaust temperatures (500°F to 800°F), emission of NH_3 into the atmosphere (NH_3 slip) caused by non-stoichiometric reduction reaction, and disposal of depleted catalysts.

Based on review of the engineering study conducted by Stanley Consultants, the Department does not consider SCR to be a technically feasible control technology because of the historic flue gas temperatures at the Chena Power Plant. The Department reviewed past source test data which identified flue gas temperatures are approximately 300° F. SCR for NOx control has a narrow window of acceptable inlet and exhaust temperatures (500°F to 800°F).

[3] https://www3.epa.gov/ttncatc1/dir1/fscr.pdf

(b) Selective Non-Catalytic Reduction (SNCR)[4]
SNCR involves the non-catalytic decomposition of NOx in the flue gas to N_2 and water using reducing agents such as urea or NH_3. The process utilizes a gas phase homogeneous reaction between NOx and the reducing agent within a specific temperature window. The reducing agent must be injected into the flue gas at a location in the unit that provides the optimum reaction temperature and residence time. The NH_3 process (trade name-Thermal DeNOx) requires a reaction temperature window of 1,600°F to 2,200°F. In the urea process (trade name–NO_xOUT), the optimum temperature ranges between 1,600°F and 2,100°F. Expected NOx removal efficiencies are typically between 40 to 62 percent, according to the RBLC, or between 30 and 50 percent reduction, according to the EPA fact sheet (EPA-452/F-03-031). The Department reviewed past source test data which identified flue gas temperatures within the range of approximately 300° F, The Department does not consider SNCR to be a technically feasible control technology for the Chena Power Plant because SNCR it requires a reaction temperature window of 1,600°F to 2,200°F.

(c) Non-Selective Catalytic Reduction (NSCR)
NSCR simultaneously reduces NOx and oxidizes CO and hydrocarbons in the exhaust gas to N_2, carbon dioxide (CO_2), and water. The catalyst, usually a noble metal, causes the reducing gases in the exhaust stream (hydrogen, methane, and CO) to reduce both NO and NO_2 to N_2 at a temperature between 800°F and 1,200°F, below the expected temperature of the coal-fired boiler flue gas. NSCR requires a low excess O_2 concentration in the exhaust gas stream to be effective because the O_2 must be depleted before the reduction chemistry can proceed. NSCR is only effective with rich-burn gas-fired units that operate at all times with an air/fuel ratio controller at or close to stoichiometric conditions. Coal-fired boilers operate under conditions far more fuel-lean than required to support NSCR. The Department's research did not identify NSCR as a control technology used to control NOx emissions from large coal fired boilers installed at any facility after 2005. The Department does not consider NSCR a technically feasible control technology for the industrial coal-fired boilers.

(d) Low NOx Burners (LNBs)
Using LNBs can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature. Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one installation to another. Typical reductions range from 40% - 60% but under certain conditions, higher reductions are possible. Air staging or two-stage combustion, is generally described as the introduction of overfire air into the boiler or furnace. Overfire air is the injection of air above the main combustion zone. As indicated by EPA's AP-42, LNBs are applicable to tangential and wall-fired boilers of various sizes but are not applicable to other boiler

[4] https://www3.epa.gov/ttncatc1/dir1/fsncr.pdf

types such as cyclone furnaces or stokers. The Department does not consider LNBs a technically feasible control technology for stoker type coal-fired boilers.

(e) Circulating Fluidized Bed (CFB)
In a fluidized bed combustor, fuel is introduced to a bed of either sorbent (limestone) or inert material (usually sand) that is fluidized by an upward flow of air. This upward air flow allows for better mixing of the gas and solids to create a better heat transfer and chemical reactions. Combustion takes place in the bed at a lower temperature than other boiler types which lowers the formation of thermally generated NOx. The Department does not consider CFB a technically feasible control technology to retrofit existing coal-fired boilers. For the purposes of this report, a control technology does not include passive control measures that act to prevent pollutants from forming or the use of combustion or other process design features or characteristics. The Department does not consider CFB a technically feasible control technology to retrofit the existing coal-fired boilers.

(f) Low Excess Air (LEA)
Boiler operation with low excess air is considered an integral part of good combustion practices because this process can maximize the boiler efficiency while controlling the formation of NOx. Boilers operated with five to seven percent excess air typically have peak NOx formation from both peak combustion temperatures and chemical reactions. At both lower and higher excess air concentrations the formation of NOx is reduced. At higher levels of excess air, an increase in the formation of CO occurs. CO can increase exponentially at very high levels of excess air and the combustion efficiency is greatly reduced. As a result, the preference is to reduce excess air such that both NOx and CO generation is minimized and the boiler efficiency is optimized. Only one RLBC entry identified low excess air technology as a NOx control alternative for a mass-feed stoker designed boiler. Boilers are regularly designed to operate with low excess air as described in the previous LNB discussion. The Department considers LEA a technically feasible control technology for the industrial coal-fired boilers.

(g) Good Combustion Practices (GCPs)
GCPs typically include the following elements:

1. Sufficient residence time to complete combustion;
2. Providing and maintaining proper air/fuel ratio;
3. High temperatures and low oxygen levels in the primary combustion zone; and
4. High enough overall excess oxygen levels to complete combustion and maximize thermal efficiency.

Combustion efficiency is dependent on the gas residence time, the combustion temperature, and the amount of mixing in the combustion zone. GCPs are accomplished primarily through combustion chamber design as it relates to residence time, combustion temperature, air-to-fuel mixing, and excess oxygen levels. The Department considers GCPs a technically feasible control option for the coal-fired boilers.

(h) Fuel Switching

This evaluation considers retrofit of existing coal-fired boilers. It is assumed that use of another type of coal would not reduce NOx emissions. Therefore, the Department does not consider the use of an alternate fuel to be a technically feasible control technology for the industrial coal-fired boilers.

(i) Steam / Water Injection
Steam/water injection into the combustion zone reduces the firing temperature in the combustion chamber and has been traditionally associated with reducing NOx emissions from gas combustion turbines but not coal-fired boilers. In addition, steam/water has several disadvantages, including increases in carbon monoxide and un-burned hydrocarbon emissions and increased fuel consumption. Further, the Department found that steam or water injection is not listed in the EPA RBLC for use in any coal-fired boilers. Therefore, the Department does not consider steam or water injection to be a technically feasible control option for the existing coal-fired boilers.

(j) Reburn
Reburn is a combustion hardware modification in which the NOx produced in the main combustion zone is reduced in a second combustion zone downstream. This technique involves withholding up to 40 percent (at full load) of the heat input to the main combustion zone and introducing that heat input above the top row of burners to create a reburn zone. Reburn fuel (natural gas, oil, or pulverized coal) is injected with either air or flue gas to create a fuel-rich zone that reduces the NOx created in the main combustion zone to nitrogen and water vapor. The fuel-rich combustion gases from the reburn zone are completely combusted by injecting overfire air above the reburn zone. Reburn may be applicable to many boiler types firing coal as the primary fuel, including tangential, wall-fired, and cyclone boilers. However, the application and effectiveness are site-specific because each boiler is originally designed to achieve specific steam conditions and capacity which may be altered due to reburn. Commercial experience is limited; however, this limited experience does indicate NOx reduction of 50 to 60 percent from uncontrolled levels may be achieved. Reburn combustion control would require significant changes to the design of the existing boilers. Therefore, the Department does not consider reburn to be a technically feasible control technology to retrofit the existing industrial coal-fired boilers.

Step 2 - Elimination of Technically Infeasible NOx Control Options for Coal-Fired Boilers
As explained in Step 1 of Section 3.1, the Department does not consider SCR, SNCR, NSCR, low NOx burners, circulating fluidized beds, fuel switching, steam/water injection, or reburn as technically feasible technologies to control NO_x emissions from existing industrial coal-fired boilers.

Step 3 - Ranking of Remaining NOx Control Technologies for Coal-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of NOx emissions from the coal-fired boilers:

(a)	Good Combustion Practices	(Less than 40% Control)
(b)	Low Excess Air	(10% - 20% Control)

Step 4 - Evaluate the Most Effective Controls

Aurora BACT Proposal

Aurora provided an economic analysis for the installation of SCR on all four boilers combined (EUs 4 through 7). Aurora also provided economic analyses for the installation of SNCR on the three 76 MMBtu/hr boilers (EUs 4 through 6), the 269 MMBtu/hr boiler (EU 7), and all four boilers combined (EUs 4 through 7). A summary of the analyses is shown in Table 3-2.

Table 3-2. Aurora Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR (EUs 4 – 7)	784	564	$73,069,750	$15,994,554	$28,347
SNCR (EUs 7)	342	103	$2,792,684	$784,066	$7,649
SNCR (EUs 4 – 6)	439	132	$4,906,782	$1,589,578	$12,059
SNCR (EUs 4 – 7)	781	234	$7,699,466	$2,373,645	$10,130

Aurora's economic analysis indicates the level of NOx reduction does not justify the use of SCR or SNCR for the coal-fired boilers based on the excessive cost per ton of NOx removed per year.

Aurora proposes the following as BACT for NOx emissions from the coal-fired boilers:

(a) NOx emissions from the operation of the coal-fired boilers will be controlled with existing combustion controls;

(b) NOx emissions from the coal-fired boilers will not exceed 0.36 lb/MMBtu; and

(c) Initial compliance with the proposed NOx emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

Department Evaluation of BACT for NOx Emissions from the Industrial Coal-Fired Boilers

The Department revised the cost analyses provided by Aurora for the installation of SCR and SNCR using the cost estimating procedures identified in EPA's May 2016 Air Pollution Control Cost Estimation Spreadsheets for Selective Catalytic Reduction[5] and Selective Non-Catalytic Reduction,[6] using the unrestricted potential to emit of the four coal-fired boilers, a baseline emission rate of 0.402 lb NOx/MMBtu,[7] a retrofit factor of 1.5 for projects requiring a difficult retrofit, a NOx removal efficiency of 90% and 50% for SCR and SNCR respectively, and a 20 year equipment life. A summary of the analysis is shown below:

5 https://www3.epa.gov/ttn/ecas/docs/scr_cost_manual_spreadsheet_2016_vf.xlsm
6 https://www3.epa.gov/ttn/ecas/docs/sncr_cost_manual_spreadsheet_2016_vf.xlsm
7 Emission rate averaged from two most recent NOx and SO_2 source tests accepted by the Department which occurred on November 19, 2011 and July 12, 2019.

Table 3-3. Department Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
SCR	864	778	$26,273,791	$3,275,209	$4,208
SNCR	864	432	$5,887,957	$986,303	$2,281
Capital Recovery Factor = 0.0802 (5.0% interest rate for a 20 year equipment life)					

Although the Department finds the cost effectiveness values stated in Table 3-3 to be economically feasible, based on review of the engineering study conducted by Stanley Consultants, the Department does not consider SCR or SNCR to be technically feasible control technologies because of the historic flue gas temperatures at the Chena Power Plant. The Department reviewed past source test data which identified flue gas temperatures are approximately 300^{o} F.

Step 5 - Selection of NOx BACT for the Industrial Coal-Fired Boilers

The Department's finding is that BACT for NOx emissions from the coal-fired boilers is as follows:

(a) NOx emissions from EUs 4 through 7 shall be controlled by maintaining good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation;

(b) NOx emissions from DU EUs 4 through 7 shall not exceed 0.402 lb/MMBtu averaged over a 3-hour period; and

(c) Initial compliance with the proposed NOx emission rate will be demonstrated by conducting a performance test to obtain an emission rate.

Table 3-4 lists the proposed NOx BACT determination for this facility along with those for other coal-fired boilers in the Serious PM-2.5 nonattainment area.

Table 3-4. Comparison of NOx BACT for Coal-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	6 Coal-Fired Boilers	1,380 MMBtu/hr	0.06 lb/MMBtu[8]	Selective Catalytic Reduction
UAF	Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.04 lb/MMBtu[9]	Selective Catalytic Reduction
Chena	4 Coal-Fired Boilers	497 MMBtu/hr	0.402 lb/MMBtu[7]	Good Combustion Practices

4. BACT DETERMINATION FOR SO_2

The Department based its SO_2 assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by GVEA for the North Pole Power

[8] Calculated using a 90% NOx control efficiency for SCR with uncontrolled emission factor from AP-42 Table 1.1-3 for spreader stoker sub-bituminous coal (8.8 lb NOx/ton) and converted to lb/MMBtu using heat value for Usibelli Coal of 7,560 Btu/lb, http://www.usibelli.com/coal/data-sheet.

[9] Calculated using a 80% NOx control efficiency for SCR with uncontrolled emission rate from 40 C.F.R. 60.44b(l)(1) [NSPS Subpart Db].

Plant and Zehnder Facility, Aurora for the Chena Power Plant, US Army for Fort Wainwright, and UAF for the Combined Heat and Power Plant.

4.1 SO_2 BACT for the Industrial Coal-Fired Boilers

Possible SO_2 emission control technologies for coal-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 11.110, Coal Combustion in Industrial Size Boilers and Furnaces. The search results for the coal-fired boilers are summarized in Table 4-1.

Table 4-1. RBLC Summary of SO_2 Control for Industrial Coal-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Flue Gas Desulfurization / Scrubber / Spray Dryer	10	0.06 – 0.12
Limestone Injection	10	0.055 – 0.114
Low Sulfur Coal	4	0.06 – 1.2

RBLC Review
A review of similar units in the RBLC indicates flue gas desulfurization and low sulfur coal are the principle SO_2 control technologies installed on industrial coal-fired boilers. The lowest SO_2 emission rate in the RBLC is 0.055 lb/MMBtu.

Step 1- Identification of SO_2 Control Technology for the Coal-Fired Boilers
From research, the Department identified the following technologies as available for the control of SO_2 emissions from the industrial coal-fired boilers:

(a) Wet Scrubbers
Post combustion flue gas desulfurization techniques can remove SO_2 formed during combustion by using an alkaline reagent to absorb SO_2 in the flue gas. Flue gasses can be treated using wet, dry, or semi-dry desulfurization processes. In the wet scrubbing system, flue gas is contacted with a solution or slurry of alkaline material in a vessel providing a relatively long residence time. The SO_2 in the flue reacts with the alkali solution or slurry by adsorption and/or absorption mechanisms to form liquid-phase salts. These salts are dried to about one percent free moisture by the heat in the flue gas. These solids are entrained in the flue gas and carried from the dryer to a PM collection device, such as a baghouse.

The lime and limestone wet scrubbing process uses a slurry of calcium oxide or limestone to absorb SO_2 in a wet scrubber. Control efficiencies in excess of 91 percent for lime and 94 percent for limestone over extended periods are possible. Sodium scrubbing processes generally employ a wet scrubbing solution of sodium hydroxide or sodium carbonate to absorb SO_2 from the flue gas. Sodium scrubbers are generally limited to smaller sources because of high reagent costs and can have SO_2 removal efficiencies of up to 96.2 percent. The double or dual alkali system uses a clear sodium alkali solution for SO_2 removal followed by a regeneration step using lime or limestone to recover the sodium alkali and produce a calcium sulfite and sulfate sludge. SO_2 removal efficiencies of 90 to

96 percent are possible. The Department considers flue gas desulfurization with a wet scrubber a technically feasible control technology for the industrial coal-fired boilers.

(b) Spray Dry Absorbers (SDA)
In SDA systems, an aqueous sorbent slurry with a higher sorbent ratio than that of a wet scrubber is injected into the hot flue gases. As the slurry mixes with the flue gas, the water is evaporated and the process forms a dry waste which is collected in a baghouse or electrostatic precipitator. The Department considers flue gas desulfurization with an SDA system a technically feasible control technology for the industrial coal-fired boilers.

(c) Dry Sorbent Injection (DSI)
DSI systems pneumatically inject a powdered sorbent directly into the furnace, the economizer, or the downstream ductwork depending on the temperature and the type of sorbent utilized. The dry waste is removed using a baghouse or electrostatic precipitator. Spray drying technology is less complex mechanically, and no more complex chemically, than wet scrubbing systems. The main advantages of the spray dryer is that this technology avoids two problems associated with wet scrubbing, corrosion and liquid waste treatment. Spray dry scrubbers are mostly used for small to medium capacity boilers and are preferable for retrofits. The Department considers flue gas desulfurization with DSI a technically feasible control technology for the industrial coal-fired boilers.

(d) Low Sulfur Coal
Aurora purchases coal from the Usibelli Coal Mine located in Healy, Alaska. This coal mine is located 115 miles south of Fairbanks. The coal mined at Usibelli is sub-bituminous coal and has a relatively low sulfur content with guarantees of less than 0.4 percent by weight. Usibelli Coal Data Sheets indicate a range of 0.08 to 0.28 percent Gross As Received (GAR) percent Sulfur (%S). According to the U.S. Geological Survey, coal with less than one percent sulfur is classified as low sulfur coal. The Department considers the use of low sulfur coal a technically feasible control technology for the industrial coal-fired boilers.

(e) Good Combustion Practices (GCPs)
The theory of GCPs was discussed in detail in the NOx BACT for the industrial coal-fired boilers and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control option for the industrial coal-fired boilers.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for Coal-Fired Boilers
All identified control devices are technically feasible for the industrial coal-fired boilers.

Step 3 - Rank the Remaining SO_2 Control Technologies for Industrial Coal-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of SO_2 emissions from the coal-fired industrial boilers:

(a)	Wet Scrubbers	(99% Control)
(b)	Spray Dry Absorbers	(90% Control)
(c)	Dry Sorbent Injection (Duct Sorbent Injection)	(50 – 80% Control)

(d) Low Sulfur Coal (30% Control)
(e) Good Combustion Practices (Less than 40% Control)

Step 4 - Evaluate the Most Effective Controls

Aurora BACT Proposal

Aurora provided an economic analysis of the installation of wet and dry scrubber systems. A summary of the analysis is shown below:

Table 4-2. Aurora Economic Analysis for Technically Feasible SO_2 Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Wet Scrubber (Limestone Forced Oxidation)	830	415	$88,476,054	???	$74,146
Spray Dry Absorber (Lime Spray Dryer)	830	614	$74,161,357	???	???
Dry Sorbent Injection	830	332	$32,500,898	$9,129,760	$27,493
Capital Recovery Factor = 0.1627% of total capital investment (10% for a 10 year life cycle)					

Aurora contends that the economic analysis indicates the level of SO_2 reduction does not justify the use of wet scrubbers, semi-dry scrubbers, or dry scrubber systems (dry-sorbent injection) for the coal-fired boilers based on the excessive cost per ton of SO_2 removed per year.

Aurora proposes the following as BACT for SO_2 emissions from the coal-fired boilers:

(a) SO_2 emissions from the coal-fired boilers will be controlled by burning low sulfur coal at all times the boilers are in operation; and

(b) SO_2 emissions from the coal-fired boilers will not exceed 0.39 lb/MMBtu.

Department Evaluation of BACT for SO_2 Emissions from Industrial Coal-Fired Boilers

The Department revised the cost analysis provided for the installation of wet scrubbers, semi-dry scrubbers (spray dry absorbers), and dry scrubbers (dry sorbent injection) using the combined unrestricted potential to emit for the four coal-fired boilers, a baseline emission rate of 0.301 lb SO_2/MMBtu,[7] a retrofit factor of 1.5 for a difficult retrofit, a SO_2 removal efficiency of 99%, 90% and 80% for wet scrubbers, spray dry absorbers and dry sorbent injection respectively, an interest rate of 5.0% (current bank prime interest rate), and a 15 year equipment life. A summary of the analysis is shown below:

Table 4-3. Department Economic Analysis for Technically Feasible SO_2 Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
Wet Scrubber	653	646	$55,886,469	$10,232,462	$15,838
Spray Dry Absorbers	653	653	$50,846,544	$10,009,344	$17,042

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
Dry Sorbent Injection	653	522	$20,604,000	$5,056,994	$9,686
Capital Recovery Factor = 0.0963 (5.0% interest rate for a 15 year equipment life)					

The Department's economic analysis indicates the level of SO_2 reduction justifies the use of dry sorbent injection as BACT for the coal-fired boilers located in the Serious PM-2.5 nonattainment area.

Step 5 - Selection of SO_2 BACT for the Industrial Coal-Fired Boilers
The Department's finding is that BACT for SO_2 emissions from the coal-fired boilers is as follows:

(a) SO_2 emissions from EUs 4 through 7 shall be controlled by operating and maintaining dry sorbent injection at all times the units are in operation;

(b) SO_2 emissions from EUs 4 through 7 shall not exceed 0.10 lb/MMBtu[10] averaged over a 3-hour period; and

(c) Initial compliance with the SO_2 emission rate for the coal-fired boilers will be demonstrated by conducting a performance test to obtain an emission rate.

Table 4-4 lists the proposed SO_2 BACT determination for this facility along with those for other coal-fired boilers in the Serious PM-2.5 nonattainment area.

Table 4-4. Comparison of SO_2 BACT for Coal-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	6 Coal-Fired Boilers	1380 MMBtu/hr (combined)	0.12 lb/MMBtu	Dry Sorbent Injection Limited Operation Low Sulfur Coal
UAF	Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.10 lb/MMBtu	Dry Sorbent Injection Limestone Injection Low Sulfur Coal
Chena	4 Coal-Fired Boilers	497 MMBtu/hr (combined)	0.10 lb/MMBtu[10]	Dry Sorbent Injection Low Sulfur Coal

[10] BACT limit selected after evaluating existing emission limits in the RBLC database for coal-fired boilers, taking into account previous source test data from the Chena Power Plant and actual emissions data from other sources employing similar types of controls, using site specific vendor quotes provided by Stanley Consultants, and in-line with EPA's pollution control Fact Sheets while keeping in mind that BACT limits must be achievable at all times.

5. BACT DETERMINATION SUMMARY

Table 5-1. Proposed NOx BACT Limits

EU ID	Description	Rating/Size	Proposed BACT Limit	Proposed BACT Control
4	Chena 1 Coal Fired Boiler	76 MMBtu/hr	0.402 lb/ MMBtu	Good Combustion Practices
5	Chena 2 Coal Fired Boiler	76 MMBtu/hr		
6	Chena 3 Coal Fired Boiler	76 MMBtu/hr		
7	Chena 5 Coal Fired Boiler	269 MMBtu/hr		

Table 5-2. Proposed SO_2 BACT Limits

EU ID	Description	Rating/Size	Proposed BACT Limit	Proposed BACT Control
4	Chena 1 Coal Fired Boiler	76 MMBtu/hr	0.10 lb/MMBtu	Dry Sorbent Injection Low Sulfur Coal
5	Chena 2 Coal Fired Boiler	76 MMBtu/hr		
6	Chena 3 Coal Fired Boiler	76 MMBtu/hr		
7	Chena 5 Coal Fired Boiler	269 MMBtu/hr		