RACT Evaluation Report –Gadsby Power Plant

UTAH $PM_{2.5}$ SIP RACT

Salt Lake City Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

October 1, 2014

Company: Pacificorp Energy - Gadsby Pow
Site ID: 10355
Project: PM10 SIP
Date: 3/17/2015

County FIPS	Category NAICS	NAICS	SIC	Site ID
35	3	221119	4911	10355
35	3	221119	4911	10355
35	3	221119	4911	10355
35	3	221119	4911	10355
35	3	221119	4911	10355
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ver Plant

Site Name	Comp ID	Process ID	Process Code
Pacificorp Energy - Gadsby Power Plant	4025	1	a
Pacificorp Energy - Gadsby Power Plant	9143	1	a
Pacificorp Energy - Gadsby Power Plant	9144	1	a
Pacificorp Energy - Gadsby Power Plant	13689	1	a
Pacificorp Energy - Gadsby Power Plant	13690	1	a
Pacificorp Energy - Gadsby Power Plant	13691	1	a
Pacificorp Energy - Gadsby Power Plant	13692	1	a
Pacificorp Energy - Gadsby Power Plant	174520	1	a
Pacificorp Energy - Gadsby Power Plant	174521	1	a
Pacificorp Energy - Gadsby Power Plant	174522	1	a
Pacificorp Energy - Gadsby Power Plant	176981	1	a

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Component Description	Material or Fuel	Component SCC	ID	Height
Utility Boiler	Natural Gas	10100604	2942	250
Utility Boiler	Natural Gas	10100604	2943	250
Utility Boiler	Natural Gas	10100604	1280	250
Cooling tower for unit 1	Cooling Water	30600701	939205	10
Cooling tower for unit 2	Cooling Water	30600701	939206	10
Cooling tower for unit 3	Cooling Water	30600701	939207	10
Emergency Generator Diesel Engine	Diesel	20200102	174835	10
Gas Turbine	Natural Gas	20100201	20693	81
Gas Turbine	Natural Gas	20100201	20694	81
Gas Turbine	Natural Gas	20100201	20695	81
Black Start Generator	Diesel	20200102	174836	10

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Utility Boiler	Natural Gas	10100604	2943	250
Utility Boiler	Natural Gas	10100604	1280	250
Cooling tower for unit 1	Cooling Water	30600701	939205	10
Cooling tower for unit 2	Cooling Water	30600701	939206	10
Cooling tower for unit 3	Cooling Water	30600701	939207	10
Emergency Generator Diesel Engine	Diesel	20200102	174835	10
Gas Turbine	Natural Gas	20100201	20693	81
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Cooling tower for unit 2	Cooling Water	30600701	939206	10
Cooling tower for unit 3	Cooling Water	30600701	939207	10
Emergency Generator Diesel Engine	Diesel	20200102	174835	10
Gas Turbine	Natural Gas	20100201	20693	81
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Stack					Location			
Diameter	Temp	Flow	Area	Velocity	Lat	Long	Hrs/Day	Days/Wk
11	258	5512	95.03318	58	40.76861	-111.9292	24	7
11	244	5987	95.03318	63	40.76861	-111.9292	24	7
11	258	6555	95.03318	68.98	40.76861	-111.9292	24	7
0	72	0	0	0	40.76861	-111.9292	24	7
0	72	0	0	0	40.76861	-111.9292	24	7
0	72	0	0	0	40.76861	-111.9292	24	7
1	72	12	0.785398	15.28	40.76861	-111.9292	1	1
12	828	9852	113.0973	87.11	40.76861	-111.9292	24	7
12	828	9852	113.0973	87.11	40.76861	-111.9292	24	7
12	828	9852	113.0973	87.11	40.76861	-111.9292	24	7
1	72	12	0.785398	15.28	40.76861	-111.9292	1	1

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0	72	0	0	0	40.76861	-111.9292	24	7
1	72	12	0.785398	15.28	40.76861	-111.9292	1	1
12	828	9852	113.0973	87.11	40.76861	-111.9292	24	7
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12	828	9852	113.0973	87.11	40.76861	-111.9292	24	7
1	72	12	0.785398	15.28	40.76861	-111.9292	1	1

Temporal Operating Information								
Wks/Yr	Hrs/Yr	% Jan	% Feb	% Mar	% Apr	% May	% Jun	% Jul
52	492	0	0	6.77	0	0	8.41	50.87
52	674	0	0	4.73	0	0	6.09	48.38
52	1000	0	0.05	0.18	0.32	0	13.08	29.92
52	492	0	0	6.77	0	0	8.41	50.87
52	674	0	0	4.73	0	0	6.09	48.38
52	1000	0	0.05	0.18	0.32	0	13.08	29.92
52	12	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	2322	5.56	2.51	13.21	4.84	7.31	16.54	19.19
52	1987	6.21	2.65	14.93	5.16	6.75	15.89	18.75
52	2151	5.96	3.07	13.54	5.23	4.48	15.24	19.61
52	25	8.33	8.33	8.33	8.33	8.33	8.33	8.33

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Temporal Operating Information								
Wks/Yr	Hrs/Yr	% Jan	% Feb	% Mar	% Apr	% May	% Jun	% Jul
52	1316	0	0	0	0	0	12.23	21.53
52	1844	0	0	0	0	0	12.27	20.38
52	2969	0	0	0	0	0.88	11.48	15.26
52	1316	0	0	0	0	0	12.23	21.53
52	1844	0	0	0	0	0	12.27	20.38
52	2969	0	0	0	0	0.88	11.48	15.26
52	12	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	25	8.33	8.33	8.33	8.33	8.33	8.33	8.33

Temporal Operating Information								
Wks/Yr	Hrs/Yr	% Jan	% Feb	% Mar	% Apr	% May	% Jun	% Jul
52	1316	0	0	0	0	0	12.23	21.53
52	1844	0	0	0	0	0	12.27	20.38
52	2969	0	0	0	0	0.88	11.48	15.26
52	1316	0	0	0	0	0	12.23	21.53
52	1844	0	0	0	0	0	12.27	20.38
52	2969	0	0	0	0	0.88	11.48	15.26
52	12	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	25	8.33	8.33	8.33	8.33	8.33	8.33	8.33

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Wks/Yr	Hrs/Yr	% Jan	% Feb	% Mar	% Apr	% May	% Jun	% Jul
52	1316	0	0	0	0	0	12.23	21.53
52	1844	0	0	0	0	0	12.27	20.38
52	2969	0	0	0	0	0.88	11.48	15.26
52	1316	0	0	0	0	0	12.23	21.53
52	1844	0	0	0	0	0	12.27	20.38
52	2969	0	0	0	0	0.88	11.48	15.26
52	12	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	25	8.33	8.33	8.33	8.33	8.33	8.33	8.33

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Wks/Yr	Hrs/Yr	% Jan	% Feb	% Mar	% Apr	% May	% Jun	% Jul
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52	1844	0	0	0	0	0	12.27	20.38
52	2969	0	0	0	0	0.88	11.48	15.26
52	1316	0	0	0	0	0	12.23	21.53
52	1844	0	0	0	0	0	12.27	20.38
52	2969	0	0	0	0	0.88	11.48	15.26
52	12	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	25	8.33	8.33	8.33	8.33	8.33	8.33	8.33

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Wks/Yr	Hrs/Yr	% Jan	% Feb	% Mar	% Apr	% May	% Jun	% Jul
52	1316	0	0	0	0	0	12.23	21.53
52	1844	0	0	0	0	0	12.27	20.38
52	2969	0	0	0	0	0.88	11.48	15.26
52	1316	0	0	0	0	0	12.23	21.53
52	1844	0	0	0	0	0	12.27	20.38
52	2969	0	0	0	0	0.88	11.48	15.26
52	12	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	25	8.33	8.33	8.33	8.33	8.33	8.33	8.33

PM10	PM2.5	SO2
12.254	8.970	0.809

% Aug	% Sep	% Oct	% Nov	% Dec	Permit Status	PM10	PM2.5	SO2
33.94	0	0	0	0	Yes	0.811	0.811	0.065
31.42	9.39	0	0	0	Yes	1.229	1.229	0.098
42.06	14.39	0	0	0	Yes	2.184	2.184	0.176
33.94	0	0	0	0	Yes	0.854	0.000	
31.42	9.39	0	0	0	Yes	0.915	0.000	
42.06	14.39	0	0	0	Yes	1.516	0.000	
8.33	8.33	8.33	8.33	8.33	Yes	0.004	0.004	0.003
13.66	7.06	3.31	3.39	3.4	Yes	1.678	1.678	0.154
16.12	4.97	1.32	3.08	4.16	Yes	1.419	1.419	0.130
15.78	5.42	3.96	4.11	3.61	Yes	1.609	1.609	0.148
8.33	8.33	8.33	8.33	8.33	Yes	0.037	0.037	0.035

bles included

PM10	PM2.5	SO2
114.270	93.386	10.100

Does the 2019 True-Up In

% Aug	% Sep	% Oct	% Nov	% Dec	Permit Status	PM10	PM2.5	SO2
23.47	25.17	13.23	4.37	0	Yes	4.50	4.50	0.24
18	20.8	17.59	10.95	0.03	Yes	7.28	7.28	0.39
15.9	14.8	15.07	14.58	12.03	Yes	14.95	14.95	0.80
23.47	25.17	13.23	4.37	0	Yes	5.14	0.00	0.00
18	20.8	17.59	10.95	0.03	Yes	5.63	0.00	0.00
15.9	14.8	15.07	14.58	12.03	Yes	10.12	0.00	0.00
8.33	8.33	8.33	8.33	8.33	Yes	0.02	0.02	0.01
8.33	8.33	8.33	8.33	8.33	Yes	22.14	22.14	2.87
8.33	8.33	8.33	8.33	8.33	Yes	22.14	22.14	2.87
8.33	8.33	8.33	8.33	8.33	Yes	22.14	22.14	2.87
8.33	8.33	8.33	8.33	8.33	Yes	0.23	0.23	0.07

PM10	**PM2.5**	**SO2**
114.270	93.386	10.100

					Permit			
% Aug	**% Sep**	**% Oct**	**% Nov**	**% Dec**	**Status**	**PM10**	**PM2.5**	**SO2**
23.47	25.17	13.23	4.37	0	Yes	4.504541	4.504541	0.238638
18	20.8	17.59	10.95	0.03	Yes	7.2757	7.2757	0.393051
15.9	14.8	15.07	14.58	12.03	Yes	14.9476	14.9476	0.800139
23.47	25.17	13.23	4.37	0	Yes	5.136648	0	0
18	20.8	17.59	10.95	0.03	Yes	5.627177	0	0
15.9	14.8	15.07	14.58	12.03	Yes	10.11978	0	0
8.33	8.33	8.33	8.33	8.33	Yes	0.018027	0.018027	0.005615
8.33	8.33	8.33	8.33	8.33	Yes	22.13551	22.13551	2.865059
8.33	8.33	8.33	8.33	8.33	Yes	22.13551	22.13551	2.865059
8.33	8.33	8.33	8.33	8.33	Yes	22.13551	22.13551	2.865059
8.33	8.33	8.33	8.33	8.33	Yes	0.234006	0.234006	0.06738

PM10	**PM2.5**	**SO2**
114.270	93.386	10.100

					Permit			
% Aug	**% Sep**	**% Oct**	**% Nov**	**% Dec**	**Status**	**PM10**	**PM2.5**	**SO2**
23.47	25.17	13.23	4.37	0	Yes	4.504541	4.504541	0.238638
18	20.8	17.59	10.95	0.03	Yes	7.2757	7.2757	0.393051
15.9	14.8	15.07	14.58	12.03	Yes	14.9476	14.9476	0.800139
23.47	25.17	13.23	4.37	0	Yes	5.136648	0	0
18	20.8	17.59	10.95	0.03	Yes	5.627177	0	0
15.9	14.8	15.07	14.58	12.03	Yes	10.11978	0	0
8.33	8.33	8.33	8.33	8.33	Yes	0.018027	0.018027	0.005615
8.33	8.33	8.33	8.33	8.33	Yes	22.13551	22.13551	2.865059
8.33	8.33	8.33	8.33	8.33	Yes	22.13551	22.13551	2.865059
8.33	8.33	8.33	8.33	8.33	Yes	22.13551	22.13551	2.865059
8.33	8.33	8.33	8.33	8.33	Yes	0.234006	0.234006	0.06738

PM10	PM2.5	SO2
117.097	95.697	10.350

					Permit			
% Aug	% Sep	% Oct	% Nov	% Dec	Status	PM10	PM2.5	SO2
23.47	25.17	13.23	4.37	0	Yes	4.615993	4.615993	0.244542
18	20.8	17.59	10.95	0.03	Yes	7.455717	7.455717	0.402776
15.9	14.8	15.07	14.58	12.03	Yes	15.31744	15.31744	0.819936
23.47	25.17	13.23	4.37	0	Yes	5.263741	0	0
18	20.8	17.59	10.95	0.03	Yes	5.766406	0	0
15.9	14.8	15.07	14.58	12.03	Yes	10.37017	0	0
8.33	8.33	8.33	8.33	8.33	Yes	0.018473	0.018473	0.005754
8.33	8.33	8.33	8.33	8.33	Yes	22.68319	22.68319	2.935947
8.33	8.33	8.33	8.33	8.33	Yes	22.68319	22.68319	2.935947
8.33	8.33	8.33	8.33	8.33	Yes	22.68319	22.68319	2.935947
8.33	8.33	8.33	8.33	8.33	Yes	0.239796	0.239796	0.069047

PM10	PM2.5	SO2
119.991	98.062	10.606

					Permit			
% Aug	% Sep	% Oct	% Nov	% Dec	Status	PM10	PM2.5	SO2
23.47	25.17	13.23	4.37	0	Yes	4.730054	4.730054	0.250585
18	20.8	17.59	10.95	0.03	Yes	7.639947	7.639947	0.412728
15.9	14.8	15.07	14.58	12.03	Yes	15.69593	15.69593	0.840197
23.47	25.17	13.23	4.37	0	Yes	5.393807	0	0
18	20.8	17.59	10.95	0.03	Yes	5.908894	0	0
15.9	14.8	15.07	14.58	12.03	Yes	10.62641	0	0
8.33	8.33	8.33	8.33	8.33	Yes	0.01893	0.01893	0.005896
8.33	8.33	8.33	8.33	8.33	Yes	23.24369	23.24369	3.008494
8.33	8.33	8.33	8.33	8.33	Yes	23.24369	23.24369	3.008494
8.33	8.33	8.33	8.33	8.33	Yes	23.24369	23.24369	3.008494
8.33	8.33	8.33	8.33	8.33	Yes	0.245722	0.245722	0.070753

2011 Actual Emissions (tons/yr)						
NOx	VOC	CO	NH3	Benzene	Chlorine	HCl
71.117	4.600	57.833	8.500	0.010	0.000	0.000

2011 Actual Emissions							
NOx	VOC	CO	NH3	Benzene	Chlorine	HCl	
11.548	0.587	8.964	0.341	0.000			0.000
17.644	0.889	13.579	0.517	0.000			0.000
22.851	1.580	6.896	0.919	0.001			0.000
	0.000						0.854
	0.000						0.915
	0.000						1.516
0.052	0.004	0.011	0.000	0.000			0.000
6.100	0.534	10.161	2.390	0.003			0.000
6.666	0.452	8.697	2.031	0.003			0.000
5.851	0.512	9.412	2.301	0.003			0.000
0.405	0.042	0.113	0.000	0.000			0.000

2019 True-Up Emissions (tons/yr)						
NOx	VOC	CO	NH3	Benzene	Chlorine	HCl
716.100	13.865	177.279	28.369	0.030	0.000	0.000

clude Growth?	No

This is a pseudo-PTE validation. The turbines should

2019 True-Up Emissions							
NOx	VOC	CO	NH3	Benzene	Chlorine	HCl	
83.38	1.45	22.11	0.84	0.00	0.00	0.00	0.000
139.88	2.34	35.72	1.36	0.00	0.00	0.00	0.000
252.84	4.81	20.97	2.80	0.00	0.00	0.00	0.000
0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.137
0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.627
0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.120
0.17	0.01	0.01	0.00	0.00	0.00	0.00	0.000
79.19	1.74	32.77	7.79	0.01	0.00	0.00	0.000
79.19	1.74	32.77	7.79	0.01	0.00	0.00	0.000
79.19	1.74	32.77	7.79	0.01	0.00	0.00	0.000
2.26	0.06	0.16	0.00	0.00	0.00	0.00	0.000

2019 Projected Emissions (tons/yr)						
NOx	VOC	CO	NH3	Benzene	Chlorine	HCl
716.100	13.865	177.279	28.369	0.030	0.000	0.000

2019 Projected Emissions							
NOx	VOC	CO	NH3	Benzene	Chlorine	HCl	
83.38375	1.448	22.114	0.842	0.000057	0	0	0.000
139.8847	2.339	35.724	1.361	0.000084	0	0	0.000
252.8432	4.806	20.97	2.796	0.000235	0	0	0.000
0	0	0	0	0	0	0	5.137
0	0	0	0	0	0	0	5.627
0	0	0	0	0	0	0	10.120
0.17288	0.005	0.012	0	0.000102	0	0	0.000
79.18523	1.736	32.767	7.79	0.009917	0	0	0.000
79.18523	1.736	32.767	7.79	0.009917	0	0	0.000
79.18523	1.736	32.767	7.79	0.009917	0	0	0.000
2.259789	0.059	0.158	0	0	0	0	0.000

2024 Projected Emissions (tons/yr)						
NOx	VOC	CO	NH3	Benzene	Chlorine	HCl
716.100	13.865	177.279	28.369	0.030	0.000	0.000

2024 Projected Emissions							
NOx	VOC	CO	NH3	Benzene	Chlorine	HCl	
83.38375	1.448	22.114	0.842	0.000057	0	0	0.000
139.8847	2.339	35.724	1.361	0.000084	0	0	0.000
252.8432	4.806	20.97	2.796	0.000235	0	0	0.000
0	0	0	0	0	0	0	5.137
0	0	0	0	0	0	0	5.627
0	0	0	0	0	0	0	10.120
0.17288	0.005	0.012	0	0.000102	0	0	0.000
79.18523	1.736	32.767	7.79	0.009917	0	0	0.000
79.18523	1.736	32.767	7.79	0.009917	0	0	0.000
79.18523	1.736	32.767	7.79	0.009917	0	0	0.000
2.259789	0.059	0.158	0	0	0	0	0.000

2028 Projected Emissions (tons/yr)						
NOx	VOC	CO	NH3	Benzene	Chlorine	HCl
733.818	14.208	181.665	29.071	0.031	0.000	0.000

2028 Projected Emissions							
NOx	VOC	CO	NH3	Benzene	Chlorine	HCl	
85.44685	1.483827	22.66115	0.862833	5.841E-05	0	0	0.000
143.3457	2.396872	36.60789	1.394674	8.608E-05	0	0	0.000
259.0991	4.924911	21.48885	2.865179	0.0002408	0	0	0.000
0	0	0	0	0	0	0	5.264
0	0	0	0	0	0	0	5.766
0	0	0	0	0	0	0	10.370
0.177157	0.005124	0.012297	0	0.0001045	0	0	0.000
81.14445	1.778953	33.57773	7.982742	0.0101624	0	0	0.000
81.14445	1.778953	33.57773	7.982742	0.0101624	0	0	0.000
81.14445	1.778953	33.57773	7.982742	0.0101624	0	0	0.000
2.315701	0.06046	0.161909	0	0	0	0	0.000

2030 Projected Emissions (tons/yr)						
NOx	VOC	CO	NH3	Benzene	Chlorine	HCl
751.950	14.559	186.154	29.789	0.032	0.000	0.000

2030 Projected Emissions							
NOx	VOC	CO	NH3	Benzene	Chlorine	HCl	
87.55823	1.520492	23.2211	0.884153	5.985E-05	0	0	0.000
146.8878	2.456099	37.51247	1.429136	8.821E-05	0	0	0.000
265.5014	5.046605	22.01983	2.935978	0.0002468	0	0	0.000
0	0	0	0	0	0	0	5.394
0	0	0	0	0	0	0	5.909
0	0	0	0	0	0	0	10.626
0.181535	0.00525	0.012601	0	0.0001071	0	0	0.000
83.14952	1.82291	34.40743	8.179995	0.0104135	0	0	0.000
83.14952	1.82291	34.40743	8.179995	0.0104135	0	0	0.000
83.14952	1.82291	34.40743	8.179995	0.0104135	0	0	0.000
2.372922	0.061954	0.16591	0	0	0	0	0.000

be held flat with no growth, while the boilers should be grown - if possible.

Grow these normally if possible.

Hold these flat without growth

Old NOx = 81 tons/12 month per 3 turbines

State of Utah

JON M. HUNTSMAN, JR.
Governor

GARY HERBERT
Lieutenant Governor

Department of
Environmental Quality

William J. Sinclair
Acting Executive Director

DIVISION OF AIR QUALITY
Cheryl Heying
Director

DAQE-AN0103550015-09

January 12, 2009

Bill Lawson
PacifiCorp Energy
1407 W. North Temple
Suite 330
Salt Lake City, UT 84116

Dear Mr. Lawson:

Re: Approval Order: Minor Modification to Install an EFS Package on the Natural Gas Combustion Turbines at the Gadsby Power Plant
Salt Lake County; CDS A; MACT (Part 63), NSPS (Part 60), NSR, Nonattainment or Maintenance Area, Title IV (Part 72 / Acid Rain), Title V (Part 70)
Project Number: NSR0103550015

The attached document is the Approval Order for the above-referenced project. Future correspondence on this Approval Order should include the engineer's name as well as the DAQE number as shown on the upper right-hand corner of this letter. The project engineer for this action is John Jenks, who may be reached at (801) 536-4459.

Sincerely,

M. Cheryl Heying, Executive Secretary
Utah Air Quality Board

MCH:JJ:dn

cc: Salt Lake Valley Health Department

STATE OF UTAH

Department of Environmental Quality

Division of Air Quality

APPROVAL ORDER: Minor Modification to Install an EFS Package on the Natural Gas Combustion Turbines at the Gadsby Power Plant

Prepared By: John Jenks, Engineer
Phone: (801) 536-4459
Email: jjenks@utah.gov

APPROVAL ORDER NUMBER

DAQE-AN0103550015-09

Date: January 12, 2009

Gadsby Power Plant

Source Contact:
Mr. Jim Doak,
Phone: (801) 220-2306

M. Cheryl Heying
Executive Secretary
Utah Air Quality Board

Abstract

PacifiCorp Energy submitted an NOI to install the manufacturer's "Enhanced Flow and Speed" (or EFS) package on the natural gas combustion turbines located at the Gadsby Power Plant in Salt Lake City. The EFS package combines variable inlet guide vanes (VIGV) and software updates to improve airflow and engine speed. This will result in an increase in both efficiency and performance. Because of the increased efficiency, the only increase in emissions will be for CO. This increase is estimated to be 0.6 tons/year combined for all three turbines. No other changes are being sought at this time, although existing AOs DAQE-204-02 and DAQE-AN0355012-05 will be consolidated. All existing emission controls will remain.

This air quality AO authorizes the project with the following conditions and failure to comply with any of the conditions may constitute a violation of this order. This AO is issued to, and applies to the following:

Name of Permittee:

PacifiCorp Energy
1407 W. North Temple
Suite 330
Salt Lake City, UT 84116

Permitted Location:

Gadsby Power Plant
1407 West North Temple (rear)
Salt Lake City, UT 84116

UTM coordinates: 421,582 m Easting, 4,513,486 m Northing
SIC code: 4911 (Electric Services)

Section I: GENERAL PROVISIONS

I.1 All definitions, terms, abbreviations, and references used in this AO conform to those used in the UAC R307 and 40 CFR. Unless noted otherwise, references cited in these AO conditions refer to those rules. [R307-101]

I.2 The limits set forth in this AO shall not be exceeded without prior approval. [R307-401]

I.3 Modifications to the equipment or processes approved by this AO that could affect the emissions covered by this AO must be reviewed and approved. [R307-401-1]

I.4 All records referenced in this AO or in other applicable rules, which are required to be kept by the owner/operator, shall be made available to the Executive Secretary or Executive Secretary's representative upon request, and the records shall include the two-year period prior to the date of the request. Unless otherwise specified in this AO or in other applicable state and federal rules, records shall be kept for a minimum of five (5) years. [R307-401]. [R307-415-6b]

I.5 At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any equipment approved under this AO, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Executive Secretary which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. All maintenance performed on equipment authorized by this AO shall be recorded. [R307-401-4]

I.6 The owner/operator shall comply with R307-150 Series. Inventories, Testing and Monitoring. [R307-150]

I.7 The owner/operator shall comply with UAC R307-107. General Requirements: Unavoidable Breakdowns. [R307-107]

Section II: SPECIAL PROVISIONS

II.A The approved installations shall consist of the following equipment:

II.A.1 **Permitted Source**

II.A.2 **Boiler #1**
65 MW Gadsby 1 - Dual Fuel Boiler #1 with six Todd Combustion, Inc. Low-NO_x burners rated at 726 x 10^6 Btu/hr

II.A.3 **Boiler #2**
80 MW Gadsby 2 - Dual Fuel Boiler #2 with six Todd Combustion, Inc. Low-NO_x burners rated at 825 x 10^6 Btu/hr

II.A.4 **Boiler #3**
105 MW Gadsby 3 - Dual Fuel Boiler #3 rated at 1,155 x 10^6 Btu/hr

II.A.5 **Turbine #1**
GE LM6000 PC Sprint natural gas simple cycle turbine with: water injection, NO_x Selective Catalytic Reduction (SCR) catalyst and CO oxidation catalyst

II.A.6 **Turbine #2**
GE LM6000 PC Sprint natural gas simple cycle turbine with: water injection, NO_x Selective Catalytic Reduction (SCR) catalyst and CO oxidation catalyst

II.A.7 **Turbine #3**
GE LM6000 PC Sprint natural gas simple cycle turbine with: water injection, NO_x Selective Catalytic Reduction (SCR) catalyst and CO oxidation catalyst

II.A.8 **Emergency Black Start Generator**
Diesel-fired, rated at 1,350 bhp (1007 kW)

II.B Requirements and Limitations

II.B.1 **Conditions on Permitted Source**

II.B.1.a Visible emissions from the Gadsby boiler and turbine stacks shall not exceed 10% opacity. Opacity observations of emissions from stationary sources shall be conducted in accordance with 40 CFR 60, Appendix A, Method 9. [R307-401]

II.B.1.b In addition to the requirements of this AO, all applicable provisions of 40 CFR Part 72, 73, 75, 76, 77, and 78 - Federal regulations for the Acid Rain Program under Clean Air Act Title IV

apply to this installation. [40 CFR 75]

II.B.2 **Conditions on Black Start Generator**

II.B.2.a The emergency generator shall be used for electricity production only during the periods when electric power from the public utilities is interrupted, or for regular maintenance of the generator. Records documenting generator usage shall be kept in a log and they shall show the date the generator was used, the duration in hours of the generator usage, and the reason for each generator usage. [R307-401]

II.B.2.b The sulfur content of any fuel oil or diesel burned in the black start emergency generator engine shall not exceed 0.45 percent by weight.

The sulfur content shall be determined by ASTM Method D-4294-89 or approved equivalent. Certification of fuel oil shall be either by PacifiCorp's own testing or test reports from the used oil fuel marketer.. [R307-401]

II.B.2.c Visible emissions from the black start emergency generator exhaust shall not exceed 20% opacity; which shall be demonstrated by semiannual Method 9 visible emission observations.

Opacity observations of emissions from stationary sources shall be conducted according to 40 CFR 60, Appendix A, Method 9. [R307-401]

II.B.3 **Conditions on Natural Gas Combustion Turbines**

II.B.3.a Emissions to the atmosphere from the Turbine stacks shall not exceed the following rates and concentrations:

Pollutant	lb/hr* (15% O_2 dry)	ppmvd** (15% O_2 dry)	ppmvd*** (15% O_2 dry)
NO_x	22.2 (30-day rolling average)	5 (30-day rolling average)	116
CO	26.9 (8-hour block average)	10 (8-hour block average)	NA

* Total emissions for all three turbines under steady state operation not including startup and shutdown

** Emissions from an individual turbine under steady state operation not including startup and shutdown

***Emissions from an individual turbine, 40 CFR 60 Subpart GG requirement. [R307-401]

II.B.3.b Combined annual emissions from the three natural gas turbines shall not exceed the following amounts:

1. PM_{10} 29.5 tons per rolling 12-month period
2. NO_x 81.0 tons per rolling 12-month period
3. CO 98.30 tons per rolling 12-month period

4. SO_2 6.12 tons per rolling 12-month period

Compliance to the above annual emission limitations shall be determined as follows:

Turbine heat input (10^6 Btu/month) x emission factor (lb/10^6 Btu) x 1 ton/2000 lb = tons/month

Turbine heat input data shall be calculated using natural gas consumption readings from each turbine flow meter or CEMs data and natural gas caloric value provided by local distribution company.

Emission factors shall be as follows:

1. PM_{10} shall be obtained from EPA' s Compilation of Air Pollutant Emission Factors, AP-42 (Supplement F EPA, April 2000)
2. NO_x monthly average emission factor in lb/10^6 Btu shall be calculated from the ppmvd CEMs recorded data using 40 CFR 60App. A. Method 19
3. CO monthly average emission factor in lb/10^6 Btu shall be calculated from the ppmvd CEMs recorded data based on 40 CFR 60 App. A. Method 19
4. SO_2 emission factor shall be calculated with local distribution company natural gas sulfur content data and the EPA' s Compilation of Air Pollutant Emission Factors, AP-42 (Supplement F EPA, April 2000)

To determine compliance with a rolling 12-month total the owner/operator shall calculate a new 12-month total by the tenth day of each month using data from the previous 12 months. Records of emissions shall be kept for all periods when the plant is in operation. Fuel consumption shall be determined by a fuel meter provided for each turbine or from CEMs data. The records shall be kept on a continuous basis. [R307-401]

II.B.3.c The owner/operator shall install, calibrate, maintain, and operate a continuous monitoring system for measuring nitrogen oxides and carbon monoxide emissions discharged to the atmosphere from each turbine stack and record the output of the system. The monitoring system shall be used for measuring and determining compliance. The continuous monitoring system shall comply with applicable provisions of UAC, R307-170 and applicable Federal regulations for the Acid Rain Program under Clean Air Act Title IV.

The owner/operator shall maintain a CEMs monitoring plan. Such plan shall be made available to the Executive Secretary or the Executive's Secretary's representative upon request, or at any time the plan is changed. The plan shall address the number of monitors to be used, the method of measuring the rate in tons per hour, and the method of calculating emissions during the CEMs breakdowns. [R307-170]

II.B.3.d The owner/operator shall use only pipe line quality natural gas as fuel in the turbines. [R307-401]

II.B.4 **<u>Conditions on Boilers</u>**

II.B.4.a Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

1. Gadsby 1 boiler stack

Pollutant	Lbs/hr	ppmdv (3% O_2, dry)
NO_x	179.00	336

2. Gadsby 2 boiler stack

Pollutant	Lbs/hr	ppmdv (3% O_2, dry)
NO_x	204.00	336

3. Gadsby 3 boiler stack

a. Winter (November 1 through February 28):

Pollutant	Lbs/hr	ppmdv (3% O_2, dry)
NO_x	142.00	168

b. Summer (March 1 through October 31):

Pollutant	Lbs/hr	ppmdv (3% O_2, dry)
NO_x	203.00	168

. [R307-401]

II.B.4.b Monitoring to show compliance with the emission limitations stated in the above condition shall be performed as specified below:

Emission Point	Pollutant	Testing Status	Test Frequency
Gadsby 1 (Boiler Stack)	NO_x	*	**
Gadsby 2 (Boiler Stack)	NO_x	*	**
Gadsby 3 (Boiler Stack)	NO_x	*	**

Testing Status (To be applied above)

* Initial compliance testing was performed.

** Compliance shall be determined using a CEM as outlined below. [R307-150]

II.B.4.b.1 Compliance with the NO_x limits listed in II.B.4.a above shall be determined by calculating the arithmetic average of three contiguous one-hour period NO_x emission rates (lb/hr) or concentrations (ppmdv, 3% O_2 dry).

The owner/operator shall install, calibrate, maintain, and operate CEMs for NO_x and CO_2 as required by 40 CFR Part 75 for the Acid Rain Program. The hourly average O_2 concentration (percent by volume) shall be calculated from CO_2 concentration obtained from CO_2 CEMS in accordance with 40 CFR Part 75, Appendix F. The NO_x concentration (ppm) obtained from NO_x CEMS shall be corrected to 3% O_2 on hourly basis using the O_2 data calculated above. The emission rate (lb/hr) shall be calculated by multiplying the hourly average NO_x emission rate (lb/MMBtu) by the hourly heat input (MMBtu/hr). The hourly average NO_x emission rate (lb/MMBTU) shall be calculated by using NO_x and CO_2 concentrations obtained from CEMS in accordance with 40 CFR Part 75, Appendix F. The heat input shall be calculated by multiplying the measured fuel flow rate (scf/hr) by the hourly average CO_2 concentration (percent by volume) and by any necessary conversion factors in accordance with 40 CFR Part 75, Appendix F.

Each continuous emission monitoring system shall meet the Specifications and Test Procedures required by 40 CFR Part 75, Appendix A. The owner/operator shall implement Quality Assurance and Quality Control Procedures required by 40 CFR Part 75, Appendix B. [R307-150]

II.B.4.c PM_{10} emissions combined from the boilers covered in this AO (boiler #1, #2, and #3) shall not exceed 44.39 tons per rolling 12-month period.

Compliance to the above emission limitations shall be determined as follows:

The amount of the fuel used by equipment shall be recorded on daily basis. The amount of fuel used shall be multiplied by the following emission factors:

5.0 lb/10^6 ft3 for Boiler #1, #2, and #3 when natural gas fired
3.5 lb/10^3 gal for Boiler #1, #2, and #3 when #2 diesel fuel fired

The following equation shall be used to calculate combined one month emissions:

[(ft^3/month)* x 5.0 (lb/10^6 ft3) x (1 ton/2000 lbs)] + [(gal/month)** x 3.5 (lb/10^3 gal) x (1 ton/2000 lbs)] = tons/month emissions

* natural gas consumed by all boilers combined during one month
** #2 diesel fuel consumed by all boilers combined during one month

To determine compliance with a rolling 12-month total the owner/operator shall calculate a new 12-month total by the tenth day of each month using data from the previous 12 months. Records of emissions shall be kept for all periods when the plant is in operation. Fuel consumption shall be determined by examination of the fuel usage records. The consumption recording shall be maintained and kept on a daily basis. [R307-401]

II.B.4.d The owner/operator shall use only natural gas as a primary fuel and No. 2 fuel oil or better as back-up fuel in the boilers. The No. 2 fuel oil may be used only during periods of natural gas curtailment and for maintenance firings. Maintenance firings shall not exceed one-percent of the annual plant Btu requirement. In addition, maintenance firings shall be scheduled between

April 1 and November 30 of any calendar year. Records of fuel oil use shall be kept and they shall show the date the fuel oil was fired, the duration in hours the fuel oil was fired, the amount of fuel oil consumed during each curtailment, and the reason for each firing. Records shall be made available to the Executive Secretary or the Executive Secretary's representative upon request, and shall include a period of five years ending with the date of the request. [R307-401]

II.B.4.e The sulfur content of any fuel burned in the boilers shall not exceed 0.45% by weight as determined by ASTM Method D-4294-89 or approved equivalent. The sulfur content shall be tested if directed by the Executive Secretary. [R307-401]

Section III: APPLICABLE FEDERAL REQUIREMENTS

In addition to the requirements of this AO, all applicable provisions of the following federal programs have been found to apply to this installation. This AO in no way releases the owner or operator from any liability for compliance with all other applicable federal, state, and local regulations including UAC R307.

MACT (Part 63), ZZZZ: Recipro. Int. Comb Engine (RICE)
NSPS (Part 60), GG: Stationary Gas Turbines
Title IV (Part 72 / Acid Rain), (No subparts)

PERMIT HISTORY

This AO is based on the following documents:

Supersedes	DAQE-AN0355012-05 dated December 16, 2005
Supersedes	DAQE-204-02 dated April 3, 2002

ACRONYMS

The following lists commonly used acronyms and their associated translations as they apply to this document:

40 CFR	Title 40 of the Code of Federal Regulations
AO	Approval Order
ATT	Attainment Area
BACT	Best Available Control Technology
CAA	Clean Air Act
CAAA	Clean Air Act Amendments
CDS	Classification Data System (used by EPA to classify sources by size/type)
CEM	Continuous emissions monitor
CEMS	Continuous emissions monitoring system
CFR	Code of Federal Regulations
CO	Carbon monoxide
COM	Continuous opacity monitor
DAQ	Division of Air Quality (typically interchangeable with UDAQ)
DAQE	This is a document tracking code for internal UDAQ use
EPA	Environmental Protection Agency
HAP or HAPs	Hazardous air pollutant(s)
ITA	Intent to Approve
MACT	Maximum Achievable Control Technology
NAA	Nonattainment Area
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NOI	Notice of Intent
NO_x	Oxides of nitrogen
NSPS	New Source Performance Standard
NSR	New Source Review
PM_{10}	Particulate matter less than 10 microns in size
$PM_{2.5}$	Particulate matter less than 2.5 microns in size
PSD	Prevention of Significant Deterioration
R307	Rules Series 307
R307-401	Rules Series 307 - Section 401
SO_2	Sulfur dioxide
Title IV	Title IV of the Clean Air Act
Title V	Title V of the Clean Air Act
UAC	Utah Administrative Code
UDAQ	Utah Division of Air Quality (typically interchangeable with DAQ)
VOC	Volatile organic compounds

RACT EVALUATION REPORT
Gadsby Power Plant

1.0 INTRODUCTION AND FACILITY DESCRIPTION

1.1 Facility Identification

Name: Gadsby Power Plant
Address: 1407 West North Temple (rear), Salt Lake City, Utah,
Salt Lake County
Owner/Operator: PacifiCorp Energy
UTM coordinates: 4,513,486 m Northing, 421,582 m Easting, Zone 12

1.2 Facility Process Summary

The Gadsby Power Plant is a natural gas-fired electric generating plant consisting of three (3) steam boilers (Units #1, #2 and #3) and three (3) simple-cycle combustion turbines (Units #4, #5 and #6). Unit #1 is a 65 MW unit constructed in 1951, Unit #2 is an 80 MW unit constructed in 1952, and Unit #3 is a 105 MW unit constructed in 1955. Fuel oil may be used in Units #1, #2, and #3 as a back-up fuel during natural gas curtailments. Units #1 and #2 are equipped with low NOx burners. Units #4-6 are 43.5 MW LM6000 natural gas-fueled simple cycle combustion turbine engines that were added in 2002. The plant also has two small black start (emergency) generators (175 kW and 1,007 kW), three cooling towers for the boilers, and several small storage tanks. The plant is located in Salt Lake County, which is part of the Salt Lake City PM2.5 nonattainment area.

The plant is a Phase II acid rain source and a major source for both NOx and CO emissions. When the turbines were added in 2002, this expansion was permitted as a PSD major modification and a PM_{10} nonattainment area major modification for the NOx emissions, and ozone maintenance area major source (again for NOx emissions). Therefore, analysis of LAER was required for PM_{10}, NOx and VOC emissions; analysis of BACT was required for all other emissions from the turbines.

At the time of installation, BACT/LAER for the turbine addition was water injection, SCR and oxidation catalysts. These control systems and methodologies were required as part of the 2002 AO issuance.

1.3 Facility Criteria Air Pollutant Emissions Sources

The source consists of the following emission units:

65 MW natural gas-fired steam boiler (diesel fuel capable) – Unit #1
80 MW natural gas-fired steam boiler (diesel fuel capable) – Unit #2
105 MW natural gas-fired steam boiler (diesel fuel capable) – Unit #3
43.5 MW LM6000 natural gas-fueled simple cycle gas turbine – Unit #4

43.5 MW LM6000 natural gas-fueled simple cycle gas turbine – Unit #5
43.5 MW LM6000 natural gas-fueled simple cycle gas turbine – Unit #6
175 kW diesel generator – Em Gen #1
1,007 kW diesel generator – Em Gen #2
Storage tanks (several tanks ranging in size from 975 gallons to 4,200 gallons)
Cooling Towers #1, #2, #3

1.4 RACT Cut-off Threshold

A RACT cut-off threshold was established generally for all facilities based on Utah DAQ's existing small source exemption rule R307-401-9. This rule exempts sources of pollution with emissions less than 5 tpy from permitting requirements. Therefore, sources with baseline actual emissions which fall below this threshold could be exempted from evaluation under this general establishment.

At the PacifiCorp Gadsby facility, this cutoff threshold applies to the emergency generators, the storage tanks, and the cooling towers. Therefore, these emission units will not be evaluated for RACT.

2.0 RACT Evaluation

2.1 Natural Gas-fired Boilers

The three natural gas-fired boilers are primarily fired on pipeline quality natural gas; however, diesel fuel may be used during periods of natural gas curtailments and for maintenance firings. Maintenance firings may not exceed one percent (1%) of total annual heat input to the boilers.

The 2008 baseline emissions for the boilers were as follows:

$PM_{2.5}$ = 11.873
SO_2 = 1.02
NOx = 154.224
VOC = 8.593

$PM_{2.5}$

Available Control Technology

No additional add-on control technology has been identified by DAQ that can further reduce direct particulate emissions from natural gas combustion. All particulate generated from such combustion is considered to be PM 1. Typical add-on control devices – such as fabric filtration, electrostatic precipitation, or cyclonic separation – have extremely limited effectiveness in such an environment.

Since no additional available controls have been identified for the control of particulate emissions, the only remaining control is the default "no control" option of exclusive firing on pipeline quality natural gas.

Technically Infeasible RACT Controls

N/A – no additional controls identified.

Evaluation and Ranking of Technically Feasible RACT Controls

N/A – no additional controls identified.

Selection of RACT Controls

No additional control required. Combustion of such gas as fuel is recommended as RACT.

SO_2

Available Control Technology

Similarly, no additional add-on control technology has been identified by DAQ that can further reduce emissions of SO_2 from combustion of natural gas. Pipeline quality natural gas is inherently low in sulfur.

Technically Infeasible RACT Controls

N/A – no additional controls identified.

Evaluation and Ranking of Technically Feasible RACT Controls

N/A – no additional controls identified.

Selection of RACT Controls

No additional control required. Combustion of existing gas feedstock as fuel for control of SO_2 emissions is recommended as RACT.

VOC

Available Control Technology

Only one add-on control technology has been identified by DAQ to reduce emissions of VOC from natural gas-fired boilers – the use of oxidation catalysts. An oxidation catalyst is similar in design and operation to a catalytic control system on a passenger vehicle, in that an inline, self-regenerating, catalyst system is placed within the exhaust

stream prior to the final stack, so that emissions of CO and VOC can be further oxidized to CO_2 and water. Oxidation of VOC can approach efficiencies of 70%, depending on initial concentrations and stack characteristics.

Technically Infeasible RACT Controls

N/A – oxidation catalysts are technically feasible; therefore this section does not apply.

Evaluation and Ranking of Technically Feasible RACT Controls

As there is little to no supplemental energy or environmental costs associated with the installation or use of oxidation catalysts, the evaluation of this control technology versus the base case of no controls is one of economics. PacifiCorp analyzed the cost to install oxidation catalysts on each of the Gadsby facility boilers and for a variety of different options. The analysis was performed both with and without the installation of SCR; and for two different levels of control. The best control value obtained yielded 2.02 tons per year of VOCs reduced on boiler #3 assuming it was installed as part of a package with SCR. Even then, the oxidation catalyst alone was only able to achieve a relative control value of $171,100/ton of VOC. When installed separately, the cost for oxidation catalysts rises to $520,661/ton.

Selection of RACT Controls

The addition of oxidation catalysts to the three boilers at the Gadsby facility is not economically justified.

<u>NOx</u>

Available Control Technology

The following technologies have been identified as potential control methodologies for control of NOx emissions: good combustion practices (GCP – no additional controls, but proper operation of existing equipment); low emission combustion (LEC); selective non-catalytic reduction (SNCR); and selective catalytic reduction as potential NOx emission control technologies.

Technically Infeasible RACT Controls

Low emission combustion controls would require a redesign of the existing equipment. The boilers are fitted with low-NOx burners. Ultra-low-NOx burners would require a second conversion of the existing firebox which was already converted from coal to natural gas. The longer flame length associated with ULNB requires adjustment of firebox design and burner placement. This was deemed to be technically infeasible for this equipment.

Selective non-catalytic reduction is the simple injection of ammonia into the exhaust stream. This is technically feasible.

Selective catalytic reduction is the same, although with the addition of a catalyst bed to facilitate reduction at a lower exhaust stream temperature. This is also technically feasible.

Evaluation and Ranking of Technically Feasible RACT Controls

The remaining three control methodologies are then ranked in terms of control effectiveness.

1. SCR
2. SNCR
3. GCP

Both SCR and SNCR require ammonia injection, which generates ammonia slip – a source of particulate emissions. Direct particulate emissions are of greater impact on attainment demonstration than NOx emissions. Although the exact ratio is subject to debate depending on numerous factors; in general, the prevention of direct particulate emissions is good – especially for a relatively small reduction in NOx emissions.

Economic evaluation of SCR revealed that while SCR showed good potential NOx reductions (80 tpy at Unit 1, 90 tpy at Unit 2, 101 tpy at Unit 3) the control value was excessively high at nearly $180,000/ton NOx removed. Further analysis using actual emissions lowers the amount of emissions reduced (from 271 tpy total to 135 tpy total) and increases the cost to $361,333/ton.

The evaluation of SNCR was slightly better, showing a potential reduction of 53 tpy at a control cost of $45,000/ton. On an actual emission basis this would become 26.4 tpy with a cost of $91,000/ton.

Selection of RACT Controls

Based on the above evaluation, add-on SCR or SNCR controls are not economically or environmentally justified. The remaining control methodology, GCP is therefore recommended.

2.2 LM6000 Combustion Turbines

The three combustion turbines are each operated as a simple-cycle turbine fired exclusively on pipeline quality natural gas. Because each operates in simple cycle mode, there are no heat recovery steam generators and no associated duct firing emissions.

The 2008 baseline emissions were as follows:

$PM_{2.5}$ = 9.627 tons
SO_2 = 0.88 tons
NOx = 29.65 tons
VOC = 3.064 tons

<u>$PM_{2.5}$</u>

Available Control Technology

No additional add-on control technology has been identified by DAQ that can further reduce direct particulate emissions from natural gas combustion in a turbine generator. All particulate generated from natural gas combustion is considered to be PM 1. Typical add-on control devices – such as fabric filtration, electrostatic precipitation, or cyclonic separation – have extremely limited effectiveness in such an environment.

Since no additional available controls have been identified for the control of particulate emissions, the only remaining control is the default "no control" option of exclusive firing on pipeline quality natural gas.

Technically Infeasible RACT Controls

N/A – no additional controls identified.

Evaluation and Ranking of Technically Feasible RACT Controls

N/A – no additional controls identified.

Selection of RACT controls

No additional control required. Combustion of pipeline quality natural gas as fuel for control of particulate emissions is recommended as RACT.

<u>SO_2</u>

Available Control Technology

Similarly, no additional add-on control technology has been identified by DAQ that can further reduce emissions of SO_2 from combustion turbines. Pipeline quality natural gas is inherently low in sulfur. Total potential annual emissions from all three combustion turbines are less than 2 tpy of SO_2.

Most sulfur control technologies require the use of some sort of acid reducing agent such as lime slurry or limestone injection. This leads to residual solid or liquid waste which requires subsequent disposal. The remaining control techniques rely on reducing

emissions of particulates and allowing any residual sulfur to be captured with the particulate. With so little SO_2 (or particulate) being generated in the first place, further reductions of SO_2 using either active or passive control techniques are therefore next to impossible.

Technically Infeasible RACT Controls

N/A – no additional controls identified.

Evaluation and Ranking of Technically Feasible RACT Controls

N/A – no additional controls identified.

Selection of RACT Controls

No additional control required. Combustion of pipeline quality natural gas as fuel for control of SO_2 emissions is recommended as RACT.

<u>VOC</u>

Available Control Technology

Only one add-on control technology has been identified by DAQ to reduce emissions of VOC from combustion turbines – the use of oxidation catalysts. An oxidation catalyst is similar in design and operation to a catalytic control system on a passenger vehicle, in that an inline, self-regenerating, catalyst system is placed within the exhaust stream prior to the final stack, so that emissions of CO and VOC can be further oxidized to CO2 and water. Oxidation of VOC can approach efficiencies of 70%, depending on initial concentrations and stack characteristics.

All three turbines at the Gadsby facility have oxidation catalysts installed as these were required as CO BACT as part of the requirements of the 2002 AO to construct and operate the turbines.

Technically Infeasible RACT Controls

N/A – oxidation catalysts are technically feasible; therefore this section does not apply.

Evaluation and Ranking of Technically Feasible RACT Controls

The oxidation catalysts installed on the turbines bring the CO emission rate down to 10 ppm per turbine and 26.9 lbs/hr for all turbines combined (both limits on a 30 day average). While VOC emissions are not specifically limited, it is assumed that VOC emissions on a ppm basis are similar to CO emissions.

To determine if a greater level of control is possible, DAQ investigated the current level of VOC control available with oxidation catalysts in this turbine size range. New turbines can achieve as low as 2 ppm VOC emissions, but these are large mainline baseload units with much higher temperatures and specifically designed oxidation catalyst systems and greater inlet loading. For turbines in this size range, CO oxidation catalysts typically reduce CO emissions to the range of 10 ppm. VOC emissions roughly match CO emissions, but oxidation catalysts for a turbine of this size are designed for a CO emission rate rather than a VOC emission rate. Aiming for a lower CO emission rate of perhaps 5 ppm requires a higher stack temperature. This will require the burning of more fuel.

Increased heat requires that the turbines be operated more often, or requires that some supplemental heating is supplied to the oxidation catalyst to increase oxidation efficiency. Increased fuel burning to reduce VOC emissions is counter-productive. Attempting to reduce VOC emissions below 10 ppm is environmentally infeasible.

Selection of RACT controls

Retention of the existing oxidation catalyst systems for control of VOC emissions is recommended as RACT.

<u>NOx</u>

Available Control Technology

The following technologies have been identified as potential control methodologies for control of NOx emissions: good combustion practices (no additional controls, but proper operation of existing equipment); low emission combustion (LEC); selective non-catalytic reduction (SNCR); and selective catalytic reduction as potential NOx emission control technologies.

The LM6000 combustion turbine is an inherently low-NOx burner design. Water injection and water mist cooling of inlet air enable the turbine to achieve greater power output for a given fuel input by cooling flame temperature and densifying combustion air. This results in less thermal NOx generation and a higher mass flow against the turbine blades generating higher power output for the same amount of fuel.

Technically Infeasible RACT Controls

N/A – the turbines are LEC by design, Selective non-catalytic reduction is the simple injection of ammonia into the exhaust stream. This is technically feasible.

Selective catalytic reduction is the same, although with the addition of a catalyst bed to facilitate reduction at a lower exhaust stream temperature. This is also technically feasible.

Evaluation and Ranking of Technically Feasible RACT Controls

As the turbines are already LEC by design, the remaining two controls would ordinarily then be ranked by control effectiveness. However, the Gadsby facility turbines already have SCR systems installed. They were installed as LAER as part of the requirements for the 2002 AO to construct and operate. SCR systems have long been acknowledged as achieving the greatest degree of control of NOx on natural gas-fired turbine sources.

The NOx emissions from Gadsby are limited by the AO to 5 ppm for each turbine and 22.2 lbs/hr for all turbines combined (both limits on a 30 day average). While some newer SCR systems have been able to achieve NOx emission rates as low as 2 ppm on a 30 day average, these are found only in larger combined cycle turbines with much higher inlet loadings. For turbines in this size range, 5 ppm is appropriate.

However, PacifiCorp did investigate the option of extending the SCR catalyst beds on each of the three turbines and determined that a small amount of additional NOx control was possible at a minimum cost. Specifically, an additional 8 tons of NOx could be removed (on a potential-to-emit or PTE basis) from each turbine for $4,852/ton. This equates to 24 tons PTE or approximately 10.7 tons of actual emissions.

Selection of RACT Controls

Retention of the existing SCR systems along with extension of the catalyst beds for each of the combustion turbines to control NOx emissions is recommended as RACT.

3.0 Conclusion- Emissions Reduction through RACT implementation

The summary of all the above RACT evaluations is that PacifiCorp will extend the SCR catalyst beds on each of the three combustion turbines at the Gadsby facility. This will increase the amount of catalyst and slightly reduce NOx emissions.

Total NOx is expected to drop by 10.7 tons of actual emissions by the 2017 projection year.

4.0 Startup / Shutdown

The Gadsby plant's Units 1, 2 and 3 natural gas fired boilers have limits which apply at all times – whether the units are operating in steady-state mode or during periods of startup or shutdown. Therefore, no special consideration is required for these units during alternate operating periods.

On the other hand, the combustion turbines (Units 4, 5 and 6) have emission limits for NOx which apply during steady-state operation. These emission limits do not apply during periods of startup and shutdown because the catalyst in the SCR system requires a minimum operating temperature to effectively remove NOx.

In order to minimize emissions generated during startup and shutdown of the combustion turbines, PacifiCorp has defined an emission minimization plan. The plan is consists of two main components: defining the periods which constitute startup and shutdown, and limiting the total duration of those periods on a daily basis.

Although the turbines are simple cycle, and therefore similar in design to those used at other power generation facilities, PacifiCorp desired to specifically define both startup and shutdown in order to provide operational flexibility.

5.0 Implementation Schedule

The Unit 1, 2 and 3 boilers are already operating at RACT. No implementation schedule is required for these units.

It is the determination of this document that the catalyst beds on the Units 4, 5 and 6 SCR systems be extended. PacifiCorp has determined that this can most expeditiously be accomplished during the facility's next regularly scheduled maintenance outage, which will occur in April 2015. In order to allow for possible scheduling mishaps, delays and other unforeseen difficulties, the implementation date listed in IX.H.12.q.iv.D will be changed from January 1, 2017 to January 1, 2016. This provides PacifiCorp approximately eight (8) months to install and test the modified catalyst beds.

6.0 References

PacifiCorp Energy PM2.5 SIP Major Point Source RACT Documentation – Gadsby Power Plant
PacifiCorp Energy PM2.5 SIP Process, PacifiCorp Energy Gadsby and Lake Side Plants – dated April 30, 2014

RACT Evaluation Report –Gadsby Power Plant

UTAH $PM_{2.5}$ SIP RACT

Salt Lake City Nonattainment Area

Supporting Information