

Appendices

For

Regulatory Impact Analysis
For EPA's 2015 RCRA Final Rule
For Coal Combustion Residual (CCR)
Landfills & Surface Impoundments
at Electric Utility Plants

Note: EPA produced prior internal drafts of these Appendices based on data and other information from various sources, some of which have changed or become updated in 2014. To meet the court-ordered schedule for EPA's development and promulgation of the CCR final rule, EPA was unable to make conforming modifications and recalculations in all such cases throughout these Appendices. Text boxes indicate which appendices are affected by those modifications. See **Chapter 9** of this RIA for a description of the relevant modifications and the resultant recalculations.

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APPENDIX A

List of Operating Electric Utility Plants Potentially Affected by the CCR Rule (2012)

Note: EPA has updated the universe to reflect 61 actual and projected plant retirements occurring after 2012 according to the National Electric Energy Data System (NEEDS) v.5.13 dataset; see **Section 9.2.1** in **Chapter 9** for a description of the relevant updates. Exhibits in this appendix have not been updated to reflect the revisions described in **Section 9.2.1**.

Appendix A															
List of 478 Operating Electric Coal-Fired Utility Plants Potentially Affected by the CCR Rulemaking (2012)															
Count	Plant Code	Plant Name	Utility Code	Company Name	State	Sector Name	Nameplate Capacity (MW/hour)	Annual Tons Coal Burned	Annual Tons CCR Generated	Src[1]	L I G	B I T	W C	S U B	S C
1	3	Barry	195	Alabama Power Co	AL	Electric Utility	2,842	2,405,511	183,500		0	1	0	0	0
2	7	Gadsden	195	Alabama Power Co	AL	Electric Utility	138	27,059	3,900		0	1	0	0	0
3	8	Gorgas	195	Alabama Power Co	AL	Electric Utility	1,417	1,336,779	258,100		0	1	0	1	0
4	10	Greene County	195	Alabama Power Co	AL	Electric Utility	1,288	848,705	110,500		0	1	0	0	0
5	26	E C Gaston	195	Alabama Power Co	AL	Electric Utility	2,034	3,379,773	575,800		0	1	0	0	0
6	47	Colbert	18642	Tennessee Valley Authority	AL	Electric Utility	1,826	1,793,590	118,800		0	1	0	1	0
7	50	Widows Creek	18642	Tennessee Valley Authority	AL	Electric Utility	1,266	2,092,057	673,700		0	1	0	0	0
8	51	Dolet Hills	3265	Cleco Power LLC	LA	Electric Utility	721	3,896,462	1,185,100		1	0	0	0	0
9	56	Charles R Lowman	189	PowerSouth Energy Cooperative	AL	Electric Utility	538	852,044	145,200		0	1	0	0	0
10	59	Platte	40606	City of Grand Island - (NE)	NE	Electric Utility	110	302,952	17,100		0	0	0	1	0
11	60	Whelan Energy Center	8245	City of Hastings - (NE)	NE	Electric Utility	324	836,353	40,404	[2]	0	0	0	1	0
12	79	Aurora Energy LLC Chena	986	Aurora Energy LLC	AK	NAICS-22 Cogen	28	220,847	19,487	[2]	0	0	0	1	0
13	87	Escalante	30151	Tri-State G & T Assn, Inc	NM	Electric Utility	257	681,672	136,600		0	0	0	1	0
14	108	Holcomb	18315	Sunflower Electric Power Corp	KS	Electric Utility	349	1,178,237	67,200		0	0	0	1	0
15	113	Cholla	803	Arizona Public Service Co	AZ	Electric Utility	1,129	4,016,700	742,200		0	1	0	1	0
16	126	H Wilson Sundt Generating	24211	Tucson Electric Power Co	AZ	Electric Utility	558	44,049	5,000		0	1	0	1	0
17	127	Oklauion	15474	Public Service Co of Oklahoma	TX	Electric Utility	720	1,947,468	136,500		0	0	0	1	0
18	130	Cross	17543	South Carolina Public Service Authority	SC	Electric Utility	2,390	5,245,811	1,156,100		0	1	0	0	1
19	136	Seminole	21554	Seminole Electric Cooperative Inc	FL	Electric Utility	1,472	3,194,497	759,600		0	1	0	0	0
20	160	Apache Station	796	Arizona Electric Pwr Coop Inc	AZ	Electric Utility	661	763,302	119,200		0	0	0	1	0
21	165	GRDA	7490	Grand River Dam Authority	OK	Electric Utility	1,134	3,385,979	226,500		0	1	0	1	0
22	207	St Johns River Power Park	9617	JEA	FL	Electric Utility	1,358	2,905,917	440,000		0	1	0	0	1
23	298	Limestone	54888	NRG Texas Power LLC	TX	NAICS-22 Non-Cogen	1,850	7,920,204	1,160,300		1	0	0	1	0
24	384	Joliet 29	12384	Midwest Generations EME LLC	IL	NAICS-22 Non-Cogen	1,320	3,228,520	139,900		0	0	0	1	0
25	462	W N Clark	56146	Black Hills/Colorado Elec.Util	CO	Electric Utility	44	131,009	12,434	[2]	0	1	0	0	0
26	465	Arapahoe	15466	Public Service Co of Colorado	CO	Electric Utility	152	519,182	26,918	[2]	0	0	0	1	0
27	469	Cherokee	15466	Public Service Co of Colorado	CO	Electric Utility	551	1,428,860	247,100		0	1	0	1	0
28	470	Comanche	15466	Public Service Co of Colorado	CO	Electric Utility	1,635	5,281,706	374,300		0	0	0	1	0
29	477	Valmont	15466	Public Service Co of Colorado	CO	Electric Utility	251	429,050	43,900		0	1	0	1	0
30	492	Martin Drake	3989	City of Colorado Springs - (CO)	CO	Electric Utility	257	901,217	53,600		0	1	0	1	0
31	508	Lamar Plant	10633	City of Lamar - (CO)	CO	Electric Utility	6	0	1,393	[5,6]	0	0	0	1	0
32	525	Hayden	15466	Public Service Co of Colorado	CO	Electric Utility	439	1,179,177	103,600		0	1	0	1	0
33	527	Nucla	30151	Tri-State G & T Assn, Inc	CO	Electric Utility	114	355,785	169,100		0	1	0	0	0
34	564	Stanton Energy Center	14610	Orlando Utilities Comm	FL	Electric Utility	1,262	1,258,103	144,500		0	1	0	0	0
35	568	Bridgeport Station	15452	PSEG Power Connecticut LLC	CT	NAICS-22 Non-Cogen	582	76,020	700		0	0	0	1	0
36	594	Indian River Generating Station	9332	Indian River Operations Inc	DE	NAICS-22 Non-Cogen	641	656,044	208,100		0	1	0	1	0
37	602	Brandon Shores	58177	Raven Power Holdings LLC	MD	NAICS-22 Non-Cogen	1,370	2,121,680	340,500		0	1	0	0	0
38	628	Crystal River	6455	Duke Energy Florida, Inc	FL	Electric Utility	2,443	4,543,203	974,200		0	1	0	0	0
39	641	Crist	7801	Gulf Power Co	FL	Electric Utility	1,135	1,160,576	221,200		0	1	0	0	0
40	642	Scholz	7801	Gulf Power Co	FL	Electric Utility	98	3,771	336	[2]	0	1	0	0	0
41	643	Lansing Smith	7801	Gulf Power Co	FL	Electric Utility	1,002	395,203	40,000		0	1	0	0	0
42	645	Big Bend	18454	Tampa Electric Co	FL	Electric Utility	1,884	4,215,591	1,307,400		0	1	0	0	0
43	663	Deerhaven Generating Station	6909	Gainesville Regional Utilities	FL	Electric Utility	471	313,409	78,200		0	1	0	0	0
44	667	Northside Generating Station	9617	JEA	FL	Electric Utility	1,407	55,265	155,700		0	1	0	0	0
45	676	C D McIntosh Jr	10623	City of Lakeland - (FL)	FL	Electric Utility	994	578,725	126,400		0	1	0	0	0
46	703	Bowen	7140	Georgia Power Co	GA	Electric Utility	3,540	3,880,133	717,800		0	1	0	0	0
47	708	Hammond	7140	Georgia Power Co	GA	Electric Utility	953	650,448	189,900		0	1	0	0	0
48	709	Harlee Branch	7140	Georgia Power Co	GA	Electric Utility	1,746	879,190	86,200		0	1	0	0	0
49	710	Jack McDonough	7140	Georgia Power Co	GA	Electric Utility	2,604	18,093	3,400		0	1	0	0	0
50	727	Mitchell	7140	Georgia Power Co	GA	Electric Utility	247	1,545	100		0	1	0	0	0

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51	728	Yates	7140	Georgia Power Co	GA	Electric Utility	1,487	954,992	96,200		0	1	0	0	0
52	733	Kraft	7140	Georgia Power Co	GA	Electric Utility	352	45,690	6,100		0	1	0	0	0
53	753	Crisp Plant	4538	Crisp County Power Comm	GA	Electric Utility	18	28	3	[2]	0	1	0	0	0
54	856	E D Edwards	49756	Ameren Energy Resources Generating Co.	IL	Electric Utility	780	2,655,552	128,200		0	1	0	1	0
55	861	Coffeen	520	Ameren Energy Generating Co	IL	NAICS-22 Non-Cogen	1,005	3,170,655	213,300		0	1	0	1	0
56	867	Crawford	12384	Midwest Generations EME LLC	IL	NAICS-22 Non-Cogen	597	837,410	36,900		0	0	0	1	0
57	874	Joliet 9	12384	Midwest Generations EME LLC	IL	NAICS-22 Non-Cogen	360	676,030	53,400		0	0	0	1	0
58	876	Kincaid Generation LLC	5269	Equipower Resources Corp	IL	NAICS-22 Non-Cogen	1,319	3,244,292	171,600		0	0	0	1	0
59	879	Powerton	12384	Midwest Generations EME LLC	IL	NAICS-22 Non-Cogen	1,786	5,343,130	237,600		0	0	0	1	0
60	883	Waukegan	12384	Midwest Generations EME LLC	IL	NAICS-22 Non-Cogen	794	2,094,380	92,100		0	0	0	1	0
61	884	Will County	12384	Midwest Generations EME LLC	IL	NAICS-22 Non-Cogen	898	2,050,185	92,900		0	0	0	1	0
62	886	Fisk Street	12384	Midwest Generations EME LLC	IL	NAICS-22 Non-Cogen	663	558,130	27,700		0	0	0	1	0
63	887	Joppa Steam	5748	Electric Energy Inc	IL	NAICS-22 Non-Cogen	1,100	3,981,429	189,800		0	0	0	1	0
64	889	Baldwin Energy Complex	5517	Dynegy Midwest Generation Inc	IL	NAICS-22 Non-Cogen	1,894	7,130,025	347,300		0	0	0	1	0
65	891	Havana	5517	Dynegy Midwest Generation Inc	IL	NAICS-22 Non-Cogen	488	1,796,002	93,100		0	0	0	1	0
66	892	Hennepin Power Station	5517	Dynegy Midwest Generation Inc	IL	NAICS-22 Non-Cogen	306	1,289,450	74,800		0	0	0	1	0
67	898	Wood River	5517	Dynegy Midwest Generation Inc	IL	NAICS-22 Non-Cogen	500	1,603,742	78,000		0	0	0	1	0
68	963	Dallman	17828	City of Springfield - (IL)	IL	Electric Utility	668	1,095,644	280,000		0	1	0	0	0
69	976	Marion	17632	Southern Illinois Power Coop	IL	Electric Utility	422	1,077,332	116,400		0	1	1	0	0
70	981	State Line Energy	18041	State Line Energy LLC	IN	NAICS-22 Non-Cogen	614	343,860	16,621	[2]	0	0	0	1	0
71	983	Clifty Creek	9269	Indiana-Kentucky Electric Corp	IN	Electric Utility	1,304	3,261,514	192,700		0	1	0	1	0
72	988	Tanners Creek	9324	Indiana Michigan Power Co	IN	Electric Utility	1,100	1,480,175	101,300		0	1	0	1	0
73	990	Harding Street	9273	Indianapolis Power & Light Co	IN	Electric Utility	1,198	1,668,068	255,100		0	1	0	0	0
74	991	Eagle Valley	9273	Indianapolis Power & Light Co	IN	Electric Utility	396	174,088	10,900		0	1	0	0	0
75	992	CC Perry K	3599	Citizens Thermal Energy	IN	NAICS-22 Cogen	23	160,067	13,214	[2]	0	1	0	0	0
76	994	AES Petersburg	9273	Indianapolis Power & Light Co	IN	Electric Utility	2,155	4,555,791	1,040,700		0	1	0	0	0
77	995	Bailly	13756	Northern Indiana Pub Serv Co	IN	Electric Utility	641	888,439	258,600		0	1	0	0	0
78	997	Michigan City	13756	Northern Indiana Pub Serv Co	IN	Electric Utility	540	1,259,774	65,700		0	1	0	1	0
79	1001	Cayuga	15470	Duke Energy Indiana Inc	IN	Electric Utility	1,193	2,196,482	376,300		0	1	0	0	0
80	1004	Edwardsport	15470	Duke Energy Indiana Inc	IN	Electric Utility	144	0	33,488	[5,6]	0	0	0	0	0
81	1008	R Gallagher	15470	Duke Energy Indiana Inc	IN	Electric Utility	300	139,909	17,400		0	1	0	0	0
82	1010	Wabash River	15470	Duke Energy Indiana Inc	IN	Electric Utility	868	818,226	31,700		0	1	0	0	0
83	1012	F B Culley	17633	Southern Indiana Gas & Elec Co	IN	Electric Utility	369	794,347	203,700		0	1	0	0	0
84	1024	Crawfordsville	4508	Crawfordsville Elec, Lgt & Pwr	IN	Electric Utility	25	0	5,806	[5,6]	0	1	0	0	0
85	1032	Logansport	11142	City of Logansport - (IN)	IN	Electric Utility	61	94,432	7,871	[2]	0	1	0	0	0
86	1037	Peru	14839	City of Peru - (IN)	IN	Electric Utility	36	347	30	[2]	0	1	0	0	0
87	1040	Whitewater Valley	15989	City of Richmond - (IN)	IN	Electric Utility	94	15,048	1,479	[2]	0	1	0	0	0
88	1043	Frank E Ratts	9267	Hoosier Energy R E C, Inc	IN	Electric Utility	233	230,920	19,300		0	1	0	0	0
89	1046	Dubuque	9417	Interstate Power and Light Co	IA	Electric Utility	70	0	16,256	[5,6]	0	1	0	1	0
90	1047	Lansing	9417	Interstate Power and Light Co	IA	Electric Utility	314	780,898	68,900		0	1	0	1	0
91	1048	Milton L Kapp	9417	Interstate Power and Light Co	IA	Electric Utility	218	353,752	59,900		0	0	0	1	0
92	1073	Prairie Creek	9417	Interstate Power and Light Co	IA	Electric Utility	213	391,021	86,200		0	1	0	1	0
93	1077	Sutherland	9417	Interstate Power and Light Co	IA	Electric Utility	119	80,253	4,200		0	1	0	1	0
94	1081	Riverside	12341	MidAmerican Energy Co	IA	Electric Utility	141	444,488	24,100		0	0	0	1	0
95	1082	Walter Scott Jr Energy Center	12341	MidAmerican Energy Co	IA	Electric Utility	1,779	6,778,428	498,200		0	0	0	1	0
96	1091	George Neal North	12341	MidAmerican Energy Co	IA	Electric Utility	1,046	2,539,029	104,300		0	0	0	1	0
97	1104	Burlington	9417	Interstate Power and Light Co	IA	Electric Utility	291	776,818	100,800		0	0	0	1	0
98	1122	Ames Electric Services Power Plant	554	City of Ames - (IA)	IA	Electric Utility	109	212,760	9,605	[2]	0	0	0	1	0
99	1131	Streeter Station	3203	Cedar Falls Utilities	IA	Electric Utility	52	8,735	616	[2]	0	1	0	0	0

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Count	Plant Code	Plant Name	Utility Code	Company Name	State	Sector Name	Nameplate Capacity (MW/hour)	Annual Tons Coal Burned	Annual Tons CCR Generated	Src[1]	L I G	B I T	W C	S U B	S C
100	1167	Muscatine Plant #1	13143	Board of Water Electric & Communications	IA	Electric Utility	294	633,649	69,900		0	0	0	1	0
101	1175	Pella	14645	City of Pella - (IA)	IA	Electric Utility	38	21,133	1,221	[2]	0	0	0	1	0
102	1217	Earl F Wisdom	4363	Corn Belt Power Coop	IA	Electric Utility	143	2,959	389	[2]	0	1	0	1	0
103	1239	Riverton	5860	Empire District Electric Co	KS	Electric Utility	281	65,709	4,676	[2]	0	1	0	1	0
104	1241	La Cygne	10000	Kansas City Power & Light Co	KS	Electric Utility	1,578	5,116,878	340,000		0	1	0	1	0
105	1250	Lawrence Energy Center	22500	Westar Energy Inc	KS	Electric Utility	566	1,819,326	123,600		0	0	0	1	0
106	1252	Tecumseh Energy Center	22500	Westar Energy Inc	KS	Electric Utility	232	738,318	36,100		0	0	0	1	0
107	1295	Quindaro	9996	City of Kansas City - (KS)	KS	Electric Utility	388	555,098	41,200		0	0	0	1	0
108	1353	Big Sandy	22053	Kentucky Power Co	KY	Electric Utility	1,097	1,126,230	115,100		0	1	0	0	0
109	1355	E W Brown	10171	Kentucky Utilities Co	KY	Electric Utility	1,738	1,154,786	276,000		0	1	0	0	0
110	1356	Ghent	10171	Kentucky Utilities Co	KY	Electric Utility	2,226	5,824,285	1,403,600		0	1	0	0	0
111	1357	Green River	10171	Kentucky Utilities Co	KY	Electric Utility	189	469,853	38,500		0	1	0	0	0
112	1361	Tyrone	10171	Kentucky Utilities Co	KY	Electric Utility	75	0	17,418	[5,6]	0	1	0	0	0
113	1363	Cane Run	11249	Louisville Gas & Electric Co	KY	Electric Utility	661	1,315,046	139,700		0	1	0	0	0
114	1364	Mill Creek	11249	Louisville Gas & Electric Co	KY	Electric Utility	1,717	3,879,218	1,187,600		0	1	0	1	0
115	1374	Elmer Smith	14268	City of Owensboro - (KY)	KY	Electric Utility	445	1,223,751	401,400		0	1	0	0	0
116	1378	Paradise	18642	Tennessee Valley Authority	KY	Electric Utility	2,558	6,398,036	1,595,900		0	1	0	0	0
117	1379	Shawnee	18642	Tennessee Valley Authority	KY	Electric Utility	1,575	3,699,420	248,300		0	1	0	1	0
118	1381	Kenneth C Coleman	1692	Big Rivers Electric Corp	KY	Electric Utility	602	1,495,155	377,100		0	1	0	0	0
119	1382	HMP&L Station Two Henderson	1692	Big Rivers Electric Corp	KY	Electric Utility	405	845,974	244,200		0	1	0	0	0
120	1383	Robert A Reid	1692	Big Rivers Electric Corp	KY	Electric Utility	195	14,301	1,189	[2]	0	1	0	0	0
121	1384	Cooper	5580	East Kentucky Power Coop, Inc	KY	Electric Utility	344	630,140	117,100		0	1	0	0	0
122	1385	Dale	5580	East Kentucky Power Coop, Inc	KY	Electric Utility	216	118,238	12,000		0	1	0	0	0
123	1393	R S Nelson	55936	Entergy Gulf States - LA LLC	LA	Electric Utility	1,597	2,062,674	494,600		0	0	0	1	0
124	1552	C P Crane	58177	Raven Power Holdings LLC	MD	NAICS-22 Non-Cogen	416	459,822	24,600		0	1	0	1	0
125	1554	Herbert A Wagner	58177	Raven Power Holdings LLC	MD	NAICS-22 Non-Cogen	1,058	498,035	59,800		0	1	0	1	0
126	1570	FirstEnergy R Paul Smith Power Station	23279	Allegheny Energy Supply Co LLC	MD	NAICS-22 Non-Cogen	110	44,065	6,600		0	1	0	0	0
127	1571	Chalk Point LLC	12628	NRG Chalk Point LLC	MD	NAICS-22 Non-Cogen	2,647	700,414	207,900		0	1	0	0	0
128	1572	Dickerson	12653	GenOn Mid-Atlantic LLC	MD	NAICS-22 Non-Cogen	930	467,051	164,100		0	1	0	0	0
129	1573	Morgantown Generating Plant	12653	GenOn Mid-Atlantic LLC	MD	NAICS-22 Non-Cogen	1,548	1,972,856	519,200		0	1	0	0	0
130	1606	Mount Tom	58185	FirstLight Power Resources, Inc. - MA	MA	NAICS-22 Non-Cogen	136	52,226	7,500		0	1	0	0	0
131	1619	Brayton Point	58534	Brayton Point Energy LLC	MA	NAICS-22 Non-Cogen	1,611	780,208	92,000		0	1	0	0	0
132	1626	Salem Harbor	57501	NAES Salem Harbor	MA	NAICS-22 Non-Cogen	641	121,369	9,300		0	1	0	0	0
133	1695	B C Cobb	4254	Consumers Energy Co	MI	Electric Utility	313	858,909	56,100		0	1	0	1	0
134	1702	Dan E Karn	4254	Consumers Energy Co	MI	Electric Utility	1,946	1,243,913	67,300		0	1	0	1	0
135	1710	J H Campbell	4254	Consumers Energy Co	MI	Electric Utility	1,604	4,392,601	216,200		0	1	0	1	0
136	1720	J C Weadock	4254	Consumers Energy Co	MI	Electric Utility	313	865,904	55,200		0	1	0	1	0
137	1723	J R Whiting	4254	Consumers Energy Co	MI	Electric Utility	345	813,471	53,900		0	1	0	1	0
138	1731	Harbor Beach	5109	The DTE Electric Company	MI	Electric Utility	125	43,846	8,600		0	1	0	1	0
139	1733	Monroe	5109	The DTE Electric Company	MI	Electric Utility	3,293	7,933,510	635,000		0	1	0	1	0
140	1740	River Rouge	5109	The DTE Electric Company	MI	Electric Utility	944	1,227,335	68,000		0	1	0	1	0
141	1743	St Clair	5109	The DTE Electric Company	MI	Electric Utility	1,571	3,208,739	152,800		0	1	0	1	0
142	1745	Trenton Channel	5109	The DTE Electric Company	MI	Electric Utility	776	1,914,758	112,000		0	1	0	1	0
143	1769	Presque Isle	20847	Wisconsin Electric Power Co	MI	Electric Utility	450	1,257,495	52,200		0	1	1	1	0
144	1771	Escanaba	58246	Escanaba Operating Services LLC	MI	Electric Utility	41	10,441	1,149	[2]	0	1	0	0	0
145	1825	J B Sims	7483	City of Grand Haven	MI	Electric Utility	80	137,243	12,462	[2]	0	1	0	0	0
146	1830	James De Young	8723	City of Holland	MI	Electric Utility	63	37,341	2,356	[2]	0	1	0	1	0

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147	1831	Eckert Station	56155	Lansing Board of Water and Light	MI	Electric Utility	375	635,430	60,000		0	0	0	1	0
148	1832	Erickson Station	56155	Lansing Board of Water and Light	MI	Electric Utility	155	402,156	28,100		0	0	0	1	0
149	1843	Shiras	11701	City of Marquette - (MI)	MI	Electric Utility	65	195,672	8,429	[2]	0	1	0	1	0
150	1866	Wyandotte	21048	Wyandotte Municipal Serv Comm	MI	Electric Utility	78	42,083	2,184	[2]	0	1	0	1	0
151	1891	Syl Laskin	12647	Minnesota Power Inc	MN	Electric Utility	116	280,203	12,600		0	1	0	1	0
152	1893	Clay Boswell	12647	Minnesota Power Inc	MN	Electric Utility	1,073	4,224,848	219,000		0	0	0	1	0
153	1897	M L Hibbard	12647	Minnesota Power Inc	MN	Electric Utility	73	0	16,953	[5,6]	0	0	0	1	0
154	1904	Black Dog	13781	Northern States Power Co - Minnesota	MN	Electric Utility	602	779,334	35,000		0	0	0	1	0
155	1915	Allen S King	13781	Northern States Power Co - Minnesota	MN	Electric Utility	598	1,849,798	141,900		0	0	0	1	0
156	1943	Hoot Lake	14232	Otter Tail Power Co	MN	Electric Utility	131	408,586	16,000		0	0	0	1	0
157	1961	Austin Northeast	1009	City of Austin - (MN)	MN	Electric Utility	32	100	6	[2]	0	1	0	0	0
158	1979	Hibbing	8543	Hibbing Public Utilities Comm	MN	Electric Utility	36	85,867	4,254	[2]	0	0	0	1	0
159	2008	Silver Lake	16181	Rochester Public Utilities	MN	Electric Utility	99	25,598	2,240	[2]	0	1	0	1	0
160	2018	Virginia	19883	City of Virginia	MN	Electric Utility	26	42,736	2,095	[2]	0	0	0	1	0
161	2022	Willmar	20737	Willmar Municipal Utilities	MN	Electric Utility	30	34,867	3,368	[2]	0	0	0	1	0
162	2049	Jack Watson	12686	Mississippi Power Co	MS	Electric Utility	1,216	761,034	69,900		0	1	0	0	0
163	2062	Henderson	7651	Greenwood Utilities Comm	MS	Electric Utility	46	0	10,683	[5,6]	0	1	0	0	0
164	2076	Asbury	5860	Empire District Electric Co	MO	Electric Utility	232	731,755	41,400		0	1	0	1	0
165	2079	Hawthorn	10000	Kansas City Power & Light Co	MO	Electric Utility	1,070	2,218,267	121,300		0	0	0	1	0
166	2080	Montrose	10000	Kansas City Power & Light Co	MO	Electric Utility	564	1,124,150	57,900		0	0	0	1	0
167	2094	Sibley	56211	KCP&L Greater Missouri Operations Co	MO	Electric Utility	524	1,288,401	79,700		0	1	0	1	0
168	2098	Lake Road	56211	KCP&L Greater Missouri Operations Co	MO	Electric Utility	273	328,933	20,400		0	1	0	1	0
169	2103	Labadie	19436	Union Electric Co - (MO)	MO	Electric Utility	2,389	8,895,142	448,400		0	0	0	1	0
170	2104	Meramec	19436	Union Electric Co - (MO)	MO	Electric Utility	1,041	2,654,100	122,100		0	0	0	1	0
171	2107	Sioux	19436	Union Electric Co - (MO)	MO	Electric Utility	1,099	2,738,921	268,000		0	1	0	1	0
172	2123	Columbia	4045	City of Columbia - (MO)	MO	Electric Utility	101	20,829	1,654	[2]	0	1	0	0	0
173	2132	Blue Valley	9231	City of Independence - (MO)	MO	Electric Utility	115	84,451	25,600		0	1	0	0	0
174	2144	Marshall	11732	City of Marshall - (MO)	MO	Electric Utility	57	88	8	[2]	0	1	0	0	0
175	2161	James River Power Station	17833	City Utilities of Springfield - (MO)	MO	Electric Utility	450	356,855	19,400		0	0	0	1	0
176	2167	New Madrid	924	Associated Electric Coop, Inc	MO	Electric Utility	1,300	4,422,135	211,000		0	0	0	1	0
177	2168	Thomas Hill	924	Associated Electric Coop, Inc	MO	Electric Utility	1,182	4,143,198	624,600		0	0	0	1	0
178	2169	Chamois	3242	Central Electric Power Coop - (MO)	MO	Electric Utility	59	196,501	9,688	[2]	0	1	0	1	0
179	2171	Missouri City	9231	City of Independence - (MO)	MO	Electric Utility	46	12,543	1,096	[2]	0	1	0	0	0
180	2187	J E Corette Plant	15298	PPL Montana LLC	MT	NAICS-22 Non-Cogen	173	469,064	19,900		0	0	0	1	0
181	2240	Lon Wright	6779	City of Fremont - (NE)	NE	Electric Utility	170	302,402	15,500		0	0	0	1	0
182	2277	Sheldon	13337	Nebraska Public Power District	NE	Electric Utility	229	694,334	25,300		0	0	0	1	0
183	2291	North Omaha	14127	Omaha Public Power District	NE	Electric Utility	645	1,967,299	98,700		0	0	0	1	0
184	2324	Reid Gardner	13407	Nevada Power Co	NV	Electric Utility	637	730,149	78,700		0	1	0	1	0
185	2364	Merrimack	15472	Public Service Co of NH	NH	Electric Utility	496	468,909	44,600		0	1	0	0	0
186	2367	Schiller	15472	Public Service Co of NH	NH	Electric Utility	171	50,775	15,400		0	1	0	0	0
187	2378	B L England	55768	RC Cape May Holdings LLC	NJ	NAICS-22 Non-Cogen	484	79,194	11,200		0	1	0	1	0
188	2403	PSEG Hudson Generating Station	15147	PSEG Fossil LLC	NJ	NAICS-22 Non-Cogen	660	107,936	22,600		0	1	0	1	0

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189	2408	PSEG Mercer Generating Station	15147	PSEG Fossil LLC	NJ	NAICS-22 Non-Cogen	768	120,418	19,700		0	1	0	0
190	2434	Howard Down	19856	City of Vineland - (NJ)	NJ	Electric Utility	68	0	15,792	[5,6]	0	1	0	0
191	2442	Four Corners	803	Arizona Public Service Co	NM	Electric Utility	2,270	8,030,690	2,077,200		0	1	0	1
192	2451	San Juan	15473	Public Service Co of NM	NM	Electric Utility	1,848	5,740,086	1,563,200		0	1	0	0
193	2468	Raton	15698	Raton Public Service Company	NM	Electric Utility	8	0	1,858	[5,6]	0	1	0	0
194	2527	GMMGreenidge LLC	25	GMM Holdings 1 LLC	NY	NAICS-22 Non-Cogen	112	0	26,010	[5,6]	0	1	0	0
195	2535	Cayuga Operating Company	22125	Cayuga Operating Company, LLC	NY	NAICS-22 Non-Cogen	322	228,202	64,700		0	1	0	1
196	2549	C R Huntley Generating Station	13168	NRG Huntley Operations Inc	NY	NAICS-22 Non-Cogen	400	448,405	23,100		0	0	0	1
197	2554	Dunkirk Generating Plant	13579	Dunkirk Power LLC	NY	NAICS-22 Non-Cogen	192	395,243	20,800		0	1	0	1
198	2682	S A Carlson	9645	Jamestown Board of Public Util	NY	Electric Utility	96	5,522	665	[2]	0	1	0	0
199	2706	Asheville	3046	Progress Energy Carolinas Inc	NC	Electric Utility	837	815,705	731,200		0	1	0	0
200	2708	Cape Fear	3046	Progress Energy Carolinas Inc	NC	Electric Utility	84	229,383	12,600		0	1	0	0
201	2709	HF Lee Plant	3046	Progress Energy Carolinas Inc	NC	Electric Utility	508	359,468	40,300		0	1	0	0
202	2712	Roxboro	3046	Progress Energy Carolinas Inc	NC	Electric Utility	2,558	5,968,312	1,454,800		0	1	0	0
203	2713	L V Sutton Steam	3046	Progress Energy Carolinas Inc	NC	Electric Utility	763	603,818	51,900		0	1	0	0
204	2718	G G Allen	5416	Duke Energy Carolinas, LLC	NC	Electric Utility	1,155	877,331	169,500		0	1	0	0
205	2720	Buck	5416	Duke Energy Carolinas, LLC	NC	Electric Utility	941	98,628	10,100		0	1	0	0
206	2721	Cliffside	5416	Duke Energy Carolinas, LLC	NC	Electric Utility	1,480	479,670	259,900		0	1	0	0
207	2727	Marshall	5416	Duke Energy Carolinas, LLC	NC	Electric Utility	1,996	3,701,270	797,000		0	1	0	0
208	2732	Riverbend	5416	Duke Energy Carolinas, LLC	NC	Electric Utility	466	79,371	8,100		0	1	0	0
209	2790	R M Heskett	12199	Montana-Dakota Utilities Co	ND	Electric Utility	115	447,177	33,800		1	0	0	1
210	2817	Leland Olds	1307	Basin Electric Power Coop	ND	Electric Utility	656	2,839,782	292,800		1	0	0	1
211	2823	Milton R Young	12658	Minnkota Power Coop, Inc	ND	Electric Utility	734	4,357,753	516,600		1	0	0	0
212	2824	Stanton	7570	Great River Energy	ND	Electric Utility	191	707,778	43,300		0	0	0	1
213	2828	Cardinal	3006	Cardinal Operating Co	OH	Electric Utility	1,880	2,966,099	800,100		0	1	0	1
214	2830	Walter C Beckjord	3542	Duke Energy Ohio Inc	OH	Electric Utility	1,318	1,450,245	139,000		0	1	0	0
215	2832	Miami Fort	3542	Duke Energy Ohio Inc	OH	Electric Utility	1,344	3,595,575	502,100		0	1	0	0
216	2835	FirstEnergy Ashtabula	6526	FirstEnergy Generation Corp	OH	NAICS-22 Non-Cogen	256	138,997	10,800		0	1	0	1
217	2836	Avon Lake	14165	NRG Power Midwest LP	OH	NAICS-22 Non-Cogen	795	1,020,656	82,000		0	1	0	0
218	2837	FirstEnergy Eastlake	6526	FirstEnergy Generation Corp	OH	NAICS-22 Non-Cogen	401	1,958,966	132,500		0	1	0	1
219	2838	FirstEnergy Lake Shore	6526	FirstEnergy Generation Corp	OH	NAICS-22 Non-Cogen	260	130,054	7,400		0	1	0	1
220	2840	Conesville	14006	Ohio Power Co	OH	Electric Utility	1,891	2,708,429	1,071,700		0	1	0	0
221	2843	Picway	14006	Ohio Power Co	OH	Electric Utility	106	2,381	300		0	1	0	0
222	2848	O H Hutchings	4922	Dayton Power & Light Co	OH	Electric Utility	447	27,464	2,800		0	1	0	0
223	2850	J M Stuart	4922	Dayton Power & Light Co	OH	Electric Utility	2,452	5,007,218	1,639,100		0	1	0	0
224	2861	Niles	14165	NRG Power Midwest LP	OH	NAICS-22 Non-Cogen	27	25,130	14,000		0	1	0	0
225	2866	FirstEnergy W H Sammis	6526	FirstEnergy Generation Corp	OH	NAICS-22 Non-Cogen	2,468	4,123,231	338,700		0	1	0	1
226	2872	Muskingum River	14006	Ohio Power Co	OH	Electric Utility	1,529	782,974	105,700		0	1	0	1
227	2876	Kyger Creek	14015	Ohio Valley Electric Corp	OH	Electric Utility	1,086	1,932,494	528,400		0	1	0	1
228	2878	FirstEnergy Bay Shore	6526	FirstEnergy Generation Corp	OH	NAICS-22 Non-Cogen	655	247,550	209,900		0	1	0	1
229	2914	Dover	5336	City of Dover - (OH)	OH	Electric Utility	50	38,043	3,304	[2]	0	1	0	0
230	2917	Hamilton	7977	City of Hamilton - (OH)	OH	Electric Utility	127	61,179	9,600		0	1	0	0
231	2935	Orrville	14194	City of Orrville - (OH)	OH	Electric Utility	72	124,831	12,022	[2]	0	1	0	0
232	2936	Painesville	14381	City of Painesville	OH	Electric Utility	56	16,945	1,371	[2]	0	1	0	0
233	2943	Shelby Municipal Light Plant	17043	City of Shelby - (OH)	OH	Electric Utility	10	0	2,322	[5,6]	0	1	0	0
234	2952	Muskogee	14063	Oklahoma Gas & Electric Co	OK	Electric Utility	1,716	4,936,483	202,500		0	0	0	1
235	2963	Northeastern	15474	Public Service Co of Oklahoma	OK	Electric Utility	1,950	3,572,825	251,100		0	1	0	1
236	3098	Elrama Power Plant	14165	NRG Power Midwest LP	PA	NAICS-22 Non-Cogen	510	43,910	10,600		0	1	0	0
237	3113	Portland	17235	NRG REMA LLC	PA	NAICS-22 Non-Cogen	621	68,549	5,400		0	1	0	0
238	3115	Titus	17235	NRG REMA LLC	PA	NAICS-22 Non-Cogen	261	46,003	7,300		0	1	0	0

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239	3118	Conemaugh	15873	GenOn Northeast Management Company	PA	NAICS-22 Non-Cogen	1,884	4,188,822	1,054,000		0	1	0	0	1
240	3122	Homer City Station	12384	Midwest Generations EME LLC	PA	NAICS-22 Non-Cogen	2,012	4,065,631	715,900		0	1	0	0	0
241	3130	Seward	54885	NRG Wholesale Generation LP	PA	NAICS-22 Non-Cogen	585	1,727,531	1,651,700		0	0	1	0	0
242	3131	Shawville	17235	NRG REMA LLC	PA	NAICS-22 Non-Cogen	632	628,939	93,100		0	1	0	0	0
243	3136	Keystone	15873	GenOn Northeast Management Company	PA	NAICS-22 Non-Cogen	1,884	3,645,459	881,100		0	1	0	0	1
244	3138	New Castle Plant	14165	NRG Power Midwest LP	PA	NAICS-22 Non-Cogen	351	179,683	32,000		0	1	0	0	0
245	3140	PPL Brunner Island	15537	PPL Brunner Island LLC	PA	NAICS-22 Non-Cogen	1,567	2,381,317	591,700		0	1	0	0	0
246	3149	PPL Montour	15534	PPL Montour LLC	PA	NAICS-22 Non-Cogen	1,642	3,096,776	806,700		0	1	0	0	0
247	3152	Sunbury Generation LP	22001	Sunbury Generation LP	PA	NAICS-22 Non-Cogen	491	102,784	27,300		0	1	0	0	0
248	3178	FirstEnergy Armstrong Power Station	23279	Allegheny Energy Supply Co LLC	PA	NAICS-22 Non-Cogen	326	157,722	14,500		0	1	0	0	0
249	3179	Hatfields Ferry Power Station	23279	Allegheny Energy Supply Co LLC	PA	NAICS-22 Non-Cogen	1,728	3,936,487	1,101,300		0	1	0	1	0
250	3181	FirstEnergy Mitchell Power Station	23279	Allegheny Energy Supply Co LLC	PA	NAICS-22 Non-Cogen	374	525,333	174,500		0	1	0	0	0
251	3251	H B Robinson	3046	Progress Energy Carolinas Inc	SC	Electric Utility	16	98,417	11,300		0	1	0	0	0
252	3264	W S Lee	5416	Duke Energy Carolinas, LLC	SC	Electric Utility	463	61,892	6,000		0	1	0	0	0
253	3280	Canadys Steam	17539	South Carolina Electric&Gas Co	SC	Electric Utility	490	685,415	80,900		0	1	0	0	0
254	3287	McMeekin	17539	South Carolina Electric&Gas Co	SC	Electric Utility	294	220,190	20,800		0	1	0	0	0
255	3295	Urquhart	17539	South Carolina Electric&Gas Co	SC	Electric Utility	759	86,078	10,400		0	1	0	0	0
256	3297	Wateree	17539	South Carolina Electric&Gas Co	SC	Electric Utility	772	1,518,072	249,200		0	1	0	0	0
257	3298	Williams	17554	South Carolina Genertg Co, Inc	SC	Electric Utility	686	1,440,510	218,200		0	1	0	0	0
258	3319	Jefferies	17543	South Carolina Public Service	SC	Electric Utility	578	139,344	26,500		0	1	0	0	0
259	3325	Ben French	19545	Black Hills Power Inc	SD	Electric Utility	135	82,050	4,407	[2]	0	0	0	1	0
260	3393	Allen Steam Plant	18642	Tennessee Valley Authority	TN	Electric Utility	1,611	2,441,584	133,200		0	1	0	1	0
261	3396	Bull Run	18642	Tennessee Valley Authority	TN	Electric Utility	950	758,216	101,000		0	1	0	0	0
262	3399	Cumberland	18642	Tennessee Valley Authority	TN	Electric Utility	2,600	6,128,108	1,312,800		0	1	0	1	0
263	3403	Gallatin	18642	Tennessee Valley Authority	TN	Electric Utility	1,918	3,847,653	202,500		0	1	0	1	0
264	3405	John Sevier	18642	Tennessee Valley Authority	TN	Electric Utility	1,797	261,930	26,000		0	1	0	0	0
265	3406	Johnsonville	18642	Tennessee Valley Authority	TN	Electric Utility	2,911	1,822,395	124,000		0	1	0	1	0
266	3407	Kingston	18642	Tennessee Valley Authority	TN	Electric Utility	1,700	2,206,290	311,400		0	1	0	1	0
267	3470	W A Parish	54888	NRG Texas Power LLC	TX	NAICS-22 Non-Cogen	4,008	8,845,229	476,000		0	0	0	1	0
268	3497	Big Brown	56884	Big Brown Power Company LLC	TX	NAICS-22 Non-Cogen	1,187	5,514,280	597,500		1	0	0	1	0
269	3644	Carbon	14354	PacifiCorp	UT	Electric Utility	189	605,826	68,600		0	1	0	0	0
270	3775	Clinch River	733	Appalachian Power Co	VA	Electric Utility	712	384,068	45,400		0	1	0	0	0
271	3776	Glen Lyn	733	Appalachian Power Co	VA	Electric Utility	338	36,934	3,400		0	1	0	0	0
272	3788	Potomac River	12588	NRG Potomac River LLC	VA	NAICS-22 Non-Cogen	514	153,235	34,700		0	1	0	0	0
273	3796	Bremo Bluff	19876	Virginia Electric & Power Co	VA	Electric Utility	254	156,634	156,700		0	1	0	0	0
274	3797	Chesterfield	19876	Virginia Electric & Power Co	VA	Electric Utility	1,800	1,435,370	340,800		0	1	0	0	0
275	3803	Chesapeake	19876	Virginia Electric & Power Co	VA	Electric Utility	717	622,142	75,900		0	1	0	0	0
276	3809	Yorktown	19876	Virginia Electric & Power Co	VA	Electric Utility	1,257	257,133	24,900		0	1	0	0	0
277	3845	TransAlta Centralia Generation	19099	TransAlta Centralia Gen LLC	WA	NAICS-22 Non-Cogen	1,460	2,502,192	414,200		0	0	0	1	0
278	3935	John E Amos	733	Appalachian Power Co	WV	Electric Utility	2,933	5,161,580	1,048,000		0	1	0	0	0
279	3936	Kanawha River	733	Appalachian Power Co	WV	Electric Utility	439	468,890	60,500		0	1	0	0	0
280	3938	Philip Sporn	733	Appalachian Power Co	WV	Electric Utility	610	450,249	60,300		0	1	0	0	0
281	3942	FirstEnergy Albright	12796	Monongahela Power Co	WV	Electric Utility	278	91,230	18,100		0	1	0	0	0
282	3943	FirstEnergy Fort Martin Power Station	12796	Monongahela Power Co	WV	Electric Utility	1,152	2,360,814	671,200		0	1	0	1	0
283	3944	FirstEnergy Harrison Power Station	23279	Allegheny Energy Supply Co LLC	WV	NAICS-22 Non-Cogen	2,052	4,086,158	1,753,100		0	1	0	1	0

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Count	Plant Code	Plant Name	Utility Code	Company Name	State	Sector Name	Nameplate Capacity (MW/hour)	Annual Tons Coal Burned	Annual Tons CCR Generated	Src[1]	L I G	B I T	W C	S U B	S C
284	3945	FirstEnergy Rivesville	12796	Monongahela Power Co	WV	Electric Utility	110	942	800		0	1	0	0	0
285	3946	FirstEnergy Willow Island	12796	Monongahela Power Co	WV	Electric Utility	213	12,551	1,000		0	1	0	1	0
286	3947	Kammer	14006	Ohio Power Co	WV	Electric Utility	712	945,371	72,800		0	1	0	1	0
287	3948	Mitchell	14006	Ohio Power Co	WV	Electric Utility	1,633	3,035,147	645,700		0	1	0	0	0
288	3954	Mt Storm	19876	Virginia Electric & Power Co	WV	Electric Utility	1,681	3,543,119	795,700		0	1	0	0	0
289	3982	Bay Front	13781	Northern States Power Co - Minnesota	WI	Electric Utility	67	3,457	176	[2]	0	1	0	1	0
290	4041	South Oak Creek	20847	Wisconsin Electric Power Co	WI	Electric Utility	1,240	2,297,768	115,200		0	0	0	1	0
291	4042	Valley	20847	Wisconsin Electric Power Co	WI	Electric Utility	275	411,754	39,800		0	1	0	1	0
292	4050	Edgewater	20856	Wisconsin Power & Light Co	WI	Electric Utility	770	2,190,701	128,900		0	1	0	1	0
293	4054	Nelson Dewey Coal Refining Facility	20856	Wisconsin Power & Light Co	WI	Electric Utility	200	487,061	29,000		0	1	0	1	0
294	4057	Rock River	20856	Wisconsin Power & Light Co	WI	Electric Utility	169	0	39,248	[5,6]	0	0	0	0	0
295	4072	Pulliam	20860	Wisconsin Public Service Corp	WI	Electric Utility	441	390,131	32,000		0	0	0	1	0
296	4078	Weston	20860	Wisconsin Public Service Corp	WI	Electric Utility	1,163	2,737,536	202,000		0	0	0	1	0
297	4125	Manitowoc	11571	Manitowoc Public Utilities	WI	Electric Utility	123	6,663	14,400		0	1	0	1	0
298	4140	Alma	4716	Dairyland Power Coop	WI	Electric Utility	136	41,726	5,600		0	1	0	1	0
299	4143	Genoa	4716	Dairyland Power Coop	WI	Electric Utility	346	595,996	30,600		0	1	0	1	0
300	4150	Neil Simpson	19545	Black Hills Power Inc	WY	Electric Utility	22	135,890	7,387	[2]	0	0	0	1	0
301	4158	Dave Johnston	14354	PacifiCorp	WY	Electric Utility	817	3,382,634	180,900		0	0	0	1	0
302	4162	Naughton	14354	PacifiCorp	WY	Electric Utility	707	2,802,967	146,100		0	0	0	1	0
303	4259	Endicott Station	12807	Michigan South Central Pwr Agcy	MI	Electric Utility	58	126,589	15,135	[2]	0	1	0	0	0
304	4271	John P Madgett	4716	Dairyland Power Coop	WI	Electric Utility	387	1,209,042	55,000		0	0	0	1	0
305	4941	Navajo	16572	Salt River Project	AZ	Electric Utility	2,409	7,425,830	1,036,600		0	1	0	0	0
306	6002	James H Miller Jr	195	Alabama Power Co	AL	Electric Utility	2,822	10,257,937	645,100		0	0	0	1	0
307	6004	FirstEnergy Pleasants Power	23279	Allegheny Energy Supply Co LLC	WV	NAICS-22 Non-Cogen	1,368	3,337,559	969,800		0	1	0	0	0
308	6009	White Bluff	814	Entergy Arkansas Inc	AR	Electric Utility	1,800	5,813,676	281,500		0	0	0	1	0
309	6016	Duck Creek	49756	Ameren Energy Resources Generating Co.	IL	Electric Utility	441	1,545,819	128,300		0	1	0	1	0
310	6017	Newton	520	Ameren Energy Generating Co	IL	NAICS-22 Non-Cogen	1,235	3,310,156	179,600		0	1	0	1	0
311	6018	East Bend	55729	Duke Energy Kentucky Inc	KY	Electric Utility	669	1,535,488	943,800		0	1	0	0	1
312	6019	W H Zimmer	3542	Duke Energy Ohio Inc	OH	Electric Utility	1,426	2,011,114	855,800		0	1	0	0	0
313	6021	Craig	30151	Tri-State G & T Assn, Inc	CO	Electric Utility	1,428	4,629,443	361,900		0	0	0	1	0
314	6030	Coal Creek	7570	Great River Energy	ND	Electric Utility	1,212	7,225,818	1,202,100		1	0	0	0	0
315	6031	Killen Station	4922	Dayton Power & Light Co	OH	Electric Utility	689	1,610,257	577,600		0	1	0	0	1
316	6034	Belle River	5109	The DTE Electric Company	MI	Electric Utility	1,664	4,101,167	181,000		0	0	0	1	0
317	6041	H L Spurlock	5580	East Kentucky Power Coop, Inc	KY	Electric Utility	1,608	3,798,118	1,647,600		0	1	0	0	0
318	6052	Wansley	7140	Georgia Power Co	GA	Electric Utility	1,957	2,012,344	372,900		0	1	0	0	0
319	6055	Big Cajun 2	11252	Louisiana Generating LLC	LA	NAICS-22 Non-Cogen	1,903	6,639,986	330,000		0	0	0	1	0
320	6061	R D Morrow	17568	South Mississippi El Pwr Assn	MS	Electric Utility	400	485,527	52,400		0	1	0	0	0
321	6064	Nearman Creek	9996	City of Kansas City - (KS)	KS	Electric Utility	355	648,318	34,300		0	0	0	1	0
322	6065	Iatan	10000	Kansas City Power & Light Co	MO	Electric Utility	1,640	6,376,037	388,500		0	0	0	1	0
323	6068	Jeffrey Energy Center	22500	Westar Energy Inc	KS	Electric Utility	2,160	7,637,535	557,000		0	0	0	1	0
324	6071	Trimble County	11249	Louisville Gas & Electric Co	KY	Electric Utility	2,594	3,272,917	725,800		0	1	0	1	0
325	6073	Victor J Daniel Jr	12686	Mississippi Power Co	MS	Electric Utility	2,229	928,210	76,300		0	1	0	1	0
326	6076	Colstrip	15298	PPL Montana LLC	MT	NAICS-22 Non-Cogen	2,272	7,765,145	863,600		0	0	0	1	0
327	6077	Gerald Gentleman	13337	Nebraska Public Power District	NE	Electric Utility	1,363	5,310,305	241,600		0	0	0	1	0
328	6082	Somerset Operating Co LLC	22129	Somerset Operating Co LLC	NY	NAICS-22 Non-Cogen	655	859,731	225,900		0	1	0	1	0
329	6085	R M Schahfer	13756	Northern Indiana Pub Serv Co	IN	Electric Utility	2,201	3,444,927	425,300		0	1	0	1	0
330	6089	Lewis & Clark	12199	Montana-Dakota Utilities Co	MT	Electric Utility	50	247,783	23,235	[2]	1	0	0	1	0
331	6090	Sherburne County	13781	Northern States Power Co - Minnesota	MN	Electric Utility	2,469	5,022,075	409,700		0	0	0	1	0

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332	6094	FirstEnergy Bruce Mansfield	6526	FirstEnergy Generation Corp	PA	NAICS-22 Non-Cogen	2,741	7,168,875	681,300		0	1	0	1	0
333	6095	Sooner	14063	Oklahoma Gas & Electric Co	OK	Electric Utility	1,138	3,570,879	190,700		0	0	0	1	0
334	6096	Nebraska City	14127	Omaha Public Power District	NE	Electric Utility	1,390	5,470,519	420,400		0	0	0	1	0
335	6098	Big Stone	14232	Otter Tail Power Co	SD	Electric Utility	457	1,868,092	105,000		0	0	0	1	0
336	6101	Wyodak	14354	PacifiCorp	WY	Electric Utility	362	1,894,868	125,300		0	0	0	1	0
337	6106	Boardman	15248	Portland General Electric Co	OR	Electric Utility	642	1,583,129	75,700		0	0	0	1	0
338	6113	Gibson	15470	Duke Energy Indiana Inc	IN	Electric Utility	3,340	8,516,100	2,208,700		0	1	0	0	0
339	6124	McIntosh	7140	Georgia Power Co	GA	Electric Utility	988	0	229,449	[5,6]	0	1	0	0	0
340	6136	Gibbons Creek	18715	Texas Municipal Power Agency	TX	Electric Utility	454	989,997	64,200		0	0	0	1	0
341	6137	A B Brown	17633	Southern Indiana Gas & Elec Co	IN	Electric Utility	707	1,127,910	97,300		0	1	0	0	0
342	6138	Flint Creek	17698	Southwestern Electric Power Co	AR	Electric Utility	558	2,310,773	108,800		0	0	0	1	0
343	6139	Welsh	17698	Southwestern Electric Power Co	TX	Electric Utility	1,674	6,376,283	316,400		0	0	0	1	0
344	6146	Martin Lake	55983	Luminant Generation Company LLC	TX	NAICS-22 Non-Cogen	2,380	11,881,690	1,948,400		1	0	0	1	0
345	6147	Monticello	55983	Luminant Generation Company LLC	TX	NAICS-22 Non-Cogen	1,980	5,641,995	762,000		1	0	0	1	0
346	6155	Rush Island	19436	Union Electric Co - (MO)	MO	Electric Utility	1,242	4,712,946	229,300		0	0	0	1	0
347	6165	Hunter	14354	PacifiCorp	UT	Electric Utility	1,472	4,073,328	503,700		0	1	0	0	0
348	6166	Rockport	9324	Indiana Michigan Power Co	IN	Electric Utility	2,600	10,243,546	580,600		0	1	0	1	0
349	6170	Pleasant Prairie	20847	Wisconsin Electric Power Co	WI	Electric Utility	1,235	3,573,835	249,600		0	0	1	1	0
350	6177	Coronado	16572	Salt River Project	AZ	Electric Utility	822	3,496,113	253,700		0	0	0	1	0
351	6178	Coletto Creek	56570	Coletto Creek Power LP	TX	NAICS-22 Non-Cogen	622	2,990,449	155,700		0	0	0	1	0
352	6179	Fayette Power Project	11269	Lower Colorado River Authority	TX	Electric Utility	1,690	5,273,975	352,900		0	0	0	1	0
353	6180	Oak Grove	57097	Oak Grove Management Co LLC	TX	NAICS-22 Non-Cogen	1,795	8,498,111	1,645,700		1	0	0	0	0
354	6181	J T Deely	16604	City of San Antonio - (TX)	TX	Electric Utility	932	2,183,600	111,200		0	0	0	1	0
355	6183	San Miguel	16624	San Miguel Electric Coop, Inc	TX	Electric Utility	410	3,330,627	1,294,000		1	0	0	0	0
356	6190	Brame Energy Center	3265	Cleco Power LLC	LA	Electric Utility	1,707	2,147,282	482,700		1	1	0	1	0
357	6193	Harrington	17718	Southwestern Public Service Co	TX	Electric Utility	1,080	3,642,531	146,000		0	0	0	1	0
358	6194	Tolk	17718	Southwestern Public Service Co	TX	Electric Utility	1,136	4,263,700	187,000		0	1	0	1	0
359	6195	John Twitty Energy Center	17833	City Utilities of Springfield - (MO)	MO	Electric Utility	603	1,122,979	69,000		0	0	0	1	0
360	6204	Laramie River Station	1307	Basin Electric Power Coop	WY	Electric Utility	1,710	6,511,645	455,900		0	0	0	1	0
361	6213	Merom	9267	Hoosier Energy R E C, Inc	IN	Electric Utility	1,080	2,564,747	744,000		0	1	0	0	0
362	6225	Jasper 2	9667	City of Jasper - (IN)	IN	Electric Utility	14	150	12	[2]	0	1	0	0	0
363	6238	Pearl Station	40307	Prairie Power, Inc	IL	Electric Utility	24	2,474	192	[2]	0	1	0	0	0
364	6248	Pawnee	15466	Public Service Co of Colorado	CO	Electric Utility	552	2,036,994	80,100		0	0	0	1	0
365	6249	Winyah	17543	South Carolina Public Service Authority	SC	Electric Utility	1,260	1,138,184	250,700		0	1	0	0	1
366	6250	Mayo	3046	Progress Energy Carolinas Inc	NC	Electric Utility	736	1,607,604	307,300		0	1	0	0	0
367	6254	Ottumwa	9417	Interstate Power and Light Co	IA	Electric Utility	726	1,882,703	575,100		0	0	0	1	0
368	6257	Scherer	7140	Georgia Power Co	GA	Electric Utility	3,564	12,393,796	648,200		0	1	0	1	0
369	6264	Mountaineer	733	Appalachian Power Co	WV	Electric Utility	1,300	3,397,962	1,070,100		0	1	0	1	0
370	6288	Healy	7353	Golden Valley Elec Assn Inc	AK	Electric Utility	31	206,380	26,974	[2]	0	0	1	1	0
371	6469	Antelope Valley	1307	Basin Electric Power Coop	ND	Electric Utility	870	5,392,485	810,800		1	0	0	0	0
372	6481	Intermountain Power Project	11208	Los Angeles Department of Water & Power	UT	Electric Utility	1,640	4,374,658	705,100		0	1	0	1	0
373	6639	R D Green	1692	Big Rivers Electric Corp	KY	Electric Utility	586	1,043,827	317,600		0	1	0	0	0
374	6641	Independence	814	Entergy Arkansas Inc	AR	Electric Utility	1,800	6,367,438	306,000		0	0	0	1	0
375	6648	Sandow No 4	55983	Luminant Generation Company LLC	TX	NAICS-22 Non-Cogen	591	3,868,677	1,419,700		1	0	0	0	0
376	6664	Louisa	12341	MidAmerican Energy Co	IA	Electric Utility	812	3,180,759	191,300		0	0	0	1	0
377	6705	Warrick	261	AGC Division of APG Inc	IN	NAICS-22 Coagen	800	2,716,690	792,500		0	1	0	0	0

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378	6761	Rawhide	15143	Platte River Power Authority	CO	Electric Utility	800	1,177,887	70,900		0	0	0	1	0
379	6768	Sikeston Power Station	17177	City of Sikeston - (MO)	MO	Electric Utility	261	911,360	39,200		0	0	0	1	0
380	6772	Hugo	20447	Western Farmers Elec Coop, Inc	OK	Electric Utility	446	1,649,299	98,100		0	0	0	1	0
381	6823	D B Wilson	1692	Big Rivers Electric Corp	KY	Electric Utility	566	1,133,331	494,100		0	1	0	0	0
382	7030	Twin Oaks Power One	56598	Optim Energy LLC	TX	NAICS-22 Non-Cogen	349	1,346,682	397,900		1	0	0	0	0
383	7097	J K Spruce	16604	City of San Antonio - (TX)	TX	Electric Utility	1,444	5,421,333	361,900		0	0	0	1	0
384	7210	Cope	17539	South Carolina Electric&Gas Co	SC	Electric Utility	417	773,483	158,800		0	1	0	0	0
385	7213	Clover	19876	Virginia Electric & Power Co	VA	Electric Utility	848	1,812,923	359,600		0	1	0	0	0
386	7242	Polk	18454	Tampa Electric Co	FL	Electric Utility	1,030	455,808	12,318	[2]	0	1	0	0	0
387	7343	George Neal South	12341	MidAmerican Energy Co	IA	Electric Utility	640	2,595,157	121,700		0	0	0	1	0
388	7504	Neil Simpson II	19545	Black Hills Power Inc	WY	Electric Utility	120	432,377	25,472	[2]	0	0	0	1	0
389	7537	North Branch	19876	Virginia Electric & Power Co	WV	Electric Utility	80	0	18,579	[5,6]	0	0	0	0	0
390	7549	Milwaukee County	20847	Wisconsin Electric Power Co	WI	Electric Utility	11	56,215	4,652	[2]	0	1	0	0	0
391	7652	US DOE Savannah River Site (D Area)	56190	Savannah River Nuclear Solutions LLC	SC	NAICS-22 Cogen	78	36,220	3,094	[2]	0	1	0	0	0
392	7790	Bonanza	40230	Deseret Generation & Tran Coop	UT	Electric Utility	500	1,700,749	282,800		0	1	0	0	0
393	7902	Pirkey	17698	Southwestern Electric Power Co	TX	Electric Utility	721	3,544,819	664,300		1	0	0	0	0
394	8023	Columbia	20856	Wisconsin Power & Light Co	WI	Electric Utility	1,023	4,528,093	248,900		0	0	0	1	0
395	8042	Belews Creek	5416	Duke Energy Carolinas, LLC	NC	Electric Utility	2,160	5,218,995	716,900		0	1	0	0	0
396	8066	Jim Bridger	14354	PacifiCorp	WY	Electric Utility	2,318	7,527,469	848,600		0	0	0	1	0
397	8069	Huntington	14354	PacifiCorp	UT	Electric Utility	996	2,884,243	319,800		0	1	0	0	1
398	8102	General James M Gavin	14006	Ohio Power Co	OH	Electric Utility	2,600	7,139,309	1,751,900		0	1	0	1	0
399	8219	Ray D Nixon	39889	City of Colorado Springs - (CO)	CO	Electric Utility	279	912,339	60,700		0	1	0	1	0
400	8222	Coyote	14232	Otter Tail Power Co	ND	Electric Utility	450	1,823,960	158,000		1	0	0	0	0
401	8223	Springerville	24211	Tucson Electric Power Co	AZ	Electric Utility	1,759	5,714,820	1,151,600		0	0	0	1	0
402	8224	North Valmy	17166	Sierra Pacific Power Co	NV	Electric Utility	567	899,968	95,100		0	1	0	1	0
403	8226	Cheswick Power Plant	14165	NRG Power Midwest LP	PA	NAICS-22 Non-Cogen	637	1,024,882	333,700		0	1	0	0	0
404	10002	ACE Cogeneration Facility	52	ACE Cogeneration Co	CA	NAICS-22 Cogen	108	305,162	66,100		0	1	0	0	0
405	10003	Colorado Energy Nations Company	19173	Colorado Energy Nations Company LLLP	CO	NAICS-22 Cogen	35	215,918	20,592	[2]	0	1	0	0	0
406	10030	NRG Energy Center Dover	7860	NRG Energy Center Dover LLC	DE	NAICS-22 Cogen	118	25,721	2,058	[2]	0	1	0	0	0
407	10043	Logan Generating Company LP	14932	US Operating Services Company	NJ	NAICS-22 Cogen	242	313,672	73,900		0	1	0	0	0
408	10071	Portsmouth Genco LLC	56217	Portsmouth Operating Services	VA	NAICS-22 Non-Cogen	115	20,183	4,700		0	1	0	0	0
409	10075	Taconite Harbor Energy Center	12647	Minnesota Power Inc	MN	Electric Utility	252	564,415	28,000		0	0	0	1	0
410	10113	John B Rich Memorial Power Station	7199	Gilberton Power Co	PA	NAICS-22 Cogen	88	451,976	196,020	[2]	0	0	1	0	0
411	10143	Colver Power Project	9379	Inter-Power/AhlCon Partners, L.P.	PA	NAICS-22 Non-Cogen	118	672,808	426,800		0	0	1	0	0
412	10148	White Pine Electric Power	1951	White Pine Electric Power LLC	MI	NAICS-22 Non-Cogen	40	9,199	920	[2]	0	1	0	0	0
413	10151	Grant Town Power Plant	563	American Bituminous Power LP	WV	NAICS-22 Non-Cogen	96	600,550	215,525	[2]	0	1	1	0	0
414	10343	Foster Wheeler Mt Carmel Cogen	49889	Mount Carmel Cogen Inc	PA	NAICS-22 Cogen	47	577,370	365,150	[2]	0	0	1	0	0
415	10367	East Third Street Power Plant	7840	GWF Power Systems, L.P.	CA	NAICS-22 Non-Cogen	20	0	4,645	[5,6]	0	1	0	0	0
416	10369	Wilbur West Power Plant	7840	GWF Power Systems, L.P.	CA	NAICS-22 Non-Cogen	20	0	4,645	[5,6]	0	1	0	0	0
417	10370	Wilbur East Power Plant	7840	GWF Power Systems, L.P.	CA	NAICS-22 Non-Cogen	20	0	4,645	[5,6]	0	1	0	0	0
418	10371	Nichols Road Power Plant	7840	GWF Power Systems, L.P.	CA	NAICS-22 Non-Cogen	20	0	4,645	[5,6]	0	1	0	0	0
419	10377	James River Genco LLC	9628	Hopewell Operating Services LLC	VA	NAICS-22 Cogen	115	154,672	33,000		0	1	0	0	0

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420	10378	CPI USA NC Southport	58209	CPI USA NC Southport LLC	NC	NAICS-22 Cogen	135	69,561	4,555	[2]	0	1	0	0	0
421	10379	CPI USA NC Roxboro	58210	CPI USA NC Roxboro LLC	NC	NAICS-22 Cogen	68	24,325	1,148	[2]	0	1	0	0	0
422	10380	Elizabethtown Power LLC	13695	North Carolina Power Holdings, LLC	NC	NAICS-22 Cogen	35	0	8,059	[5,6]	0	0	0	0	0
423	10381	Coastal Carolina Clean Power	54889	Carlyle/Riverstone Renewable Energy	NC	NAICS-22 Cogen	44	0	10,218	[5,6]	0	1	0	0	0
424	10384	Edgecombe Genco LLC	55739	Edgecombe Operating Services LLC	NC	NAICS-22 Cogen	115	136,705	26,500		0	1	0	0	0
425	10464	Black River Generation	1746	Black River Generation LLC	NY	NAICS-22 Non-Cogen	56	0	13,005	[5,6]	0	1	1	0	0
426	10495	Rumford Cogeneration	54784	NewPage Corporation	ME	NAICS-22 Cogen	103	31,769	6,800		0	1	0	0	0
427	10566	Chambers Cogeneration LP	14932	US Operating Services Company	NJ	NAICS-22 Cogen	285	386,060	74,000		0	1	0	0	0
428	10603	Ebensburg Power	5670	Ebensburg Power Co	PA	NAICS-22 Cogen	58	553,577	251,183	[2]	0	0	1	0	0
429	10604	Hawaiian Comm & Sugar Puunene Mill	8286	Hawaiian Commercial and Sugar Company	HI	Industrial NAICS Cogen	46	49,786	4,464	[2]	0	1	0	0	0
430	10640	Stockton Cogen	353	Air Products Energy Enterprises LP	CA	NAICS-22 Cogen	60	37,972	3,897	[2]	0	1	0	0	0
431	10641	Cambria Cogen	2884	Cambria CoGen Co	PA	NAICS-22 Cogen	98	622,116	293,850	[2]	0	0	1	0	0
432	10671	AES Shady Point LLC	21	AES Shady Point LLC	OK	NAICS-22 Cogen	350	1,201,833	234,800		0	1	0	1	0
433	10672	Cedar Bay Generating Company LP	56730	Cedar Bay Operating Services LLC	FL	NAICS-22 Cogen	292	472,553	118,200		0	1	0	0	0
434	10673	AES Hawaii	177	AES Hawaii Inc	HI	NAICS-22 Cogen	203	753,466	122,600		0	1	0	1	0
435	10676	AES Beaver Valley Partners Beaver Valley	142	AES Beaver Valley	PA	NAICS-22 Cogen	149	539,601	170,700		0	1	0	0	0
436	10678	AES Warrior Run Cogeneration	35	AES WR Ltd Partnership	MD	NAICS-22 Cogen	229	665,628	359,000		0	1	1	0	0
437	10686	Rapids Energy Center	12647	Minnesota Power Inc	MN	Electric Utility	28	65,546	2,885	[2]	0	0	0	1	0
438	10743	Morgantown Energy Facility	12949	Morgantown Energy Associates	WV	NAICS-22 Cogen	69	384,890	154,945	[2]	0	1	1	0	0
439	10768	Rio Bravo Jasmin	16061	Rio Bravo Jasmin	CA	NAICS-22 Cogen	38	78,222	8,046	[2]	0	1	0	0	0
440	10769	Rio Bravo Poso	16002	Rio Bravo Poso	CA	NAICS-22 Cogen	38	54,352	5,956	[2]	0	1	0	1	0
441	10771	Hopewell Power Station	19876	Virginia Electric & Power Co	VA	Electric Utility	71	11,727	1,161	[2]	0	1	0	0	0
442	10774	Southampton Power Station	19876	Virginia Electric & Power Co	VA	Electric Utility	71	30,576	2,948	[2]	0	1	0	0	0
443	10784	Colstrip Energy LP	4217	Colstrip Energy LP	MT	NAICS-22 Non-Cogen	46	246,225	31,931	[2]	0	0	1	1	0
444	50039	Kline Township Cogen Facility	13833	Northeastern Power Co	PA	NAICS-22 Cogen	59	542,009	300,815	[2]	0	0	1	0	0
445	50202	WPS Power Niagara	55807	Niagara Generation LLC	NY	NAICS-22 Non-Cogen	56	4,125	858	[2]	0	1	0	0	0
446	50407	Mobile Energy Services LLC	34672	DTE Energy Services	AL	NAICS-22 Cogen	61	27,036	1,974	[2]	0	1	0	0	0
447	50611	Westwood Generation LLC	58224	Westwood Generation LLC	PA	NAICS-22 Non-Cogen	36	361,497	195,293	[2]	0	0	1	0	0
448	50651	Syracuse Energy	19194	Syracuse Energy Corp	NY	NAICS-22 Cogen	101	160,097	48,300		0	1	0	0	0
449	50776	Panther Creek Energy Facility	14432	Panther Creek Power Operating, LLC	PA	NAICS-22 Non-Cogen	94	686,518	259,370	[2]	0	0	1	0	0
450	50835	TES Filer City Station	18414	TES Filer City Station LP	MI	NAICS-22 Cogen	70	211,168	15,554	[2]	0	1	0	1	0
451	50879	Wheelabrator Frackville Energy	20541	Wheelabrator Environmental Systems	PA	NAICS-22 Cogen	48	528,569	304,839	[2]	0	1	1	0	0
452	50888	Northampton Generating	14932	US Operating Services Company	PA	NAICS-22 Cogen	114	663,764	463,400		0	0	1	0	0
453	50951	Sunnyside Cogen Associates	21734	Sunnyside Cogeneration Assoc	UT	NAICS-22 Non-Cogen	58	445,100	207,188	[2]	0	0	1	0	0
454	50974	Scrubgrass Generating Company	14932	US Operating Services Company	PA	NAICS-22 Non-Cogen	95	668,536	280,918	[2]	0	1	0	0	0
455	50976	Indiantown Cogeneration LP	14932	US Operating Services Company	FL	NAICS-22 Cogen	395	378,974	68,000		0	1	0	0	0
456	52007	Mecklenburg Power Station	19876	Virginia Electric & Power Co	VA	Electric Utility	140	80,981	15,100		0	1	0	0	0
457	54035	Roanoke Valley Energy Facility I	55808	Westmoreland Partners	NC	NAICS-22 Cogen	182	449,383	87,000		0	1	0	0	0
458	54081	Spruance Genco LLC	55740	Spruance Operating Services LLC	VA	NAICS-22 Cogen	230	361,641	91,000		0	1	0	0	0
459	54144	Piney Creek Project	4129	Colmac Clarion Inc	PA	NAICS-22 Non-Cogen	36	244,348	98,990	[2]	0	0	1	0	0
460	54304	Birchwood Power	1735	Birchwood Power Partners LP	VA	NAICS-22 Non-Cogen	258	173,261	29,700		0	1	0	0	0

Appendix A															
List of 478 Operating Electric Coal-Fired Utility Plants Potentially Affected by the CCR Rulemaking (2012)															
Count	Plant Code	Plant Name	Utility Code	Company Name	State	Sector Name	Nameplate Capacity (MW/hour)	Annual Tons Coal Burned	Annual Tons CCR Generated	Src[1]	L I G	B I T	W C	S U B	S C
461	54634	St Nicholas Cogen Project	16793	Schuylkill Energy Resource Inc	PA	NAICS-22 Cogen	99	1,500,903	921,925	[2]	0	0	1	0	0
462	54755	Roanoke Valley Energy Facility II	55808	Westmoreland Partners	NC	NAICS-22 Cogen	58	156,414	12,196	[2]	0	1	0	0	0
463	55076	Red Hills Generating Facility	3593	Choctaw Generating LP	MS	NAICS-22 Non-Cogen	514	3,065,671	637,200		1	0	0	0	0
464	55245	Tuscola Station	19145	DTE Tuscola, LLC	IL	Industrial NAICS Cogen	18	192,421	19,374	[2]	0	1	0	0	0
465	55479	Wygen 1	19545	Black Hills Power Inc	WY	NAICS-22 Non-Cogen	88	502,081	29,405	[2]	0	0	0	1	0
466	55749	Hardin Generator Project	16233	Rocky Mountain Power Inc	MT	NAICS-22 Non-Cogen	116	328,839	43,000		0	0	0	1	0
467	55856	Prairie State Generatng Station	15330	Prairie State Generating Co LLC	IL	NAICS-22 Non-Cogen	1,766	1,818,169	465,928	[2]	0	1	0	0	0
468	56068	Elm Road Generating Station	20847	Wisconsin Electric Power Co	WI	Electric Utility	1,403	753,073	152,800		0	1	0	0	0
469	56224	TS Power Plant	49896	Newmont Nevada Energy Investment, LLC	NV	NAICS-22 Non-Cogen	242	627,713	38,300		0	0	0	1	0
470	56319	Wygen 2	19545	Black Hills Power Inc	WY	Electric Utility	95	440,605	24,482	[2]	0	0	0	1	0
471	56456	Plum Point Energy Station	55995	Plum Point Energy Associates LLC	AR	NAICS-22 Non-Cogen	720	2,451,394	278,400		0	0	0	1	0
472	56564	John W Turk Jr Power Plant	17698	Southwestern Electric Power Co	AR	Electric Utility	609	79,423	3,677	[2]	0	0	0	1	0
473	56596	Wygen III	19545	Black Hills Power Inc	WY	Electric Utility	116	605,089	50,600		0	0	0	1	0
474	56609	Dry Fork Station	1307	Basin Electric Power Coop	WY	Electric Utility	390	2,029,604	84,900		0	0	0	1	0
475	56671	Longview Power LLC	55924	GenPower	WV	NAICS-22 Non-Cogen	808	1,694,079	664,600		0	1	0	0	0
476	56808	Virginia City Hybrid Energy Center	19876	Virginia Electric & Power Co	VA	Electric Utility	668	805,221	596,700		0	1	0	0	0
477	56848	Haverhill North Cogeneration Facility	56069	SunCoke Energy, Inc.	OH	NAICS-22 Cogen	67	0	15,560	[5,6]	0	1	0	0	0
478	68029	AES Puerto Rico Cogeneration Facility		AES Corporation	PR	Electric Utility	454	0	105,435	[5,6]	0	0	0	0	0
Totals								819,161,582	120,417,228		19	318	23	230	8
Notes:															
[1] "Src" - Source for Annual Tons CCR Generated. Annual Tons CCR Generated is the total managed quantity of byproducts as reported on EIA-923 for 2012, unless otherwise noted in this column.															
[2] Annual Tons CCR Generated is the actual total ash content of coal fuel that was burned in 2012, as reported on the EIA-923.															
[3] Annual Tons CCR Generated was calculated based on Annual Tons Coal Burned, from rates for sulfur and ash content reported on EIA-923 for 2012. Rates used for calculating sulfur and ash quantity were determined for each plant based on a weighted average for each fuel type burned by the plant. Individual fuel type rates were calculated by weighted average using rates reported on EIA-923 for purchases of the fuel type; rate was taken times quantity purchased, and sum result was divided by total quantity of fuel type. The resulting sulfur and ash rates were then applied to the Annual Tons Coal Burned by fuel type, and the results were summed. The result was used in place of reported CCR generation because plant did not submit a generation total (or showed zero) on the 2012 EIA-923.															
[4] Annual Tons CCR Generated was calculated based on Annual Tons Coal Burned, from industry average rates for sulfur and ash content for 2012 as reported on EIA-923. These rates were Rates used for calculating sulfur and ash quantity were determined for each plant based on a weighted average for each fuel type. Individual fuel type rates were calculated by weighted average using rates reported on EIA-923 for all purchases of the fuel type; rate was taken times quantity purchased, and sum result was divided by total quantity of fuel type to determine the reported average for 2012 by fuel type. The resulting sulfur and ash average rates were then applied to the Annual Tons Coal Burned by fuel type, and the results were summed. The result was used in place of reported CCR generation because plant did not submit a generation total (or showed zero) and did not report sulfur and ash rates for fuel types on the 2012 EIA-923.															
Ash Rate National Averages, 2012, by Fuel Type															
Code	Description	Ash													
BIT	Bituminous Coal	10.77%													
LIG	Lignite Coal	14.74%													
SUB	Sub-bituminous Coal	5.78%													
WC	Waste/Other Coal (includes anthracite culm, bituminous gob, fine coal, lignite waste, waste coal)	46.51%													

Appendix A														
List of 478 Operating Electric Coal-Fired Utility Plants Potentially Affected by the CCR Rulemaking (2012)														
Count	Plant Code	Plant Name	Utility Code	Company Name	State	Sector Name	Nameplate Capacity (MW/hour)	Annual Tons Coal Burned	Annual Tons CCR Generated	Src[1]	L I G	B I T	W C	S U B S C
	SC	Coal-based Synfuel (including briquettes, pellets, or extrusions, which are formed by binding materials or processes that recycle materials)	no data											

[5] EIA-923 reported no coal-based fuel was burned in 2012.

[6] Estimate ash generation assuming average utilization of 80% for coal plants, average of 266 days of operation per year, conversion of 2001.224 kWh per short ton of coal and average of 9.1 percent ash content in coal. Tons of ash = [(Nameplate Rating (kW) *266 days * 24 hours/day) *0.80 / (2001.224 kWhr/ton of coal)] * average ash content. Nameplate values are from 2012 EIA-860, or else 2009 EIA-860 if not available, with exception of plant code 68029, AES Puerto Rico, which uses the nameplate capacity as reported on AES's website: <http://www.aes.com/aes/index?page=country&cat=US>.

APPENDIX B

List of Other Industries with Coal-Fired Electricity Plants Not Covered by the Proposed Rule or this RIA

Appendix B List of Other Industries with Coal-Fired Electricity Plants Not Covered by the Proposed Rule or this RIA (2012)									
Plant Count**	Industry NAICS Code	State	Utility ID	Company	Plant ID	Plant Name	Coal-based Fuel (short tons)	Nameplate Capacity (megawatts/hour)*	Electricity Generation (megawatt hours)
1	311	IL	7	Tate & Lyle Ingredients Americas Inc	10867	Tate & Lyle Decatur Plant Cogen	73,943	62	241,207
2	311	IN	8	Tate & Lyle Ingredients Americas Inc	50903	Sagamore Plant Cogeneration	10,876	7	37,685
3	311	IA	109	Ag Processing Inc	10223	AG Processing Inc	13,165	8	48,999
4	311	ID	450	The Amalgamated Sugar Co	10504	Amalgamated Sugar Twin Falls	7,663	10	35,313
5	311	ND	491	American Crystal Sugar Co	54210	American Crystal Sugar Hillsboro	59,347	13	59,401
6	311	MN	491	American Crystal Sugar Co	54211	American Crystal Sugar Moorhead	12,608	5	46,948
7	311	MN	491	American Crystal Sugar Co	54212	American Crystal Sugar Crookston	8,498	6	31,659
8	311	ND	491	American Crystal Sugar Co	54213	American Crystal Sugar Drayton	8,301	6	0
9	311	MN	491	American Crystal Sugar Co	54214	American Crystal Sugar East Grand Forks	10,029	8	33,263
10	311	MO	623	Anheuser-Busch Inc	10430	Anheuser-Busch St Louis	25,569	26	45,510
11	311	IA	772	Archer Daniels Midland Co	10860	Archer Daniels Midland Clinton	416,089	180	724,329
12	311	IA	772	Archer Daniels Midland Co	10861	Archer Daniels Midland Des Moines	10,631	8	20,698
13	311	NE	772	Archer Daniels Midland Co	10862	Archer Daniels Midland Lincoln	13,200	8	46,088
14	311	MN	772	Archer Daniels Midland Co	10863	Archer Daniels Midland Mankato	3,797	6	8,427
15	311	IA	772	Archer Daniels Midland Co	10864	Archer Daniels Midland Cedar Rapids	321,312	256	978,128
16	311	IL	772	Archer Daniels Midland Co	10865	Archer Daniels Midland Decatur	445,610	335	1,151,052
17	311	IL	772	Archer Daniels Midland Co	10866	Archer Daniels Midland Peoria	51	64	257
18	311	ND	772	Archer Daniels Midland Co	55638	Walhalla	40	0	175
19	311	NE	772	Archer Daniels Midland Co	57046	Archer Daniels Midland Columbus	236,180	71	287,500
20	311	MI	2769	Cargill Inc	54965	Cargill Salt	1,319	2	7,746
21	311	TN	3103	Cargill Inc	10729	Cargill Corn Wet Milling Plant	3,197	25	18,204
22	311	IA	3106	Cargill Inc North America Sweeteners	10855	Cargill Corn Milling Division	30,945	40	103,686
23	311	IN	3283	Bunge North America East LLC	50316	Bunge North America East LLC	2,914	2	10,945
24	311	IL	4222	Ingredion Inc - Illinois	54556	Ingredion Illinois	79,144	55	290,360
25	311	NC	4417	Ingredion Inc - Winston Salem	54618	Ingredion Winston Salem	387	8	2,124
26	311	MN	17604	Southern Minnesota Beet Sugar	54533	Southern Minnesota Beet Sugar	2,559	8	11,229
27	311	ID	24206	Amalgamated Sugar Co-Nampa	54690	Amalgamated Sugar LLC Nampa	10,035	9	41,424
28	311	GA	27131	Imperial Savannah LP	50146	Imperial Savannah LP	2,290	12	11,624
29	311	MT	57296	Sidney Sugars Incorporated	57914	Sidney MT Plant	7,405	4	8,652
30	311	CA	57299	Spreckels Sugar Company	57916	Spreckels Sugar Company	0	9	0
31	311	NE	57315	Western Sugar Cooperative	57937	Western Sugar Coop - Scottsbluff	140,786	5	0
32	311	WY	57315	Western Sugar Cooperative	57967	Western Sugar Coop - Torrington	13,374	2	2,640
33	311	CO	57315	Western Sugar Cooperative	58081	Western Sugar Coop- Ft Morgan	64,591	3	8,326
34	311	MI	57324	Michigan Sugar Company	57949	MSC Sebewaing	28,808	2	0
35	311	MI	57324	Michigan Sugar Company	57950	MSC Croswell	17,871	1	2,189
36	311	IA	57332	Roquette America	57953	Roquette America	56,051	84	117,000
37	312	VA	14465	Park 500 Philip Morris USA	50275	Park 500 Philip Morris USA	9,474	19	45,739
38	312	GA	57316	Miller Coors LLC	57936	Albany Brewery	37,016	6	0
39	312	OH	57437	MillerCoors LLC Trenton Brewery	58059	MillerCoors Trenton Brewery	15,499	14	0
40	314	VA	57151	Celanese Acetate LLC	52089	Celanese Acetate LLC	23,897	27	125,528
41	321	MI	49967	Decorative Panels International, Inc.	10149	Decorative Panels Intl	2,286	8	13,033
42	322	AL	2053	Bowater Newport Coosa Pines Op	54216	U S Alliance Coosa Pines	5,041	30	24,933
43	322	WI	13008	Wausau Paper Specialty Products LLC	50614	Mosinee Paper	6,808	23	34,175
44	322	GA	16024	Riverwood Intl USA Inc	54464	Riverwood International Macon Mill	***	28.4	***
45	322	VA	17465	RockTenn-West Point Mill	10017	West Point Mill	20,634	101	107,096
46	322	WI	54876	Flambeau River Papers	50620	Flambeau River Papers	1,168	6	2,613
47	322	MI	56187	Verso Paper - Quinnesec	50251	Verso Paper Quinnesec Mich Mill	156	56	534
48	322	OH	57317	Wausau Paper Middletown	57940	Wausau Paper Middletown	40,295	8	0
49	322	MI	57442	PCA, Filer City Mill	58066	PCA, Filer City Mill	0	20	0
50	322	MI	58194	E.B. Eddy Paper Inc	58222	E.B. Eddy Paper Inc	12,790	5	28,112
51	322122	LA	1924	Boise Packaging & Newsprint LLC	10488	DeRidder Mill	0	62	0
52	322122	WI	5033	Domtar Industries Inc	50395	Georgia-Pacific Corp - Nekoosa Mill	20,107	38	85,317
53	322122	AR	5262	Domtar Industries Inc	54104	Ashdown	24,875	156	98,682
54	322122	OK	6589	Georgia-Pacific Consr Prods LP- Muskogee	10362	Muskogee Mill	182,012	114	376,607
55	322122	LA	7043	Temple-Inland Corp	54427	Gaylord Container Bogalusa	0	100	0
56	322122	GA	7127	Georgia-Pacific Consr Prods LP-Savannah	10361	Savannah River Mill	16,939	140	78,148
57	322122	AL	7136	Georgia-Pacific Consr Prods LP-Naheola	10699	Georgia-Pacific Consr Prods LP-Naheola	13,481	78	43,205
58	322122	ME	9303	Verso Bucksport LLC	50243	Verso Paper	74	298	402
59	322122	VA	9348	International Paper	52152	International Paper Franklin Mill	0	82	0
60	322122	AL	9384	International Paper Co-Courtld	50245	International Paper Courtland Mill	11,851	127	47,178
61	322122	SC	9390	International Paper Co-GT Mill	54087	International Paper Georgetown Mill	903	96	3,312
62	322122	FL	9401	International Paper Co-Pensacola	50250	International Paper Pensacola	880	83	4,420
63	322122	SC	9424	International Paper Co-Eastovr	52151	International Paper Eastover Facility	29,934	110	58,972
64	322122	PA	10273	Kimberly-Clark Corp	50410	Chester Operations	93,929	67	33,524

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Plant Count**	Industry NAICS Code	State	Utility ID	Company	Plant ID	Plant Name	Coal-based Fuel (short tons)	Nameplate Capacity (megawatts/hour)*	Electricity Generation (megawatt hours)
65	322122	PA	14310	P H Glatfelter Co	50397	P H Glatfelter	41,769	110	198,502
66	322122	WI	14369	Packaging Corp of America	50476	Packaging of America Tomahawk Mill	6,683	19	37,887
67	322122	ME	16721	S D Warren Co.- Westbrook	50447	S D Warren Westbrook	5,083	71	14,464
68	322122	GA	17610	SP Fiber Technologies LLC	54004	Dublin Mill	7,401	82	27,542
69	322122	FL	18157	Stone Container Corp-Panama Ci	50807	Stone Container Panama City Mill	1,971	34	9,356
70	322122	SC	18162	RockTenn-Florence	50806	Florence Mill	8,925	108	45,319
71	322122	MS	20492	Weyerhaeuser Co	50184	Weyerhaeuser Columbus MS	0	129	0
72	322122	WA	20548	Weyerhaeuser Co	50187	Weyerhaeuser Longview WA	9,043	59	34,521
73	322122	NC	23815	Blue Ridge Paper Products Inc	50244	Canton North Carolina	29,856	52	158,763
74	322122	TN	23931	Resolute Forest Products	50956	Bowater Newsprint Calhoun Operation	2,340	63	12,149
75	322122	MI	24263	Cellu Tissue Holdings Inc	52017	Menominee Acquisition	454	2	2,672
76	322122	WI	49801	Wausau Paper Mills LLC	50933	Rhineland Mill	6,639	21	30,222
77	322122	PA	49923	American Eagle Paper Mills	50284	American Eagle Paper Mills	10,012	18	44,918
78	322122	MI	50021	Neenah Paper Michigan Inc.	54867	Neenah Paper Munising Mill	6,083	6	32,227
79	322122	MD	50097	NewPage Corp-Luke	50282	Luke Mill	42,988	65	169,477
80	322122	LA	50129	Georgia-Pacific Consr Ops LLC-Port Hudson	10612	Georgia-Pacific Port Hudson	102	128	440
81	322122	WI	54738	Thilmany LLC	54098	Kaukauna Paper Mill	11,558	45	49,226
82	322122	ME	54784	NewPage Corporation	10491	Mead Rumford Cogen	0	12	0
83	322122	MN	54823	Wausau Paper Mills LLC	50636	Wausau Paper Mills LLC	239	3	851
84	322122	OH	54880	P H Glatfelter Company	10244	P H Glatfelter Co -Chillicothe Facility	54,921	93	190,057
85	322122	MI	55867	NewPage Corp-Escanaba	10208	Escanaba Paper Company	20,976	103	35,414
86	322122	NC	55903	Domtar Paper Company LLC	50189	Domtar Paper Co LLC Plymouth NC	0	146	0
87	322122	WI	55919	Georgia-Pacific Consr Prods LP-Green Bay	10360	Green Bay West Mill	74,043	129	321,953
88	322122	WI	55965	NewPage Corporation	10234	Biron Mill	66,700	62	234,513
89	322122	WI	55965	NewPage Corporation	10476	Whiting Mill	0	4	0
90	322122	WI	55965	NewPage Corporation	10477	Wisconsin Rapids Pulp Mill	16,291	72	51,712
91	322122	AZ	55973	Catalyst Paper Corp	50805	Catalyst Paper Snowflake Mill	57,800	0	185,179
92	322122	MN	56078	CMP Sartell LLC	50252	International Paper Sartell Mill	0	9	0
93	322122	PA	56137	Domtar LLC	54638	Johnsonburg Mill	40,094	54	90,816
94	322122	OH	56208	Smart Papers Holdings LLC	50247	Smart Papers LLC	0	0	0
95	32213	OH	2999	Caraustar Industries Inc	54235	Rittman Paperboard	0	14	0
96	32213	VA	7167	GP Big Island LLC	50479	Georgia-Pacific Big Island	54	8	257
97	32213	GA	7172	Georgia-PacificCedar Springs LLC	54101	Georgia-Pacific Cedar Springs	35,744	101	187,878
98	32213	AL	8009	International Paper Co	52140	International Paper Prattville Mill	11,745	90	56,000
99	32213	NC	9210	International Paper Co-Riegelwood	54656	International Paper Riegelwood Mill	0	62	0
100	32213	LA	9312	IPC-Mansfield Mill	54091	Mansfield Mill	0	135	0
101	32213	GA	9353	International Paper Co-Augusta	54358	International Paper Augusta Mill	2,551	85	10,955
102	32213	FL	9686	RockTenn-Jackson Fenandina	10202	Fernandina Beach Mill	49,333	118	218,815
103	32213	TN	14362	Packaging Corp of America	50296	Packaging Corp of America	181	72	914
104	32213	VA	18147	RockTenn-Hopewell	50813	Hopewell Mill	9,373	48	51,596
105	32213	VA	20508	MeadWestvaco Corp	50900	Covington Facility	53,738	100	268,815
106	32213	GA	23632	Inland Paperboard & Package Inc	10426	Inland Paperboard Packaging Rome	12,550	70	62,954
107	32213	GA	30002	International Paper Co	50398	International Paper Savanna Mill	34,430	154	138,572
108	32213	AL	50102	Rock-Tenn Company	54763	Rock-Tenn Mill	4,170	12	24,346
109	32213	NC	55771	KAPSTONE Kraft Paper Corp	50254	KapStone Kraft Paper Corp	21,643	22	109,210
110	32213	AL	56291	International Paper Co.	54752	Weyerhaeuser Pine Hill Operations	809	77	1,528
111	32213	SC	57302	Sonoco Products Co	57919	Sonoco Products Co	25,379	40	42,621
112	324	OH	56069	SunCoke Energy, Inc.	57822	Middletown Coke Company, LLC	0	67	0
113	325	TN	5610	Eastman Chemical Co-TN Ops	50481	Tennessee Eastman Operations	228,521	194	1,119,405
114	325	OH	12986	Morton Salt Inc	54335	Morton Salt Rittman	1,144	2	6,464
115	325	WV	19433	Union Carbide C&P-Charleston	50151	Union Carbide South Charleston	0	6	0
116	325	VA	22218	U S Army-Radford	52072	Radford Army Ammunition Plant	7,048	24	29,395
117	325	WV	50033	PPG Industries Inc Natrium	50491	PPG Natrium Plant	88,834	123	382,046
118	325	WY	57297	FMC Westvaco	57915	FMC Westvaco	132,484	41	214,450
119	325188	WY	7067	Tata Chemicals Partners	54318	General Chemical	38,298	30	193,862
120	325188	CA	49968	Searles Valley Minerals Operations Inc.	10684	Argus Cogen Plant	74,009	62	370,555
121	325211	MA	39878	Solutia Inc-Indian	10417	Indian Orchard Plant 1	4,620	6	23,509
122	325211	SC	50006	Invista	10795	Camden South Carolina	2,283	24	11,235
123	3253	WV	57300	Bayer CropScience	57917	Bayer CropScience Institute Plant	14,265	13	31,189
124	327	MA	16544	Saint - Gobain Abrasives Inc	50041	Norton Powerhouse	686	6	3,417
125	327	TX	35120	Norit Americas Inc	54972	Norit Americas Marshall Plant	289,899	0	53
126	327	MI	40430	LaFarge Corp	50305	LaFarge Alpena	16,717	47	82,245
127	327	WI	55755	Fox Valley Energy Center LLC	56037	Fox Valley Energy Center	0	6	0
128	331	MN	3807	Cleveland Cliffs Inc	10849	Silver Bay Power	281,747	132	483,557
129	331	UT	49805	Kennecott Utah Copper	56163	Kennecott Power Plant	220,093	220	405,286

Appendix B									
List of Other Industries with Coal-Fired Electricity Plants Not Covered by the Proposed Rule or this RIA (2012)									
Plant Count**	Industry NAICS Code	State	Utility ID	Company	Plant ID	Plant Name	Coal-based Fuel (short tons)	Nameplate Capacity (megawatts/hour)*	Electricity Generation (megawatt hours)
130	331111	PA	5959	Erie Coke Corp	50920	Erie Coke	0	2	0
131	331111	OH	9454	ArcelorMittal Cleveland Inc	10398	Arcelormittal Cleveland Inc	0	53	0
132	331111	OH	56616	ArcelorMittal Warren Inc	54207	ArcelorMittal Warren	0	20	0
133	333	IA	9765	John Deere Dubuque Works	54414	John Deere Dubuque Works	0	9	0
134	333	IL	9788	John Deere Harvester Works Co	10039	John Deere Harvester Works	2,225	8	6,466
135	336	MO	57310	General Motors LLC	57932	Wentzville Assembly & Contiguous	123	3	266
136	339	NY	5624	RED-Rochester, LLC	10025	RED-Rochester, LLC	69,943	130	315,331
137	339	OH	15400	Procter & Gamble Co	50456	Procter & Gamble Cincinnati Plant	9,074	12	43,547
138	482	PA	13657	Norfolk Southern Corp	10302	Juniata Locomotive Shop	316	4	1,836
139	541	MD	57322	Naval Facilities Engineering Command	57944	Goddard Steam Plant	19,231	12	9,850
140	611	IA	9434	Iowa State University	54201	Iowa State University	36,299	46	130,571
141	611	MI	12436	Michigan State University	10328	T B Simon Power Plant	27,883	99	118,082
142	611	IN	15526	Purdue University	50240	Purdue University	32,922	43	117,686
143	611	WI	18028	State of Wisconsin	54408	UW Madison Charter Street Plant	106	10	594
144	611	AK	19511	University of Alaska	50711	University of Alaska Fairbanks	20,503	23	46,074
145	611	IL	19528	University of Illinois	54780	University of Illinois Abbott Power Plt	7,232	85	31,073
146	611	IA	19539	University of Iowa	54775	University of Iowa Main Power Plant	4,391	23	21,948
147	611	NC	19541	University of North Carolina	54276	Univ of NC Chapel Hill Cogen Facility	8,177	32	28,831
148	611	IN	19564	University of Notre Dame	50366	University of Notre Dame	3,496	29	15,427
149	611	TN	19724	Vanderbilt University	52048	Vanderbilt University Power Plant	4,237	21	20,234
150	611	IA	21223	University of Northern Iowa	50088	University of Northern Iowa	1,979	8	6,717
151	611	NY	21508	Cornell University	50368	Cornell University Central Heat	0	38	0
152	611	MO	34359	Curators of the University of Missouri	50969	MU Combined Heat and Power Plant	21,015	91	68,443
153	611	VA	55988	Virginia Polytechnic Inst and State Univ	56785	Virginia Tech Power Plant	4,024	6	9,096
154	611	OH	57281	University of Cincinnati	57929	East Campus Utility Plant	923	5	0
155	611	IL	57306	Southern Illinois University Carbondale	57928	SIUC	8,828	5	16,562
156	611	MN	57341	Foster Wheeler Twin Cities	57966	Southeast Steam Plant	618	13	0
157	611	PA	58159	Penn State University	58194	West Campus Steam Plant	4,097	6	9,503
158	623	IL	57303	State of Illinois	57918	Jacksonville Developmental Center	14,000	3	4,322
159	624	MD	11704	Maryland Environmental Service	10693	Eastern Correctional Institute	0	6	0
160	624	WI	18028	State of Wisconsin	54407	Waupun Correctional Central Heating Plt	659	4	1,567
161	92	WI	18028	State of Wisconsin	54406	Capitol Heat and Power	0	2	0
162	92	AK	56389	Doyon Utilities - Ft. Wainwright	50308	Utility Plants Section	57,585	20	149,725
163	92	OH	57305	Wright Patterson AFB	57926	Heat Plant 770	1,046	2	2,395
164	928	AK	22199	U S Air Force-Eielson AFB	50392	Eielson AFB Central Heat & Power Plant	27,030	34	72,445
Total							5,280,915	8,069	13,402,214
Notes:									
(a) Source: Nameplate capacity is from US Dept of Energy, Energy Information Administration (EIA), 2012, "Form EIA-860 Annual Electric Generator Report," Existing Electric Generating Units in the United States, 2012, at http://www.eia.gov/cneaf/electricity/page/eia860.html ; All other data is from US Dept of Energy, Energy Information Administration (EIA), 2009, "Form EIA-923 January - December Final, Nonutility Energy Balance and Annual Environmental Information Data," 2012, at http://www.eia.gov/cneaf/electricity/page/eia906_920.html									
(b) NAICS codes: The first two digits designate the economic sector, the third digit designates the subsector, the fourth digit designates the industry group, the fifth digit designates the NAICS industry, and the sixth digit designates the national industry. The five-digit NAICS code is the level at which there is comparability in code and definitions for most of the NAICS sectors across the three countries participating in NAICS (the United States, Canada, and Mexico). The six-digit level allows for the United States, Canada, and Mexico each to have country-specific detail. A complete and valid NAICS code contains six digits. Source: http://www.census.gov/eos/www/naics/faqs/faqs.html#q5									
* Non-coal fuel types may contribute to the nameplate capacity total. Plants are included only if they have a generator that reported having a coal-based fuel type as a potential fuel source.									
** Twenty-four plants reported use of coal-based fuel by generators at the plant, but the quantity for 2012 was zero short tons.									
*** One plant submitted EIA-860 in 2012 reporting generators that use coal-based fuel (Plant ID 54464, Riverwood International Macon Mill); this plants did not submit EIA-923 in 2012, so fuel and electricity quantities are not available.									

APPENDIX C

Small Business Owner Information

Note: EPA has updated the universe to reflect 61 actual and projected plant retirements occurring after 2012 according to the National Electric Energy Data System (NEEDS) v.5.13 dataset; see **Section 9.2.1** in **Chapter 9** for a description of the relevant updates. Exhibits in this appendix have not been updated to reflect the revisions described in **Section 9.2.1**.

Exhibit C-1: Identity and Business Size of Parent Companies Which Own the 478 Potentially Affected Coal-Fired Electric Utility Plants (2013)

Exhibit C-2: Revenues and Costs Used for SBREFA and UMRA/Federalism Calculation

Exhibit C-1

Identity and Business Size of Parent Companies Which Own the 478 Potentially Affected Coal-Fired Electric Utility Plants (2013)

Item	Plant Code	Parent Company Owner Name	Electric Utility Plant Name (NAICS 22)	Plant Location State	Owner Business Size & Type of Business Entity	Size Type/ Count	Owner Entity Count
1	1122	City of Ames - (IA)	Ames Electric Services Power Plant	IA	Non-Small City	1	1
2	492	Colorado Springs City of	Martin Drake	CO	Non-Small City	2	2
3	8219	Colorado Springs City of	Ray D Nixon	CO	Non-Small City	3	2
4	2123	City of Columbia	Columbia	MO	Non-Small City	4	3
5	663	Gainesville Regional Utilities	Deerhaven Generating Station	FL	Non-Small City	5	4
6	2917	City of Hamilton	Hamilton	OH	Non-Small City	6	5
7	2132	Independence City of	Independence Power & Light - Blue Valley Station	MO	Non-Small City	7	6
8	2171	Independence City of	Missouri City	MO	Non-Small City	8	6
9	207	JEA	St Johns River Power Park	FL	Non-Small City	9	7
10	667	JEA	Northside Generating Station	FL	Non-Small City	10	7
11	1295	Kansas City City of	Quindaro	KS	Non-Small City	11	8
12	6064	Kansas City City of	Nearman Creek	KS	Non-Small City	12	8
13	676	City of Lakeland	C D McIntosh Jr	FL	Non-Small City	13	9
14	6481	Los Angeles City of	Intermountain Power Project	UT	Non-Small City	14	10
15	1374	City of Owensboro	Elmer Smith Station	KY	Non-Small City	15	11
16	564	Orlando Utilities Comm	Stanton Energy Center	FL	Non-Small City	16	12
17	2008	Rochester Public Utilities	Silver Lake	MN	Non-Small City	17	13
18	6181	San Antonio City of	J T Deely	TX	Non-Small City	18	14
19	7097	San Antonio City of	J K Spruce	TX	Non-Small City	19	14
20	963	City of Springfield	Dallman	IL	Non-Small City	20	15
21	2161	City Utilities of Springfield	James River Power Station	MO	Non-Small City	21	16
22	6195	City Utilities of Springfield	Southwest Power Station	MO	Non-Small City	22	16
23	2434	Vineland City of	Howard Down	NJ	Non-Small City	23	17
24	1831	Lansing Board of Water and Light	Otto E. Eckert Station	MI	Non-Small City	24	18
25	1832	Lansing Board of Water and Light	Erickson Station	MI	Non-Small City	25	18
26	10671	AES Shady Point LLC	AES Shady Point,LLC	OK	Non-Small Company	1	19
27	2527	AES Greenidge	AES Greenidge	NY	Non-Small Company	2	20
28	10678	AES WR Ltd Partnership	AES Warrior Run Cogeneration Facility	MD	Non-Small Company	3	21
29	10002	ACE Cogeneration Co	ACE Cogeneration Company	CA	Non-Small Company	4	22
30	10676	AES Beaver Valley	AES Beaver Valley	PA	Non-Small Company	5	23

Exhibit C-1

Identity and Business Size of Parent Companies Which Own the 478 Potentially Affected Coal-Fired Electric Utility Plants (2013)

Item	Plant Code	Parent Company Owner Name	Electric Utility Plant Name (NAICS 22)	Plant Location State	Owner Business Size & Type of Business Entity	Size Type/ Count	Owner Entity Count
31	10673	AES Hawaii Inc	AES Hawaii	HI	Non-Small Company	6	24
32	3	Alabama Power Co	Barry	AL	Non-Small Company	7	25
33	7	Alabama Power Co	Gadsden	AL	Non-Small Company	8	25
34	8	Alabama Power Co	Gorgas	AL	Non-Small Company	9	25
35	10	Alabama Power Co	Greene County	AL	Non-Small Company	10	25
36	26	Alabama Power Co	E. C. Gaston	AL	Non-Small Company	11	25
37	6002	Alabama Power Co	James H. Miller Jr.	AL	Non-Small Company	12	25
38	6705	AGC Division of APG Inc	Warrick Power Plant	IN	Non-Small Company	13	26
39	861	Ameren Energy Generating Co	Coffeen	IL	Non-Small Company	14	27
40	6017	Ameren Energy Generating Co	Newton	IL	Non-Small Company	15	27
41	10151	American Bituminous Power LP	Grant Town Power Plant	WV	Non-Small Company	16	28
42	3775	Appalachian Power Co	Clinch River	VA	Non-Small Company	17	29
43	3776	Appalachian Power Co	Glen Lyn	VA	Non-Small Company	18	29
44	3935	Appalachian Power Co	John E. Amos	WV	Non-Small Company	19	29
45	3936	Appalachian Power Co	Kanawha River	WV	Non-Small Company	20	29
46	3938	Appalachian Power Co	Philip Sporn	WV	Non-Small Company	21	29
47	6264	Appalachian Power Co	Mountaineer	WV	Non-Small Company	22	29
48	113	Arizona Public Service Co	Cholla	AZ	Non-Small Company	23	30
49	2442	Arizona Public Service Co	Four Corners	NM	Non-Small Company	24	30
50	6009	Entergy Arkansas Inc	White Bluff	AR	Non-Small Company	25	31
51	6641	Entergy Arkansas Inc	Independence	AR	Non-Small Company	26	31
52	6180	TXU Generation Co LP	Oak Grove	TX	Non-Small Company	27	32
53	68029	AES Corporation	AES Puerto Rico Cogeneration Facility	PR	Non-Small Company	28	33
54	54304	Birchwood Power Partners LP	Birchwood Power Facility	VA	Non-Small Company	29	34
55	2706	Progress Energy Carolinas Inc	Asheville Steam Electric Plant	NC	Non-Small Company	30	35
56	2708	Progress Energy Carolinas Inc	Cape Fear Steam Electric Plant	NC	Non-Small Company	31	35
57	2709	Progress Energy Carolinas Inc	H.F. Lee Plant	NC	Non-Small Company	32	35
58	2712	Progress Energy Carolinas Inc	Roxboro Steam Electric Plant	NC	Non-Small Company	33	35
59	2713	Progress Energy Carolinas Inc	L.V. Sutton Electric Plant	NC	Non-Small Company	34	35
60	3251	Progress Energy Carolinas Inc	HB Robinson / Darlington Electric Power Plant	SC	Non-Small Company	35	35

Exhibit C-1

Identity and Business Size of Parent Companies Which Own the 478 Potentially Affected Coal-Fired Electric Utility Plants (2013)

Item	Plant Code	Parent Company Owner Name	Electric Utility Plant Name (NAICS 22)	Plant Location State	Owner Business Size & Type of Business Entity	Size Type/ Count	Owner Entity Count
61	6250	Progress Energy Carolinas Inc	Mayo Electric Generating Facility	NC	Non-Small Company	36	35
62	51	Cleco Power LLC	Dolet Hills	LA	Non-Small Company	37	36
63	6190	Cleco Power LLC	Rodemacher	LA	Non-Small Company	38	36
64	2830	Duke Energy Ohio Inc	Walter C Beckjord	OH	Non-Small Company	39	37
65	2832	Duke Energy Ohio Inc	Miami Fort	OH	Non-Small Company	40	37
66	6019	Duke Energy Ohio Inc	W H Zimmer	OH	Non-Small Company	41	37
67	55076	Choctaw Generating LP	Red Hills Generating Facility	MS	Non-Small Company	42	38
68	992	Citizens Thermal Energy	CC Perry K	IN	Non-Small Company	43	39
69	2840	Columbus Southern Power Co	Conesville	OH	Non-Small Company	44	40
70	2843	Columbus Southern Power Co	Picway	OH	Non-Small Company	45	40
71	54144	Colmac Clarion Inc	Piney Creek Project	PA	Non-Small Company	46	41
72	602	Constellation Power Source Gen	Brandon Shores	MD	Non-Small Company	47	42
73	1552	Constellation Power Source Gen	Charles P. Crane	MD	Non-Small Company	48	42
74	1554	Constellation Power Source Gen	Herbert A. Wagner	MD	Non-Small Company	49	42
75	1695	Consumers Energy Co	B.C. Cobb	MI	Non-Small Company	50	43
76	1702	Consumers Energy Co	D.E. Karn	MI	Non-Small Company	51	43
77	1710	Consumers Energy Co	Consumers Energy - J.H. Campbell	MI	Non-Small Company	52	43
78	1720	Consumers Energy Co	J.C. Weadock	MI	Non-Small Company	53	43
79	1723	Consumers Energy Co	J.R Whiting	MI	Non-Small Company	54	43
80	2848	Dayton Power & Light Co	O H Hutchings	OH	Non-Small Company	55	44
81	2850	Dayton Power & Light Co	J M Stuart	OH	Non-Small Company	56	44
82	6031	Dayton Power & Light Co	Killen Station	OH	Non-Small Company	57	44
83	1731	Detroit Edison Co	Harbor Beach Power Plant	MI	Non-Small Company	58	45
84	1733	Detroit Edison Co	Monroe Power Plant	MI	Non-Small Company	59	45
85	1740	Detroit Edison Co	River Rouge Power Plant	MI	Non-Small Company	60	45
86	1743	Detroit Edison Co	St Clair Power Plant	MI	Non-Small Company	61	45
87	1745	Detroit Edison Co	Trenton Channel Power Plant	MI	Non-Small Company	62	45
88	6034	Detroit Edison Co	Belle River	MI	Non-Small Company	63	45
89	876	Dominion Energy Services Co	Kincaid Generation LLC	IL	Non-Small Company	64	46
90	2718	Duke Energy Carolinas, LLC	G G Allen	NC	Non-Small Company	65	47
91	2720	Duke Energy Carolinas, LLC	Buck	NC	Non-Small Company	66	47

Exhibit C-1

Identity and Business Size of Parent Companies Which Own the 478 Potentially Affected Coal-Fired Electric Utility Plants (2013)

Item	Plant Code	Parent Company Owner Name	Electric Utility Plant Name (NAICS 22)	Plant Location State	Owner Business Size & Type of Business Entity	Size Type/ Count	Owner Entity Count
92	2721	Duke Energy Carolinas, LLC	Cliffside	NC	Non-Small Company	67	47
93	2727	Duke Energy Carolinas, LLC	Marshall	NC	Non-Small Company	68	47
94	2732	Duke Energy Carolinas, LLC	Riverbend	NC	Non-Small Company	69	47
95	3264	Duke Energy Carolinas, LLC	W. S. Lee	SC	Non-Small Company	70	47
96	8042	Duke Energy Carolinas, LLC	Belews Creek Steam Station	NC	Non-Small Company	71	47
97	889	Dynegy Midwest Generation Inc	Baldwin Energy Complex	IL	Non-Small Company	72	48
98	891	Dynegy Midwest Generation Inc	Havana	IL	Non-Small Company	73	48
99	892	Dynegy Midwest Generation Inc	Hennepin Power Station	IL	Non-Small Company	74	48
100	898	Dynegy Midwest Generation Inc	Wood River	IL	Non-Small Company	75	48
101	10603	Ebensburg Power Co	Ebensburg Power Company	PA	Non-Small Company	76	49
102	887	Electric Energy Inc	Joppa Steam	IL	Non-Small Company	77	50
103	628	Progress Energy Florida Inc	Crystal River Power Plant	FL	Non-Small Company	78	51
104	2835	FirstEnergy Generation Corp	Ashtabula	OH	Non-Small Company	79	52
105	2837	FirstEnergy Generation Corp	Eastlake	OH	Non-Small Company	80	52
106	2838	FirstEnergy Generation Corp	Lake Shore	OH	Non-Small Company	81	52
107	2866	FirstEnergy Generation Corp	W. H. Sammis	OH	Non-Small Company	82	52
108	2878	FirstEnergy Generation Corp	Bay Shore	OH	Non-Small Company	83	52
109	6094	FirstEnergy Generation Corp	Bruce Mansfield	PA	Non-Small Company	84	52
110	703	Georgia Power Co	Bowen	GA	Non-Small Company	85	53
111	708	Georgia Power Co	Hammond	GA	Non-Small Company	86	53
112	709	Georgia Power Co	Harlee Branch	GA	Non-Small Company	87	53
113	710	Georgia Power Co	Jack McDonough	GA	Non-Small Company	88	53
114	727	Georgia Power Co	Mitchell	GA	Non-Small Company	89	53
115	728	Georgia Power Co	Yates	GA	Non-Small Company	90	53
116	733	Georgia Power Co	Kraft	GA	Non-Small Company	91	53
117	6052	Georgia Power Co	Wansley	GA	Non-Small Company	92	53
118	6124	Georgia Power Co	McIntosh	GA	Non-Small Company	93	53
119	6257	Georgia Power Co	Scherer	GA	Non-Small Company	94	53
120	641	Gulf Power Co	Crist	FL	Non-Small Company	95	54
121	642	Gulf Power Co	Scholz	FL	Non-Small Company	96	54
122	643	Gulf Power Co	Lansing Smith	FL	Non-Small Company	97	54

Exhibit C-1

Identity and Business Size of Parent Companies Which Own the 478 Potentially Affected Coal-Fired Electric Utility Plants (2013)

Item	Plant Code	Parent Company Owner Name	Electric Utility Plant Name (NAICS 22)	Plant Location State	Owner Business Size & Type of Business Entity	Size Type/ Count	Owner Entity Count
123	10367	GWF Power Systems, L.P.	East Third Street Power Plant	CA	Non-Small Company	98	55
124	10369	GWF Power Systems, L.P.	Wilbur West Power Plant	CA	Non-Small Company	99	55
125	10370	GWF Power Systems, L.P.	Wilbur East Power Plant	CA	Non-Small Company	100	55
126	10371	GWF Power Systems, L.P.	Nichols Road Power Plant	CA	Non-Small Company	101	55
127	10030	NRG Energy Center Dover LLC	NRG Energy Center Dover	DE	Non-Small Company	102	56
128	10604	Hawaiian Com & Sugar Co Ltd	Hawaiian Comm & Sugar Puunene Mill	HI	Non-Small Company	103	57
129	983	Indiana-Kentucky Electric Corp	Clifty Creek	IN	Non-Small Company	104	58
130	990	Indianapolis Power & Light Co	Harding Street	IN	Non-Small Company	105	59
131	991	Indianapolis Power & Light Co	Eagle Valley	IN	Non-Small Company	106	59
132	994	Indianapolis Power & Light Co	AES Petersburg	IN	Non-Small Company	107	59
133	988	Indiana Michigan Power Co	Tanners Creek	IN	Non-Small Company	108	60
134	6166	Indiana Michigan Power Co	Rockport	IN	Non-Small Company	109	60
135	594	Indian River Operations Inc	Indian River Generating Station	DE	Non-Small Company	110	61
136	1046	Interstate Power and Light Co	Dubuque	IA	Non-Small Company	111	62
137	1047	Interstate Power and Light Co	Lansing	IA	Non-Small Company	112	62
138	1048	Interstate Power and Light Co	ML Kapp	IA	Non-Small Company	113	62
139	1073	Interstate Power and Light Co	Prairie Creek	IA	Non-Small Company	114	62
140	1077	Interstate Power and Light Co	Sutherland	IA	Non-Small Company	115	62
141	1104	Interstate Power and Light Co	Burlington	IA	Non-Small Company	116	62
142	6254	Interstate Power and Light Co	Ottumwa	IA	Non-Small Company	117	62
143	1241	Kansas City Power & Light Co	La Cygne	KS	Non-Small Company	118	63
144	2079	Kansas City Power & Light Co	Hawthorn	MO	Non-Small Company	119	63
145	2080	Kansas City Power & Light Co	Montrose	MO	Non-Small Company	120	63
146	6065	Kansas City Power & Light Co	Iatan	MO	Non-Small Company	121	63
147	1355	Kentucky Utilities Co	E.W. Brown	KY	Non-Small Company	122	64
148	1356	Kentucky Utilities Co	Ghent	KY	Non-Small Company	123	64
149	1357	Kentucky Utilities Co	Green River	KY	Non-Small Company	124	64
150	1361	Kentucky Utilities Co	Tyrone	KY	Non-Small Company	125	64
151	1363	Louisville Gas & Electric Co	Cane Run	KY	Non-Small Company	126	65
152	1364	Louisville Gas & Electric Co	Mill Creek	KY	Non-Small Company	127	65
153	6071	Louisville Gas & Electric Co	Trimble Co.	KY	Non-Small Company	128	65

Exhibit C-1

Identity and Business Size of Parent Companies Which Own the 478 Potentially Affected Coal-Fired Electric Utility Plants (2013)

Item	Plant Code	Parent Company Owner Name	Electric Utility Plant Name (NAICS 22)	Plant Location State	Owner Business Size & Type of Business Entity	Size Type/ Count	Owner Entity Count
154	6055	Louisiana Generating LLC	Big Cajun 2	LA	Non-Small Company	129	66
155	2790	Montana-Dakota Utilities Co	R.M. Heskett Station	ND	Non-Small Company	130	67
156	6089	Montana-Dakota Utilities Co	Lewis & Clark	MT	Non-Small Company	131	67
157	1081	MidAmerican Energy Co	Riverside	IA	Non-Small Company	132	68
158	1082	MidAmerican Energy Co	Walter Scott Jr. Energy Center	IA	Non-Small Company	133	68
159	1091	MidAmerican Energy Co	George Neal North	IA	Non-Small Company	134	68
160	6664	MidAmerican Energy Co	Louisa	IA	Non-Small Company	135	68
161	7343	MidAmerican Energy Co	George Neal South	IA	Non-Small Company	136	68
162	384	Midwest Generations EME LLC	Joliet 29	IL	Non-Small Company	137	69
163	867	Midwest Generations EME LLC	Crawford	IL	Non-Small Company	138	69
164	874	Midwest Generations EME LLC	Joliet 9	IL	Non-Small Company	139	69
165	879	Midwest Generations EME LLC	Powerton	IL	Non-Small Company	140	69
166	883	Midwest Generations EME LLC	Waukegan	IL	Non-Small Company	141	69
167	884	Midwest Generations EME LLC	Will County	IL	Non-Small Company	142	69
168	886	Midwest Generations EME LLC	Fisk	IL	Non-Small Company	143	69
169	3122	Midwest Generations EME LLC	Homer City Station	PA	Non-Small Company	144	69
170	3788	Mirant Potomac River LLC	Potomac River	VA	Non-Small Company	145	70
171	1571	Mirant Chalk Point LLC	Chalk Point LLC	MD	Non-Small Company	146	71
172	1891	Minnesota Power Inc	Laskin Energy Center	MN	Non-Small Company	147	72
173	1893	Minnesota Power Inc	Boswell Energy Center	MN	Non-Small Company	148	72
174	1897	Minnesota Power Inc	Hibbard Energy Center	MN	Non-Small Company	149	72
175	10075	Minnesota Power Inc	Taconite Harbor Energy Center	MN	Non-Small Company	150	72
176	10686	Minnesota Power Inc	Rapids Energy Center	MN	Non-Small Company	151	72
177	1572	Mirant Mid-Atlantic LLC	Dickerson	MD	Non-Small Company	152	73
178	1573	Mirant Mid-Atlantic LLC	Morgantown Generating Plant	MD	Non-Small Company	153	73
179	2049	Mississippi Power Co	Jack Watson	MS	Non-Small Company	154	74
180	6073	Mississippi Power Co	Victor J. Daniel Jr	MS	Non-Small Company	155	74
181	3942	Monongahela Power Co	Albright Power Station	WV	Non-Small Company	156	75
182	3943	Monongahela Power Co	Fort Martin Power Station	WV	Non-Small Company	157	75
183	3945	Monongahela Power Co	Rivesville Power Station	WV	Non-Small Company	158	75
184	3946	Monongahela Power Co	Willow Island	WV	Non-Small Company	159	75

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Identity and Business Size of Parent Companies Which Own the 478 Potentially Affected Coal-Fired Electric Utility Plants (2013)

Item	Plant Code	Parent Company Owner Name	Electric Utility Plant Name (NAICS 22)	Plant Location State	Owner Business Size & Type of Business Entity	Size Type/ Count	Owner Entity Count
185	10743	Morgantown Energy Associates	Morgantown Energy Facility	WV	Non-Small Company	160	76
186	2549	NRG Huntley Operations Inc	CR Huntley Generating Station	NY	Non-Small Company	161	77
187	2324	Nevada Power Co	Reid Gardner	NV	Non-Small Company	162	78
188	2554	Dunkirk Power LLC	Dunkirk Generating Plant	NY	Non-Small Company	163	79
189	10380	North Carolina Power Holdings, LLC	Elizabethtown Power LLC	NC	Non-Small Company	164	80
190	995	Northern Indiana Pub Serv Co	Bailly	IN	Non-Small Company	165	81
191	997	Northern Indiana Pub Serv Co	Michigan City	IN	Non-Small Company	166	81
192	6085	Northern Indiana Pub Serv Co	R.M. Schahfer	IN	Non-Small Company	167	81
193	1904	Northern States Power Co - Minnesota	Black Dog	MN	Non-Small Company	168	82
194	1915	Northern States Power Co - Minnesota	Allen S King	MN	Non-Small Company	169	82
195	3982	Northern States Power Co - Minnesota	Bay Front	WI	Non-Small Company	170	82
196	6090	Northern States Power Co - Minnesota	Sherburne County	MN	Non-Small Company	171	82
197	50039	Northeastern Power Co	Kline Township Cogen Facility	PA	Non-Small Company	172	83
198	2872	Ohio Power Co	Muskingum River	OH	Non-Small Company	173	84
199	3947	Ohio Power Co	Kammer	WV	Non-Small Company	174	84
200	3948	Ohio Power Co	Mitchell	WV	Non-Small Company	175	84
201	8102	Ohio Power Co	General James M. Gavin	OH	Non-Small Company	176	84
202	2876	Ohio Valley Electric Corp	Kyger Creek	OH	Non-Small Company	177	85
203	2952	Oklahoma Gas & Electric Co	Muskogee	OK	Non-Small Company	178	86
204	6095	Oklahoma Gas & Electric Co	Sooner	OK	Non-Small Company	179	86
205	2836	Orion Power Midwest LP	Avon Lake	OH	Non-Small Company	180	87
206	2861	Orion Power Midwest LP	Niles Plant	OH	Non-Small Company	181	87
207	3098	Orion Power Midwest LP	Elrama Power Plant	PA	Non-Small Company	182	87
208	3138	Orion Power Midwest LP	New Castle Plant	PA	Non-Small Company	183	87
209	8226	Orion Power Midwest LP	Cheswick Power Plant	PA	Non-Small Company	184	87
210	1943	Otter Tail Power Co	Hoot Lake	MN	Non-Small Company	185	88
211	6098	Otter Tail Power Co	Big Stone	SD	Non-Small Company	186	88

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Item	Plant Code	Parent Company Owner Name	Electric Utility Plant Name (NAICS 22)	Plant Location State	Owner Business Size & Type of Business Entity	Size Type/ Count	Owner Entity Count
212	8222	Otter Tail Power Co	Coyote	ND	Non-Small Company	187	88
213	3644	PacifiCorp	Carbon Plant	UT	Non-Small Company	188	89
214	4158	PacifiCorp	Dave Johnston Plant	WY	Non-Small Company	189	89
215	4162	PacifiCorp	Naughton Plant	WY	Non-Small Company	190	89
216	6101	PacifiCorp	Wyodak Plant	WY	Non-Small Company	191	89
217	6165	PacifiCorp	Hunter Plant	UT	Non-Small Company	192	89
218	8066	PacifiCorp	Jim Bridger Plant Units 1-4	WY	Non-Small Company	193	89
219	8069	PacifiCorp	Huntington Plant	UT	Non-Small Company	194	89
220	2403	PSEG Fossil LLC	PSEG Hudson Generating Station	NJ	Non-Small Company	195	90
221	2408	PSEG Fossil LLC	PSEG Mercer Generating Station	NJ	Non-Small Company	196	90
222	6106	Portland General Electric Co	Boardman	OR	Non-Small Company	197	91
223	2187	PPL Montana LLC	JE Corette Plant	MT	Non-Small Company	198	92
224	6076	PPL Montana LLC	Colstrip	MT	Non-Small Company	199	92
225	568	PSEG Power Connecticut LLC	Bridgeport Station	CT	Non-Small Company	200	93
226	465	Public Service Co of Colorado	Arapahoe	CO	Non-Small Company	201	94
227	469	Public Service Co of Colorado	Cherokee	CO	Non-Small Company	202	94
228	470	Public Service Co of Colorado	Comanche	CO	Non-Small Company	203	94
229	477	Public Service Co of Colorado	Valmont	CO	Non-Small Company	204	94
230	525	Public Service Co of Colorado	Hayden	CO	Non-Small Company	205	94
231	6248	Public Service Co of Colorado	Pawnee	CO	Non-Small Company	206	94
232	1001	Duke Energy Indiana Inc	Cayuga	IN	Non-Small Company	207	95
233	1004	Duke Energy Indiana Inc	Edwardsport	IN	Non-Small Company	208	95
234	1008	Duke Energy Indiana Inc	R. Gallagher	IN	Non-Small Company	209	95
235	1010	Duke Energy Indiana Inc	Wabash River	IN	Non-Small Company	210	95
236	6113	Duke Energy Indiana Inc	Gibson	IN	Non-Small Company	211	95
237	2364	Public Service Co of NH	Merrimack Station	NH	Non-Small Company	212	96
238	2367	Public Service Co of NH	SCHILLER	NH	Non-Small Company	213	96
239	2451	Public Service Co of NM	San Juan	NM	Non-Small Company	214	97
240	127	Public Service Co of Oklahoma	Oklunion	TX	Non-Small Company	215	98
241	2963	Public Service Co of Oklahoma	Northeastern	OK	Non-Small Company	216	98
242	3149	PPL Montour LLC	PPL Montour	PA	Non-Small Company	217	99

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Item	Plant Code	Parent Company Owner Name	Electric Utility Plant Name (NAICS 22)	Plant Location State	Owner Business Size & Type of Business Entity	Size Type/ Count	Owner Entity Count
243	3140	PPL Brunner Island LLC	PPL Brunner Island	PA	Non-Small Company	218	100
244	3118	RRI Energy NE Management Co	Conemaugh	PA	Non-Small Company	219	101
245	3136	RRI Energy NE Management Co	Keystone	PA	Non-Small Company	220	101
246	8224	Sierra Pacific Power Co	North Valmy	NV	Non-Small Company	221	102
247	3113	RRI Energy Mid-Atlantic PH LLC	Portland	PA	Non-Small Company	222	103
248	3115	RRI Energy Mid-Atlantic PH LLC	Titus	PA	Non-Small Company	223	103
249	3131	RRI Energy Mid-Atlantic PH LLC	Shawville	PA	Non-Small Company	224	103
250	3280	South Carolina Electric&Gas Co	Canadys Steam	SC	Non-Small Company	225	104
251	3287	South Carolina Electric&Gas Co	McMeekin	SC	Non-Small Company	226	104
252	3295	South Carolina Electric&Gas Co	Urquhart	SC	Non-Small Company	227	104
253	3297	South Carolina Electric&Gas Co	Wateree	SC	Non-Small Company	228	104
254	7210	South Carolina Electric&Gas Co	Cope	SC	Non-Small Company	229	104
255	3298	South Carolina Genertg Co, Inc	Williams	SC	Non-Small Company	230	105
256	1012	Southern Indiana Gas & Elec Co	F. B. Culley	IN	Non-Small Company	231	106
257	6137	Southern Indiana Gas & Elec Co	A. B. Brown Generating Station	IN	Non-Small Company	232	106
258	6138	Southwestern Electric Power Co	Flint Creek	AR	Non-Small Company	233	107
259	6139	Southwestern Electric Power Co	Welsh	TX	Non-Small Company	234	107
260	7902	Southwestern Electric Power Co	Pirkey	TX	Non-Small Company	235	107
261	56564	Southwestern Electric Power Co	John W Turk Jr Power Plant	AR	Non-Small Company	236	107
262	6193	Southwestern Public Service Co	Harrington	TX	Non-Small Company	237	108
263	6194	Southwestern Public Service Co	Tolk	TX	Non-Small Company	238	108
264	981	State Line Energy LLC	State Line	IN	Non-Small Company	239	109
265	50835	TES Filer City Station LP	TES Filer City Station	MI	Non-Small Company	240	110
266	645	Tampa Electric Co	Big Bend	FL	Non-Small Company	241	111
267	7242	Tampa Electric Co	Polk	FL	Non-Small Company	242	111
268	3845	TransAlta Centralia Gen LLC	TransAlta Centralia Generation	WA	Non-Small Company	243	112
269	55245	Trigen-Cinergy Sol-Tuscola LLC	Tuscola Station	IL	Non-Small Company	244	113
270	10003	Colorado Energy Nations Company LLLP	Colorado Energy Nations Company	CO	Non-Small Company	245	114
271	50651	Syracuse Energy Corp	Trigen Syracuse Energy	NY	Non-Small Company	246	115
272	3497	TXU Generation Co LP	Big Brown	TX	Non-Small Company	247	116

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Item	Plant Code	Parent Company Owner Name	Electric Utility Plant Name (NAICS 22)	Plant Location State	Owner Business Size & Type of Business Entity	Size Type/ Count	Owner Entity Count
273	6146	TXU Generation Co LP	Martin Lake	TX	Non-Small Company	248	116
274	6147	TXU Generation Co LP	Monticello	TX	Non-Small Company	249	116
275	6648	TXU Generation Co LP	Sadow No 4	TX	Non-Small Company	250	116
276	2103	Union Electric Co	Labadie	MO	Non-Small Company	251	117
277	2104	Union Electric Co	Meramec	MO	Non-Small Company	252	117
278	2107	Union Electric Co	Sioux	MO	Non-Small Company	253	117
279	6155	Union Electric Co	Rush Island	MO	Non-Small Company	254	117
280	3325	Black Hills Power Inc	Ben French	SD	Non-Small Company	255	118
281	4150	Black Hills Power Inc	Neil Simpson	WY	Non-Small Company	256	118
282	7504	Black Hills Power Inc	Neil Simpson II	WY	Non-Small Company	257	118
283	55479	Black Hills Power Inc	Wygen 1	WY	Non-Small Company	258	118
284	56319	Black Hills Power Inc	Wygen 2	WY	Non-Small Company	259	118
285	56596	Black Hills Power Inc	Wygen III	WY	Non-Small Company	260	118
286	3796	Virginia Electric & Power Co	Bremo Bluff	VA	Non-Small Company	261	119
287	3797	Virginia Electric & Power Co	Chesterfield	VA	Non-Small Company	262	119
288	3803	Virginia Electric & Power Co	Chesapeake Energy Center	VA	Non-Small Company	263	119
289	3809	Virginia Electric & Power Co	Yorktown	VA	Non-Small Company	264	119
290	3954	Virginia Electric & Power Co	Mt. Storm	WV	Non-Small Company	265	119
291	7213	Virginia Electric & Power Co	Clover	VA	Non-Small Company	266	119
292	7537	Virginia Electric & Power Co	North Branch	WV	Non-Small Company	267	119
293	10771	Virginia Electric & Power Co	Hopewell	VA	Non-Small Company	268	119
294	10774	Virginia Electric & Power Co	Southampton Power Station	VA	Non-Small Company	269	119
295	52007	Virginia Electric & Power Co	Mecklenburg Power Station	VA	Non-Small Company	270	119
296	56808	Virginia Electric & Power Co	Virginia City Hybrid Energy Center	VA	Non-Small Company	271	119
297	50879	Wheelabrator Environmental Systems	Wheelabrator Frackville Energy Co.	PA	Non-Small Company	272	120
298	1769	Wisconsin Electric Power Co	Presque Isle	MI	Non-Small Company	273	121
299	4041	Wisconsin Electric Power Co	South Oak Creek	WI	Non-Small Company	274	121
300	4042	Wisconsin Electric Power Co	Valley	WI	Non-Small Company	275	121
301	6170	Wisconsin Electric Power Co	Pleasant Prairie	WI	Non-Small Company	276	121
302	7549	Wisconsin Electric Power Co	Milwaukee County	WI	Non-Small Company	277	121

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Item	Plant Code	Parent Company Owner Name	Electric Utility Plant Name (NAICS 22)	Plant Location State	Owner Business Size & Type of Business Entity	Size Type/ Count	Owner Entity Count
303	4050	Wisconsin Power & Light Co	Edgewater	WI	Non-Small Company	278	122
304	4054	Wisconsin Power & Light Co	Nelson Dewey	WI	Non-Small Company	279	122
305	4057	Wisconsin Power & Light Co	WI Power & Light Co -Rock River Generating	WI	Non-Small Company	280	122
306	8023	Wisconsin Power & Light Co	Columbia	WI	Non-Small Company	281	122
307	4072	Wisconsin Public Service Corp	Pulliam	WI	Non-Small Company	282	123
308	4078	Wisconsin Public Service Corp	Weston	WI	Non-Small Company	283	123
309	50611	WPS Power Developement	WPS Westwood Generation, LLC	PA	Non-Small Company	284	124
310	50951	Sunnyside Cogeneration Assoc	Sunnyside Cogen Associates	UT	Non-Small Company	285	125
311	1353	Kentucky Power Co	Big Sandy	KY	Non-Small Company	286	126
312	2535	AES Cayuga LLC	AES Cayuga, LLC	NY	Non-Small Company	287	127
313	6082	AES Somerset LLC	AES Somerset LLC	NY	Non-Small Company	288	128
314	1250	Westar Energy Inc	Lawrence Energy Center	KS	Non-Small Company	289	129
315	1252	Westar Energy Inc	Tecumseh Energy Center	KS	Non-Small Company	290	129
316	6068	Westar Energy Inc	Jeffrey Energy Center	KS	Non-Small Company	291	129
317	1570	Allegheny Energy Supply Co LLC	R. Paul Smith Power Station	MD	Non-Small Company	292	130
318	3178	Allegheny Energy Supply Co LLC	Armstrong Power Station	PA	Non-Small Company	293	130
319	3179	Allegheny Energy Supply Co LLC	Hatfield's Ferry Power Station	PA	Non-Small Company	294	130
320	3181	Allegheny Energy Supply Co LLC	Mitchell Power Station	PA	Non-Small Company	295	130
321	3944	Allegheny Energy Supply Co LLC	Harrison Power Station	WV	Non-Small Company	296	130
322	6004	Allegheny Energy Supply Co LLC	Pleasants Power Station	WV	Non-Small Company	297	130
323	126	Tucson Electric Power Co	H Wilson Sundt Generating Station	AZ	Non-Small Company	298	131
324	8223	Tucson Electric Power Co	Springerville	AZ	Non-Small Company	299	131
325	87	Tri-State G & T Assn, Inc	Escalante	NM	Non-Small Company	300	132
326	527	Tri-State G & T Assn, Inc	Nucla	CO	Non-Small Company	301	132
327	6021	Tri-State G & T Assn, Inc	Craig	CO	Non-Small Company	302	132
328	50407	DTE Energy Services	Mobile Energy Services LLC	AL	Non-Small Company	303	133
329	856	Ameren Energy Resources Generating Co.	ED Edwards	IL	Non-Small Company	304	134
330	6016	Ameren Energy Resources Generating Co.	Duck Creek	IL	Non-Small Company	305	134

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Item	Plant Code	Parent Company Owner Name	Electric Utility Plant Name (NAICS 22)	Plant Location State	Owner Business Size & Type of Business Entity	Size Type/ Count	Owner Entity Count
331	56224	Newmont Nevada Energy Investment, LLC	TS Power Plant	NV	Non-Small Company	306	135
332	1619	Dominion Energy New England, LLC	Brayton Point	MA	Non-Small Company	307	136
333	1626	Dominion Energy New England, LLC	Salem Harbor	MA	Non-Small Company	308	136
334	10495	NewPage Corporation	Rumford Cogeneration	ME	Non-Small Company	309	137
335	3130	RRI Energy Wholesale Generation LLC	Seward	PA	Non-Small Company	310	138
336	298	NRG Texas Power LLC	Limestone	TX	Non-Small Company	311	139
337	3470	NRG Texas Power LLC	W. A. Parish	TX	Non-Small Company	312	139
338	1606	FirstLight Power Resources Services LLC	Mount Tom	MA	Non-Small Company	313	140
339	6018	Duke Energy Kentucky Inc	East Bend Station	KY	Non-Small Company	314	141
340	54035	Westmoreland Partners	Roanoke Valley I	NC	Non-Small Company	315	142
341	54755	Westmoreland Partners	Roanoke Valley II	NC	Non-Small Company	316	142
342	56671	GenPower	Longview Power LLC	WV	Non-Small Company	317	143
343	1393	Entergy Gulf States Louisiana LLC	RS Nelson	LA	Non-Small Company	318	144
344	56848	SunCoke Energy, Inc.	Haverhill North Cogeneration Facility	OH	Non-Small Company	319	145
345	462	Black Hills/Colorado Elec.Utility Co. LP	W N Clark	CO	Non-Small Company	320	146
346	7652	Savannah River Nuclear Solutions LLC	US DOE Savannah River Site (D Area)	SC	Non-Small Company	321	147
347	2094	KCP&L Greater Missouri Operations Co	Sibley	MO	Non-Small Company	322	148
348	2098	KCP&L Greater Missouri Operations Co	Lake Road	MO	Non-Small Company	323	148
349	10071	Portsmouth Operating Services LLC	Cogentrix Virginia Leasing Corporation	VA	Non-Small Company	324	149
350	6178	Coletto Creek Power LP	Coletto Creek	TX	Non-Small Company	325	150
351	7030	Optim Energy LLC	Twin Oaks Power One	TX	Non-Small Company	326	151
352	2817	Basin Electric Power Coop	Leland Olds	ND	Non-Small Coop	1	152

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Item	Plant Code	Parent Company Owner Name	Electric Utility Plant Name (NAICS 22)	Plant Location State	Owner Business Size & Type of Business Entity	Size Type/ Count	Owner Entity Count
353	6204	Basin Electric Power Coop	Laramie River Station	WY	Non-Small Coop	2	152
354	6469	Basin Electric Power Coop	Antelope Valley Station	ND	Non-Small Coop	3	152
355	56609	Basin Electric Power Coop	Dry Fork Station	WY	Non-Small Coop	4	152
356	2824	Great River Energy	Stanton	ND	Non-Small Coop	5	153
357	6030	Great River Energy	Coal Creek	ND	Non-Small Coop	6	153
358	47	Tennessee Valley Authority	Colbert	AL	Non-Small Federal	1	154
359	50	Tennessee Valley Authority	Widows Creek	AL	Non-Small Federal	2	154
360	1378	Tennessee Valley Authority	Paradise	KY	Non-Small Federal	3	154
361	1379	Tennessee Valley Authority	Shawnee	KY	Non-Small Federal	4	154
362	3393	Tennessee Valley Authority	Allen Steam Plant	TN	Non-Small Federal	5	154
363	3396	Tennessee Valley Authority	Bull Run	TN	Non-Small Federal	6	154
364	3399	Tennessee Valley Authority	Cumberland	TN	Non-Small Federal	7	154
365	3403	Tennessee Valley Authority	Gallatin	TN	Non-Small Federal	8	154
366	3405	Tennessee Valley Authority	John Sevier	TN	Non-Small Federal	9	154
367	3406	Tennessee Valley Authority	Johnsonville	TN	Non-Small Federal	10	154
368	3407	Tennessee Valley Authority	Kingston	TN	Non-Small Federal	11	154
369	165	Grand River Dam Authority	GRDA	OK	Non-Small State	1	155
370	6179	Lower Colorado River Authority	Fayette Power Project	TX	Non-Small State	2	156
371	2277	Nebraska Public Power District	Sheldon Station	NE	Non-Small State	3	157
372	6077	Nebraska Public Power District	Gerald Gentleman	NE	Non-Small State	4	157
373	2291	Omaha Public Power District	North Omaha	NE	Non-Small State	5	158
374	6096	Omaha Public Power District	Nebraska City	NE	Non-Small State	6	158
375	6761	Platte River Power Authority	Rawhide	CO	Non-Small State	7	159
376	4941	Salt River Project	Navajo Generating Station	AZ	Non-Small State	8	160
377	6177	Salt River Project	Coronado Generating Station	AZ	Non-Small State	9	160
378	130	South Carolina Pub Serv Auth	Cross	SC	Non-Small State	10	161
379	3319	South Carolina Pub Serv Auth	Jefferies	SC	Non-Small State	11	161
380	6249	South Carolina Pub Serv Auth	Winyah	SC	Non-Small State	12	161
381	1961	Austin City of	Austin Northeast	MN	Small City	1	162
382	1131	Cedar Falls Utilities	Streeter Station	IA	Small City	2	163
383	1024	Crawfordsville Elec, Lgt & Pwr	Crawfordsville	IN	Small City	3	164

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Item	Plant Code	Parent Company Owner Name	Electric Utility Plant Name (NAICS 22)	Plant Location State	Owner Business Size & Type of Business Entity	Size Type/ Count	Owner Entity Count
384	2914	City of Dover	Dover	OH	Small City	4	165
385	2240	Fremont City of	Lon Wright	NE	Small City	5	166
386	1825	City of Grand Haven	Grand Haven City of J.B. Sims	MI	Small City	6	167
387	2062	Greenwood Utilities Comm	Henderson	MS	Small City	7	168
388	60	Hastings City of	Whelan Energy Center Unit 1 (WEC1)	NE	Small City	8	169
389	1979	Hibbing Public Utilities Comm	Hibbing	MN	Small City	9	170
390	1830	City of Holland	James De Young	MI	Small City	10	171
391	2682	Jamestown Board of Public Util	S A Carlson	NY	Small City	11	172
392	2682	City of Jasper	Jasper 2	IN	Small City	12	173
393	508	City of Lamar	Lamar Plant	CO	Small City	13	174
394	1032	City of Logansport	Logansport	IN	Small City	14	175
395	4125	Manitowoc Public Utilities	Manitowoc	WI	Small City	15	176
396	1843	City of Marquette	Shiras	MI	Small City	16	177
397	2144	City of Marshall	Marshall	MO	Small City	17	178
398	4259	Michigan South Central Pwr Agy	Endicott Station	MI	Small City	18	179
399	1167	Board of Water Electric & Communications	Muscatine #1	IA	Small City	19	180
400	2935	City of Orrville	Orrville	OH	Small City	20	181
401	2936	City of Painesville	Painesville	OH	Small City	21	182
402	1175	Pella City of	Pella	IA	Small City	22	183
403	1037	Peru City of	Peru	IN	Small City	23	184
404	2468	Raton Public Service Company	Raton	NM	Small City	24	185
405	1040	City of Richmond	Whitewater Valley	IN	Small City	25	186
406	2943	City of Shelby	Shelby Municipal Light Plant	OH	Small City	26	187
407	6768	City of Sikeston	Sikeston Power Station	MO	Small City	27	188
408	6136	Texas Municipal Power Agency	Gibbons Creek Steam Electric Station	TX	Small City	28	189
409	2018	City of Virginia	Virginia	MN	Small City	29	190
410	2022	Willmar Municipal Utilities	Willmar	MN	Small City	30	191
411	1866	Wyandotte Municipal Serv Comm	Wyandotte	MI	Small City	21	192
412	59	Grand Island City of	Platte	NE	Small City	32	193
413	10640	Air Products Energy Enterprises	Stockton Cogen	CA	Small Company	1	194

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Item	Plant Code	Parent Company Owner Name	Electric Utility Plant Name (NAICS 22)	Plant Location State	Owner Business Size & Type of Business Entity	Size Type/ Count	Owner Entity Count
		LP					
414	79	Aurora Energy LLC	Aurora Energy LLC Chena	AK	Small Company	2	195
415	56068	Wisconsin Electric Power Co	Elm Road Generating Station	WI	Small Company	3	196
416	1381	Big Rivers Electric Corp	Kenneth C Coleman	KY	Small Company	4	197
417	1382	Big Rivers Electric Corp	HMP&L Station Two Henderson	KY	Small Company	5	197
418	1383	Big Rivers Electric Corp	Robert A Reid	KY	Small Company	6	197
419	6639	Big Rivers Electric Corp	R D Green	KY	Small Company	7	197
420	6823	Big Rivers Electric Corp	D B Wilson	KY	Small Company	8	197
421	10464	Black River Generation LLC	Black River Generation	NY	Small Company	9	198
422	10148	White Pine Electric Power LLC	White Pine Electric Power	MI	Small Company	10	199
423	10641	Cambria CoGen Co	Cambria Cogen	PA	Small Company	11	200
424	2828	Cardinal Operating Co	Cardinal	OH	Small Company	12	201
425	10784	Colstrip Energy LP	Colstrip Energy LP	MT	Small Company	13	202
426	1239	Empire District Electric Co	Riverton	KS	Small Company	14	203
427	2076	Empire District Electric Co	Asbury	MO	Small Company	15	203
428	10113	Gilberton Power Co	John B Rich Memorial Power Station	PA	Small Company	16	204
429	6288	Golden Valley Elec Assn Inc	Healy	AK	Small Company	17	205
430	1043	Hoosier Energy R E C, Inc	Frank E. Ratts	IN	Small Company	18	206
431	6213	Hoosier Energy R E C, Inc	Merom	IN	Small Company	19	206
432	10143	Inter-Power/AhlCon Partners, L.P.	Colver Power Project	PA	Small Company	20	207
433	10377	James River Cogeneration Co	James River Cogeneration Co	VA	Small Company	21	208
434	50776	Panther Creek Partners	PANTHER CREEK ENERGY FACILITY	PA	Small Company	22	209
435	10043	US Operating Services Company	Logan Generating Plant	NJ	Small Company	23	210
436	10566	US Operating Services Company	Chambers Cogeneration LP	NJ	Small Company	24	210
437	10672	US Operating Services Company	Cedar Bay Generating Company L.P.	FL	Small Company	25	210
438	50888	US Operating Services Company	Northampton Generating Company, L.P.	PA	Small Company	26	210
439	50974	US Operating Services Company	Scrubgrass Generating Company L.P.	PA	Small Company	27	210
440	50976	US Operating Services Company	INDIANTOWN COGENERATION L.P.	FL	Small Company	28	210
441	55856	Prairie State Generating Co LLC	Prairie State Generatng Station	IL	Small Company	29	211
442	10769	Rio Bravo Poso	Rio Bravo Poso	CA	Small Company	30	212
443	10768	Rio Bravo Jasmin	Rio Bravo Jasmin	CA	Small Company	31	213

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Item	Plant Code	Parent Company Owner Name	Electric Utility Plant Name (NAICS 22)	Plant Location State	Owner Business Size & Type of Business Entity	Size Type/ Count	Owner Entity Count
444	55749	Rocky Mountain Power Inc	Hardin Generator Project	MT	Small Company	32	214
445	54634	Schuylkill Energy Resource Inc	St. Nicholas Cogen Project	PA	Small Company	33	215
446	108	Sunflower Electric Power Corp	HOLCOMB	KS	Small Company	34	216
447	1771	Upper Peninsula Power Co	Escanaba	MI	Small Company	35	217
448	3152	Sunbury Generation LP	Sunbury Generation LP	PA	Small Company	36	218
449	10343	Mount Carmel Cogen Inc	Foster Wheeler Mt Carmel Cogen	PA	Small Company	37	219
450	10381	Carlyle/Riverstone Renewable Energy	Coastal Carolina Clean Power	NC	Small Company	38	220
451	10384	Edgecombe Operating Services LLC	Edgecombe Genco, LLC	NC	Small Company	39	221
452	54081	Spruance Operating Services LLC	Spruance Genco, LLC	VA	Small Company	40	222
453	2378	RC Cape May Holdings LLC	BL England	NJ	Small Company	41	223
454	50202	Niagara Generation LLC	WPS Power Niagara	NY	Small Company	42	224
455	56456	Plum Point Energy Associates LLC	Plum Point Energy Station	AR	Small Company	43	225
456	10378	CPI USA NC LLC	Primary Energy Southport	NC	Small Company	44	226
457	10379	CPI USA NC LLC	Primary Energy Roxboro	NC	Small Company	45	226
458	56	PowerSouth Energy Cooperative	Charles R. Lowman	AL	Small Cooperative	1	227
459	160	Arizona Electric Pwr Coop Inc	Apache Station	AZ	Small Cooperative	2	228
460	2167	Associated Electric Coop, Inc	New Madrid	MO	Small Cooperative	3	229
461	2168	Associated Electric Coop, Inc	Thomas Hill	MO	Small Cooperative	4	229
462	2169	Central Electric Power Coop	Chamois Power Plant	MO	Small Cooperative	5	230
463	1217	Corn Belt Power Coop	Earl F Wisdom	IA	Small Cooperative	6	231
464	4140	Dairyland Power Coop	Alma	WI	Small Cooperative	7	232
465	4143	Dairyland Power Coop	Genoa	WI	Small Cooperative	8	232
466	4271	Dairyland Power Coop	John P. Madgett	WI	Small Cooperative	9	232
467	1384	East Kentucky Power Coop, Inc	Cooper Station.	KY	Small Cooperative	10	233
468	1385	East Kentucky Power Coop, Inc	Dale Station	KY	Small Cooperative	11	233
469	6041	East Kentucky Power Coop, Inc	H L Spurlock Station	KY	Small Cooperative	12	233
470	2823	Minnkota Power Coop, Inc	Milton R. Young Station	ND	Small Cooperative	13	234
471	6183	San Miguel Electric Coop, Inc	San Miguel	TX	Small Cooperative	14	235
472	6061	South Mississippi El Pwr Assn	South Mississippi El Pwr Assn	MS	Small Cooperative	15	236

Exhibit C-1**Identity and Business Size of Parent Companies Which Own the 478 Potentially Affected Coal-Fired Electric Utility Plants (2013)**

Item	Plant Code	Parent Company Owner Name	Electric Utility Plant Name (NAICS 22)	Plant Location State	Owner Business Size & Type of Business Entity	Size Type/ Count	Owner Entity Count
473	976	Southern Illinois Power Coop	Marion Generating Station	IL	Small Cooperative	16	237
474	6772	Western Farmers Elec Coop, Inc	Hugo	OK	Small Cooperative	17	238
475	136	Seminole Electric Cooperative Inc	Seminole Generating Station	FL	Small Cooperative	18	239
476	7790	Deseret Generation & Tran Coop	Bonanza Power Plant	UT	Small Cooperative	19	240
477	6238	Prairie Power, Inc	Pearl Station	IL	Small Cooperative	20	241
478	753	Crisp County Power Comm	Crisp Plant	GA	Small County	1	242

Exhibit C-2

Revenues and Costs Used for SBREFA and UMRA/Federalism Calculations

Entity ID	Entity Size	EIA Nameplate Capacity	Estimated Annual Million MWhs	Average Statewide Price (\$2013)	Annual Revenue (\$M)	Annual Cost (\$M)	Cost as % of Rev.
1	Non-Small City	108.8	0.95	\$0.0853	\$70.51	\$0.33	0.47%
2	Non-Small City	535.6	4.70	\$0.1036	\$421.43	\$1.28	0.30%
3	Non-Small City	100.6	0.88	\$0.1023	\$78.40	\$0.41	0.52%
4	Non-Small City	471.0	4.13	\$0.1111	\$396.80	\$0.47	0.12%
5	Non-Small City	138.1	1.11	\$0.0973	\$93.79	\$0.00	0.00%
6	Non-Small City	222.0	1.41	\$0.1023	\$124.97	\$1.77	1.41%
7	Non-Small City	2765.1	24.22	\$0.1111	\$2,329.41	\$0.11	0.00%
8	Non-Small City	743.4	6.51	\$0.0958	\$540.12	\$0.26	0.05%
9	Non-Small City	993.9	8.71	\$0.1111	\$837.41	\$0.11	0.01%
10	Non-Small City	1640.0	14.37	\$0.0770	\$958.56	\$2.26	0.24%
11	Non-Small City	445.3	3.90	\$0.0768	\$259.41	\$0.96	0.37%
12	Non-Small City	929.0	11.06	\$0.1111	\$1,063.19	\$0.15	0.01%
13	Non-Small City	99.0	0.87	\$0.0934	\$70.14	\$0.00	0.00%
14	Non-Small City	1498.0	20.81	\$0.0993	\$1,789.44	\$2.70	0.15%
15	Non-Small City	387.7	5.85	\$0.0953	\$483.03	\$1.09	0.23%
16	Non-Small City	753.5	9.22	\$0.1023	\$817.38	\$2.05	0.25%
17	Non-Small City	54.0	0.60	\$0.1543	\$79.59	\$0.00	0.00%
18	Non-Small City	529.7	4.64	\$0.1138	\$457.52	\$0.35	0.08%
19	Non-Small Company	350.0	3.07	\$0.0860	\$228.29	\$0.00	0.00%
20	Non-Small Company	162.5	0.98	\$0.1742	\$148.00	\$1.28	0.86%
21	Non-Small Company	229.0	2.01	\$0.1240	\$215.50	\$0.00	0.00%
22	Non-Small Company	108.0	0.95	\$0.1529	\$125.25	\$0.41	0.32%
23	Non-Small Company	149.0	1.31	\$0.1100	\$124.38	\$0.00	0.00%
24	Non-Small Company	203.0	1.78	\$0.3442	\$530.10	\$0.00	0.00%
25	Non-Small Company	10370.5	92.34	\$0.1000	\$7,995.59	\$17.43	0.22%
26	Non-Small Company	777.6	7.01	\$0.0838	\$508.87	\$1.26	0.25%
27	Non-Small Company	2240.2	19.62	\$0.0953	\$1,619.74	\$11.75	0.73%
28	Non-Small Company	95.7	0.84	\$0.0823	\$59.95	\$4.20	7.01%
29	Non-Small Company	6827.3	55.47	\$0.0965	\$4,067.73	\$10.97	0.27%
30	Non-Small Company	3398.4	29.78	\$0.1072	\$2,636.45	\$18.72	0.71%
31	Non-Small Company	3400.0	31.54	\$0.0822	\$2,245.54	\$0.97	0.04%
32	Non-Small Company	0.0	15.72	\$0.0993	\$1,351.87	\$3.63	0.27%
33	Non-Small Company	0.0	3.98	\$0.1075	\$370.24	\$0.00	0.00%
34	Non-Small Company	258.3	2.26	\$0.0965	\$188.94	\$0.00	0.00%
35	Non-Small Company	6824.4	48.20	\$0.0916	\$3,821.95	\$10.12	0.26%
36	Non-Small Company	1724.2	21.27	\$0.0833	\$1,535.06	\$1.17	0.08%
37	Non-Small Company	4202.5	35.81	\$0.0973	\$3,018.99	\$10.65	0.35%
38	Non-Small Company	513.7	4.50	\$0.0918	\$357.82	\$0.40	0.11%
39	Non-Small Company	20.0	0.20	\$0.0838	\$14.63	\$0.00	0.00%
40	Non-Small Company	1997.0	17.49	\$0.0973	\$1,474.79	\$2.85	0.19%
41	Non-Small Company	36.2	0.32	\$0.1100	\$30.05	\$0.00	0.00%
42	Non-Small Company	2844.3	24.91	\$0.1240	\$2,676.29	\$0.38	0.01%

Exhibit C-2

Revenues and Costs Used for SBREFA and UMRA/Federalism Calculations

Entity ID	Entity Size	EIA Nameplate Capacity	Estimated Annual Million MWhs	Average Statewide Price (\$2013)	Annual Revenue (\$M)	Annual Cost (\$M)	Cost as % of Rev.
43	Non-Small Company	4765.6	39.60	\$0.1138	\$3,902.77	\$10.54	0.27%
44	Non-Small Company	3587.5	31.43	\$0.0973	\$2,649.74	\$5.42	0.20%
45	Non-Small Company	8372.9	73.35	\$0.1138	\$7,228.02	\$12.83	0.18%
46	Non-Small Company	1319.0	11.55	\$0.0953	\$953.77	\$2.48	0.26%
47	Non-Small Company	7604.7	75.87	\$0.0916	\$6,022.41	\$10.88	0.18%
48	Non-Small Company	3568.5	27.93	\$0.0953	\$2,305.24	\$5.08	0.22%
49	Non-Small Company	57.6	0.51	\$0.1100	\$48.42	\$0.00	0.00%
50	Non-Small Company	1099.8	9.64	\$0.0953	\$795.41	\$2.96	0.37%
51	Non-Small Company	3333.1	21.40	\$0.1111	\$2,058.13	\$4.58	0.22%
52	Non-Small Company	7669.6	59.40	\$0.0973	\$5,271.63	\$57.87	1.10%
53	Non-Small Company	15558.7	152.76	\$0.1088	\$14,395.42	\$29.30	0.20%
54	Non-Small Company	2234.6	19.58	\$0.1111	\$1,882.90	\$3.90	0.21%
55	Non-Small Company	82.0	0.70	\$0.1529	\$92.78	\$0.00	0.00%
56	Non-Small Company	118.0	1.03	\$0.1189	\$106.41	\$0.48	0.45%
57	Non-Small Company	46.1	0.40	\$0.3442	\$120.12	\$0.00	0.00%
58	Non-Small Company	1303.2	11.42	\$0.0838	\$829.45	\$5.16	0.62%
59	Non-Small Company	3462.2	32.84	\$0.0838	\$2,384.67	\$15.34	0.64%
60	Non-Small Company	3700.1	32.41	\$0.0838	\$2,353.50	\$8.10	0.34%
61	Non-Small Company	799.4	5.62	\$0.1189	\$578.03	\$1.34	0.23%
62	Non-Small Company	2077.1	17.09	\$0.0853	\$1,262.03	\$6.56	0.52%
63	Non-Small Company	3939.1	42.50	\$0.0958	\$3,688.52	\$2.26	0.06%
64	Non-Small Company	4209.5	37.04	\$0.0768	\$2,464.70	\$28.39	1.15%
65	Non-Small Company	4138.2	43.55	\$0.0768	\$2,898.41	\$17.74	0.61%
66	Non-Small Company	1871.0	16.67	\$0.0833	\$1,203.14	\$0.37	0.03%
67	Non-Small Company	165.0	1.45	\$0.0814	\$103.29	\$0.94	0.91%
68	Non-Small Company	4417.8	38.70	\$0.0853	\$2,857.84	\$5.85	0.20%
69	Non-Small Company	8800.7	73.85	\$0.0953	\$6,320.39	\$4.76	0.08%
70	Non-Small Company	514.0	4.50	\$0.0965	\$376.42	\$0.00	0.00%
71	Non-Small Company	2647.0	23.19	\$0.1240	\$2,490.91	\$0.29	0.01%
72	Non-Small Company	1542.5	13.51	\$0.0934	\$1,092.46	\$2.13	0.19%
73	Non-Small Company	2478.0	21.71	\$0.1240	\$2,331.87	\$0.49	0.02%
74	Non-Small Company	3444.5	30.18	\$0.0918	\$2,398.23	\$1.54	0.06%
75	Non-Small Company	1753.1	15.35	\$0.0823	\$1,094.61	\$1.33	0.12%
76	Non-Small Company	68.9	0.60	\$0.0823	\$43.09	\$0.00	0.00%
77	Non-Small Company	436.0	3.50	\$0.1742	\$528.58	\$0.78	0.15%
78	Non-Small Company	636.8	5.58	\$0.1020	\$492.99	\$1.22	0.25%
79	Non-Small Company	627.2	1.68	\$0.1742	\$253.72	\$0.68	0.27%
80	Non-Small Company	34.7	0.30	\$0.0916	\$24.10	\$0.00	0.00%
81	Non-Small Company	3522.4	29.63	\$0.0838	\$2,151.23	\$5.67	0.26%
82	Non-Small Company	3714.5	32.73	\$0.0934	\$2,653.34	\$4.33	0.16%
83	Non-Small Company	57.5	0.52	\$0.1100	\$49.25	\$0.00	0.00%
84	Non-Small Company	6474.5	56.71	\$0.0973	\$4,513.80	\$14.99	0.33%

Exhibit C-2

Revenues and Costs Used for SBREFA and UMRA/Federalism Calculations

Entity ID	Entity Size	EIA Nameplate Capacity	Estimated Annual Million MWhs	Average Statewide Price (\$2013)	Annual Revenue (\$M)	Annual Cost (\$M)	Cost as % of Rev.
85	Non-Small Company	1086.5	9.51	\$0.0973	\$802.01	\$1.82	0.23%
86	Non-Small Company	3027.0	25.00	\$0.0860	\$1,861.53	\$1.34	0.07%
87	Non-Small Company	2589.0	20.32	\$0.0973	\$1,857.52	\$2.51	0.13%
88	Non-Small Company	1037.7	9.09	\$0.0934	\$664.23	\$1.79	0.27%
89	Non-Small Company	6860.4	60.10	\$0.0770	\$3,663.76	\$16.78	0.46%
90	Non-Small Company	1882.4	12.51	\$0.1543	\$1,671.49	\$1.48	0.09%
91	Non-Small Company	601.0	5.62	\$0.0815	\$396.99	\$0.48	0.12%
92	Non-Small Company	2444.8	21.42	\$0.0851	\$1,577.81	\$11.89	0.75%
93	Non-Small Company	581.6	5.10	\$0.1639	\$723.82	\$0.00	0.00%
94	Non-Small Company	2997.8	31.36	\$0.1036	\$2,814.76	\$8.37	0.30%
95	Non-Small Company	6449.9	51.20	\$0.0838	\$3,718.02	\$12.89	0.35%
96	Non-Small Company	667.6	5.84	\$0.1491	\$754.54	\$0.72	0.10%
97	Non-Small Company	1848.0	16.19	\$0.0998	\$1,398.91	\$0.00	0.00%
98	Non-Small Company	2670.5	23.39	\$0.0993	\$1,814.15	\$1.37	0.08%
99	Non-Small Company	1641.7	14.38	\$0.1100	\$1,370.68	\$2.49	0.18%
100	Non-Small Company	1566.8	13.73	\$0.1100	\$1,308.07	\$2.67	0.20%
101	Non-Small Company	3767.2	33.01	\$0.1100	\$3,145.38	\$2.55	0.08%
102	Non-Small Company	567.0	4.97	\$0.1020	\$438.82	\$0.20	0.05%
103	Non-Small Company	1514.0	13.26	\$0.1100	\$1,263.83	\$1.63	0.13%
104	Non-Small Company	2731.2	23.93	\$0.0934	\$1,935.54	\$4.90	0.25%
105	Non-Small Company	686.5	6.01	\$0.0934	\$486.01	\$0.15	0.03%
106	Non-Small Company	1075.7	9.43	\$0.0838	\$684.42	\$2.28	0.33%
107	Non-Small Company	3562.0	31.20	\$0.0822	\$2,531.68	\$9.43	0.37%
108	Non-Small Company	2216.0	19.41	\$0.0993	\$1,668.94	\$0.24	0.01%
109	Non-Small Company	613.8	5.38	\$0.0838	\$390.43	\$0.00	0.00%
110	Non-Small Company	70.0	0.61	\$0.1138	\$60.43	\$0.00	0.00%
111	Non-Small Company	2852.0	25.53	\$0.1111	\$2,454.93	\$1.51	0.06%
112	Non-Small Company	1781.8	12.79	\$0.0678	\$751.04	\$0.15	0.02%
113	Non-Small Company	18.0	0.16	\$0.0953	\$13.02	\$0.00	0.00%
114	Non-Small Company	35.4	0.31	\$0.1036	\$27.52	\$0.00	0.00%
115	Non-Small Company	101.1	0.88	\$0.1742	\$133.47	\$0.00	0.00%
116	Non-Small Company	6137.0	53.77	\$0.0993	\$4,622.73	\$14.21	0.31%
117	Non-Small Company	5771.8	50.55	\$0.1023	\$4,479.65	\$16.01	0.36%
118	Non-Small Company	575.7	5.05	\$0.0847	\$308.12	\$0.56	0.18%
119	Non-Small Company	7681.7	66.46	\$0.0965	\$5,366.42	\$18.05	0.34%
120	Non-Small Company	48.0	0.42	\$0.1100	\$40.07	\$0.00	0.00%
121	Non-Small Company	3274.5	28.13	\$0.1138	\$2,612.44	\$0.40	0.02%
122	Non-Small Company	2287.0	18.94	\$0.1062	\$1,741.49	\$6.07	0.35%
123	Non-Small Company	1604.6	14.05	\$0.1062	\$1,292.02	\$1.66	0.13%
124	Non-Small Company	36.0	0.32	\$0.1100	\$30.05	\$0.00	0.00%
125	Non-Small Company	58.1	0.51	\$0.0770	\$33.90	\$0.39	1.14%
126	Non-Small Company	1096.8	9.61	\$0.0768	\$639.49	\$3.15	0.49%

Exhibit C-2

Revenues and Costs Used for SBREFA and UMRA/Federalism Calculations

Entity ID	Entity Size	EIA Nameplate Capacity	Estimated Annual Million MWhs	Average Statewide Price (\$2013)	Annual Revenue (\$M)	Annual Cost (\$M)	Cost as % of Rev.
127	Non-Small Company	322.5	2.82	\$0.1742	\$425.51	\$0.22	0.05%
128	Non-Small Company	655.1	5.74	\$0.1742	\$865.55	\$0.48	0.06%
129	Non-Small Company	3016.0	25.91	\$0.0958	\$2,150.32	\$3.61	0.17%
130	Non-Small Company	5957.8	52.19	\$0.1240	\$4,265.74	\$7.78	0.18%
131	Non-Small Company	1863.2	20.30	\$0.1072	\$1,884.18	\$4.24	0.22%
132	Non-Small Company	1710.0	15.76	\$0.0998	\$1,406.94	\$1.49	0.11%
133	Non-Small Company	78.8	0.53	\$0.1000	\$46.27	\$0.00	0.00%
134	Non-Small Company	1221.3	10.70	\$0.0953	\$882.91	\$3.84	0.43%
135	Non-Small Company	242.0	2.12	\$0.1020	\$187.29	\$0.15	0.08%
136	Non-Small Company	2416.0	19.73	\$0.1518	\$2,592.64	\$1.64	0.06%
137	Non-Small Company	102.6	0.90	\$0.1279	\$99.94	\$0.00	0.00%
138	Non-Small Company	585.0	5.12	\$0.1100	\$488.34	\$0.00	0.00%
139	Non-Small Company	5818.8	51.32	\$0.0993	\$4,411.85	\$3.60	0.08%
140	Non-Small Company	136.0	1.19	\$0.1518	\$156.57	\$0.23	0.15%
141	Non-Small Company	669.3	5.86	\$0.0768	\$389.99	\$2.46	0.63%
142	Non-Small Company	240.1	2.10	\$0.0916	\$166.71	\$0.00	0.00%
143	Non-Small Company	808.0	7.08	\$0.0823	\$504.62	\$0.00	0.00%
144	Non-Small Company	1596.8	13.99	\$0.0833	\$1,009.67	\$0.15	0.01%
145	Non-Small Company	67.0	0.59	\$0.0973	\$49.48	\$0.00	0.00%
146	Non-Small Company	43.7	0.39	\$0.1036	\$34.59	\$0.00	0.00%
147	Non-Small Company	78.2	0.69	\$0.0934	\$55.40	\$0.00	0.00%
148	Non-Small Company	797.3	6.98	\$0.1023	\$618.66	\$0.94	0.15%
149	Non-Small Company	114.8	1.01	\$0.0965	\$84.22	\$0.00	0.00%
150	Non-Small Company	600.4	5.45	\$0.0993	\$468.45	\$1.78	0.38%
151	Non-Small Company	349.2	3.06	\$0.0993	\$262.84	\$0.42	0.16%
152	Non-Small Coop	3625.8	31.76	\$0.0814	\$1,996.84	\$2.99	0.15%
153	Non-Small Coop	1402.2	12.29	\$0.0814	\$866.49	\$1.84	0.21%
154	Non-Small Federal	20593.2	181.44	\$0.1000	\$14,860.24	\$80.94	0.54%
155	Non-Small State	1010.0	9.93	\$0.0860	\$739.66	\$0.59	0.08%
156	Non-Small State	1690.0	14.80	\$0.0993	\$1,272.79	\$0.45	0.04%
157	Non-Small State	1591.3	13.95	\$0.0884	\$1,067.81	\$0.68	0.06%
158	Non-Small State	1296.3	17.83	\$0.0884	\$1,364.95	\$3.23	0.24%
159	Non-Small State	800.4	7.01	\$0.1036	\$629.00	\$0.59	0.09%
160	Non-Small State	3231.1	28.30	\$0.1072	\$2,627.44	\$9.52	0.36%
161	Non-Small State	4228.3	37.04	\$0.0934	\$2,995.40	\$4.41	0.15%
162	Small City	31.9	0.28	\$0.0934	\$22.67	\$0.00	0.00%
163	Small City	51.5	0.46	\$0.0853	\$33.64	\$0.03	0.08%
164	Small City	24.9	0.22	\$0.0838	\$15.90	\$0.00	0.00%
165	Small City	49.6	0.44	\$0.0973	\$36.93	\$0.00	0.00%
166	Small City	170.0	1.49	\$0.0884	\$114.02	\$0.20	0.17%
167	Small City	80.0	0.70	\$0.1138	\$69.06	\$0.20	0.29%
168	Small City	59.0	0.40	\$0.0918	\$32.02	\$0.00	0.00%

Exhibit C-2

Revenues and Costs Used for SBREFA and UMRA/Federalism Calculations

Entity ID	Entity Size	EIA Nameplate Capacity	Estimated Annual Million MWhs	Average Statewide Price (\$2013)	Annual Revenue (\$M)	Annual Cost (\$M)	Cost as % of Rev.
169	Small City	76.3	2.84	\$0.0884	\$217.32	\$1.62	0.75%
170	Small City	35.9	0.32	\$0.0934	\$25.50	\$0.00	0.00%
171	Small City	62.8	0.55	\$0.1138	\$54.38	\$0.35	0.64%
172	Small City	101.0	0.84	\$0.1742	\$126.86	\$0.00	0.00%
173	Small City	101.0	0.84	\$0.0838	\$61.06	\$0.00	0.00%
174	Small City	37.2	0.05	\$0.1036	\$4.72	\$0.00	0.00%
175	Small City	61.0	0.53	\$0.0838	\$38.80	\$0.00	0.00%
176	Small City	138.4	1.08	\$0.1062	\$99.08	\$0.00	0.00%
177	Small City	77.5	0.57	\$0.1138	\$56.11	\$0.00	0.00%
178	Small City	57.3	0.50	\$0.1023	\$44.25	\$0.00	0.00%
179	Small City	58.2	0.51	\$0.1138	\$50.07	\$0.00	0.00%
180	Small City	293.5	2.58	\$0.0853	\$190.18	\$0.03	0.01%
181	Small City	84.5	0.63	\$0.0973	\$53.17	\$0.00	0.00%
182	Small City	53.5	0.49	\$0.0973	\$41.36	\$0.00	0.00%
183	Small City	38.0	0.33	\$0.0853	\$24.58	\$0.00	0.00%
184	Small City	36.3	0.32	\$0.0838	\$22.90	\$0.00	0.00%
185	Small City	15.5	0.07	\$0.0998	\$6.06	\$0.00	0.00%
186	Small City	93.9	0.82	\$0.0838	\$59.79	\$0.40	0.67%
187	Small City	40.0	0.09	\$0.0973	\$7.39	\$0.00	0.00%
188	Small City	261.0	2.29	\$0.1023	\$202.60	\$0.34	0.17%
189	Small City	453.5	3.98	\$0.0993	\$341.92	\$1.36	0.40%
190	Small City	30.2	0.23	\$0.0934	\$18.42	\$0.00	0.00%
191	Small City	26.0	0.26	\$0.0934	\$21.25	\$0.00	0.00%
192	Small City	78.4	0.68	\$0.1138	\$67.33	\$0.00	0.00%
193	Small City	109.8	0.96	\$0.0884	\$73.78	\$0.20	0.27%
194	Small Company	60.0	0.53	\$0.1529	\$69.58	\$0.00	0.00%
195	Small Company	29.0	0.25	\$0.1655	\$35.15	\$0.00	0.00%
196	Small Company	0.0	12.29	\$0.1062	\$1,130.11	\$0.00	0.00%
197	Small Company	2353.9	20.62	\$0.0768	\$1,372.26	\$9.04	0.66%
198	Small Company	55.5	0.49	\$0.1742	\$74.00	\$0.00	0.00%
199	Small Company	60.0	0.35	\$0.1138	\$34.53	\$0.00	0.00%
200	Small Company	98.0	0.86	\$0.1100	\$81.81	\$0.00	0.00%
201	Small Company	1880.4	16.47	\$0.0973	\$1,388.38	\$8.92	0.64%
202	Small Company	41.5	0.40	\$0.0851	\$29.68	\$0.14	0.48%
203	Small Company	512.9	4.49	\$0.0958	\$384.36	\$2.06	0.54%
204	Small Company	88.4	0.77	\$0.1100	\$73.46	\$0.00	0.00%
205	Small Company	30.8	0.27	\$0.1655	\$38.91	\$1.51	3.89%
206	Small Company	1313.2	11.50	\$0.0838	\$835.18	\$2.77	0.33%
207	Small Company	118.0	1.03	\$0.1100	\$98.50	\$0.00	0.00%
208	Small Company	114.8	1.01	\$0.0965	\$84.22	\$0.00	0.00%
209	Small Company	94.0	0.82	\$0.1100	\$78.47	\$0.00	0.00%
210	Small Company	1423.1	12.47	\$0.1543	\$1,370.10	\$0.00	0.00%

Exhibit C-2

Revenues and Costs Used for SBREFA and UMRA/Federalism Calculations

Entity ID	Entity Size	EIA Nameplate Capacity	Estimated Annual Million MWhs	Average Statewide Price (\$2013)	Annual Revenue (\$M)	Annual Cost (\$M)	Cost as % of Rev.
211	Small Company	1766.0	15.47	\$0.0953	\$1,276.99	\$0.00	0.00%
212	Small Company	38.2	0.33	\$0.1529	\$44.07	\$0.00	0.00%
213	Small Company	38.2	0.33	\$0.1529	\$44.07	\$0.00	0.00%
214	Small Company	115.7	1.02	\$0.0851	\$74.86	\$0.00	0.00%
215	Small Company	99.2	0.87	\$0.1100	\$82.64	\$0.00	0.00%
216	Small Company	348.7	3.06	\$0.0958	\$253.71	\$0.23	0.09%
217	Small Company	40.9	0.36	\$0.1138	\$35.39	\$0.00	0.00%
218	Small Company	490.6	4.30	\$0.1100	\$409.87	\$1.02	0.25%
219	Small Company	47.3	0.41	\$0.1100	\$39.23	\$0.57	1.45%
220	Small Company	44.1	0.39	\$0.0916	\$30.56	\$0.00	0.00%
221	Small Company	114.8	1.01	\$0.0916	\$79.88	\$0.00	0.00%
222	Small Company	229.6	2.01	\$0.0965	\$168.44	\$0.00	0.00%
223	Small Company	483.6	4.24	\$0.1543	\$566.53	\$0.00	0.00%
224	Small Company	56.0	0.49	\$0.1742	\$74.00	\$0.00	0.00%
225	Small Company	720.0	6.31	\$0.0822	\$449.11	\$0.00	0.00%
226	Small Company	202.5	1.78	\$0.0916	\$141.01	\$0.00	0.00%
227	Small Cooperative	538.0	4.71	\$0.1000	\$408.09	\$1.42	0.35%
228	Small Cooperative	660.7	5.79	\$0.1072	\$537.52	\$2.16	0.40%
229	Small Cooperative	2335.0	21.74	\$0.1023	\$1,926.62	\$3.92	0.20%
230	Small Cooperative	59.0	0.52	\$0.1023	\$45.80	\$0.41	0.91%
231	Small Cooperative	143.0	1.25	\$0.0853	\$92.50	\$0.03	0.03%
232	Small Cooperative	913.6	7.61	\$0.1062	\$699.98	\$0.28	0.04%
233	Small Cooperative	1839.1	18.99	\$0.0768	\$1,263.83	\$8.60	0.68%
234	Small Cooperative	734.0	6.43	\$0.0814	\$453.32	\$1.11	0.25%
235	Small Cooperative	410.0	3.59	\$0.0993	\$308.78	\$3.26	1.06%
236	Small Cooperative	400.0	3.50	\$0.0918	\$278.46	\$0.79	0.28%
237	Small Cooperative	422.0	3.70	\$0.0953	\$305.15	\$5.28	1.73%
238	Small Cooperative	446.0	3.91	\$0.0860	\$290.90	\$0.62	0.21%
239	Small Cooperative	1429.2	12.89	\$0.1111	\$1,240.10	\$0.38	0.03%
240	Small Cooperative	499.5	4.38	\$0.0770	\$292.24	\$1.60	0.55%
241	Small Cooperative	46.0	0.21	\$0.0953	\$17.35	\$0.38	2.21%
242	Small County	17.5	0.16	\$0.1088	\$14.86	\$0.26	1.72%

APPENDIX D

Description of Fortran-Based CCR Landfill & Surface Impoundment Pollution Control Cost Model

Exhibit D-1: CCR Combination Landfill Cost Equations

Exhibit D-2: CCR Pile-Design Landfill Cost Equations

Exhibit D-3: CCR Surface Impoundment Cost Equations

Note: This appendix was originally included for the RIA for the proposed CCR rule. The information and equation on the following pages remains accurate and properly reflects the underlying Fortran-based equations used in this RIA, with two exceptions:

- *While all cost equations presented in this appendix are in 2011\$, they have been inflated to 2013\$ using the Engineering News Record Construction Cost Index for use in this RIA; and*
- *In prior versions of this RIA, including the RIA for the proposed CCR rule, the Fortran-based equations presented in this appendix constituted the entirety of the unit-level costs assigned to the CCR management units examined. However, because the CCR final rule requires some unit-level pollution control requirements for surface impoundments (i.e., dust controls and run-on/run-off controls) that were not available via the Fortran-based equations, these costs are considered separately and are not included in these equations. Similarly, because the Fortran-based equations did not account for CCR storage impoundments, the equations in Exhibit D-3 reflect only the equations assigned to CCR disposal impoundments. For additional information on the cost elements not codified in this appendix, see Chapters 3 and 4.*

Description of CCR Landfill & Surface Impoundment Pollution Control Cost Model

A. Introduction to Cost Model

The CCR landfill and surface impoundment pollution control cost model consists of two electronic (computer) components:

1. Single Disposal Unit Cost Estimation Model: The first component is a Fortran computer programmed cost model which dates back to 1988. This model specifies the various steps and physical units (e.g., specified square footage size and associated quantities of labor, equipment and materials for the specified size) involved in designing, constructing, operating, and closing a landfill or impoundment. Then it combines this information with data on the costs/fees for the physical components to estimate the capital and annual O&M costs of a specified landfill or impoundment. The cost components include a wide range of items, such as land, clearing, excavation, equipment, labor, liner materials, and cover materials. The model was re-run multiple times to generate individual cost estimates for a series of five alternatively-sized landfills and surface impoundments to represent the range of sizes in the population of 507 electric utility plants. The size categories are defined in tons per day of CCR disposed. Each landfill or impoundment is assumed to operate 300 days per year (average number of operating days for coal-fired boilers based on 2005 DOE EIA 767 database). The size categories are 10,000, 50,000, 200,000, 500,000 and 2,000,000 tons of CCR per year. Size is the primary determinant

of overall cost; however, landfills and impoundments exhibit increasing returns to scale: the larger the landfill or impoundment, the lower the cost per ton of CCR managed.

2. Plant-by-Plant & Industry-Wide Cost Aggregation Model: The second component of the model consists of cost data and calculations formulated using Excel spreadsheets. This second component computes landfill and impoundment cost curves across the low-to-high annual tonnage size ranges so that a unique baseline and regulatory option cost may be estimated for each of the 507 electric utility plants based on each plant's 2009 aggregate annual CCR tonnage disposed.

Additional details about each of the cost modeling components are supplied below.

B. Cost Model Component 1 of 2: Single Disposal Unit Cost Estimation

Facility Design in Model Component 1

The model's initial computer program routine calculates the physical dimensions and variables of the landfill or impoundment. The model includes several basic assumptions (e.g., the landfill unit is square) but allows the user to specify a range of variables:

- Waste characteristics: quantity, density, and operating life
- Unit dimensions: depth of excavation, below-grade slopes, cover slopes, and height above grade
- Containment and cover designs: drainage systems, cover materials and thicknesses (up to ten layers), containment system materials and thicknesses (up to ten layers), and leachate collection and treatment systems
- Groundwater monitoring options: the algorithm for estimating number of wells and monitoring costs are calculated outside model for CCR landfills and impoundments.

The model then calculates the materials and activities required to support these options:

- Labor inputs: hours needed to design, construct, and operate systems at the facility
- Materials costs: costs for land, heavy machinery and equipment, roads, fencing, fill material, and liner and cover material
- Indirect costs: engineering, testing, quality assurance (QA), contingency, and contractors' fees on materials and installation.

Within a model run, the model specifies the components required to construct and operate a landfill and the costs associated with each.

Facility Costs in Model Component 1

The model summarizes the estimated facility costs for each design simulated, calculating costs for direct capital, indirect capital, operation and maintenance, closure, and post-closure.

Direct Capital

Capital costs are substantial for these landfills; they include the large initial costs, such as equipment purchase, land purchase, excavation, site preparation, design, and any environmental monitoring or containment systems. Capital costs also occur intermittently throughout the operating life of the landfill when equipment used to operate the landfill is purchased (i.e., sheepsfoot rollers and water trucks). The number of equipment pieces used depends on the size of the landfill. Capital costs for covering the landfill occur at closure and are discussed below.

Indirect Capital

Indirect capital costs constitute a substantial fraction of the total cost of capital:

- Contractor's fee: profit for construction contractor
- Construction and field expenses: cost of temporary construction and other overhead
- Spare parts: cost of equipment and parts for maintenance
- Contingency: costs for unpredicted events and design changes
- Inspection and testing: cost for a testing company to ensure that design specifications are met
- Quality assurance: additional fee to cover added cost of inspecting, testing, and documenting that design specifications for containment and cover systems have been met

The percentages used for each of these costs are set by the user.

Operation and Maintenance

The model determines the need for labor hours on the basis of the quantity of waste handled; the different categories of labor hours required are linked to the equipment costs described earlier as direct capital costs. Other annual cost components include equipment maintenance and fuel, fees for licenses or permits, environmental-monitoring costs (which are estimated outside the model; discussed below), and costs for leachate management (if applicable). For this analysis, all collected leachate is assumed to be trucked off site to a publicly owned treatment works (POTW).

Closure

The dominant cost at closure is for the final cover applied to the landfill. The model includes the direct and indirect capital cost components for the cover, its design, the appropriate drainage system, and final vegetation for the site. When financial assurance is required for the disposal unit, closure costs must be provided for prior to unit closure, as part of the financial assurance requirements. However, when no financial assurance is required for the disposal unit, closure costs accrue in the 40-year post-closure period. When discounting and time value of money (TVM) adjustments are applied, closure costs are lower for units where financial assurance is not required, relative to similar units for which financial assurance is required.

Post-Closure

Post-closure care costs after the unit no longer accepts waste includes applicable environmental monitoring, leachate treatment, cover and slope maintenance, and annual inspections for a 30-year period of care. When financial assurance is required for the disposal unit, post-closure costs must be provided for prior to unit closure, as part of the financial assurance requirements. However, when no financial assurance is required for the disposal unit, post-closure costs accrue in the 40-year post-closure period. When discounting and time value of money (TVM) adjustments are applied, post-closure costs are lower for units where financial assurance is not required, relative to similar units for which financial assurance is required.

Generic Design and Operating Inputs to the Model Component 1

The model is capable of analyzing a wide range of environmental control options for baseline and regulatory options, so constrained the number of possible user inputs to focus on design variables affected by the proposed rule. The specifications for the baseline and CCR proposed rule design options are discussed later. Other physical design variables were set independently of the requirements so they do not vary over the different options. These variables are described below.

Design Inputs

The landfills and impoundments are assumed to operate in one construction phase (i.e., one large cell or monofill) as a simplifying assumption. All the excavation is done initially and the final cover is placed over the waste at the end of the operating life. Technically, landfill units (as opposed to surface impoundment units) likely are constructed in several phases (e.g., one cell per year).

The compacted dry waste density for landfills is assumed to be $1,190 \text{ kg/m}^3$; the in-situ wet waste density for surface impoundments is assumed to be 900 kg/m^3 . A compaction factor of 1.25 to convert bulk waste volumes to compacted waste volumes is assumed.

The side slopes of the excavation are set at 3:1 (rise:run). The amount of fill below grade is assumed to be 50 percent for combination fill landfills (with a maximum depth of 15 feet), five percent for pile-design landfills (with a maximum depth of 1 foot), and 100 percent for surface impoundments (with a maximum depth of 15 feet).

The slope of the cover (cap) is set at 0.02:1 (rise:run) with a cover toe slope of 4:1 (rise:run).

Operating Parameters

All the landfills are assumed to either use a combination-fill method or pile-design method of operation. For combination-fill landfills the operator excavates a large trench (monofill area) and places waste both below grade (in the excavation trench) and above grade (in the mound). For a pile-design landfill the operator places wastes above grade (in the mound). The more economical choice (least cost) of constructing a combination fill landfill versus a pile-design

landfill is assumed for existing units. The more economical choice of constructing a combination fill landfill versus a pile-design landfill versus off-site commercial landfill is assumed when new units are constructed. All landfill operators are assumed to compact ash in landfills to conserve landfill space and maximize the return on their investment. All impoundments are assumed to have their 100 percent of their capacity below grade. A berm is constructed around the impoundment for use as freeboard. The more economical choice of constructing a surface impoundment versus combination fill landfill versus a pile-design landfill versus off-site commercial landfill is assumed when new units are constructed.¹

All new landfills and impoundments are assumed to operate for 40 years; existing landfills and impoundments have remaining lives based on either their actual (if known) or estimated start date. Impoundments are closed as landfills with CCR materials left in place. Post-closure care is assumed to extend for 30 years after closure of the unit.

Time Value of Money Adjustments to the Engineering Cost Estimates

The model's unadjusted output presents the sum of all costs (in current, 2011 dollars) for each year of operation and, if applicable, throughout the post-closure period. To apply the results to the economic analysis and take account of the time value of money, the model discounts the costs using a 7% discount rate to provide the present value of the stream of future annual costs.

The cost model generates annual before-tax cost estimates for baseline state-regulated landfills and impoundments, and subtracts costs from the annual before-tax costs for regulated units. The difference equals the incremental cost attributable to the regulation. In estimating the incremental cost per year, the model assumed that the operator will recover the costs over the entire active life of the disposal unit. The present value of the incremental cost estimated by the model for 40 years of operation and for 30 years of post-closure care is annualized over the 40-year operating period. A sample of electric utility industry representatives provided a 40-year estimate for both types of disposal units (landfills and impoundments). This estimate is supported by data provided by industry in the 1995 EPRI Comanagement Survey. In the EPRI Survey, data describing six landfills noted the year the unit was opened and the estimated date of closure. The average life expectancy is 34 years and the median life expectancy is 38 years. Similarly, data provided for 18 surface impoundments indicate an average life expectancy of 45 years and a median life expectancy of 46 years. Therefore, a 40-year life expectancy for ash landfills and surface impoundments is assumed. For existing waste management units, the

¹ In July 2009, ORCR contacted the DOE-EIA Form 767 questionnaire contact person (Natalie Ko, Electric Power Division) to confirm this RIA's assignment of all "off-site disposal" tonnages as commercial landfills. The DOE-EIA contact person responded with additional information from four 2005 Form EIA-767 questionnaires regarding how electricity plant respondents "optionally" characterized the fly ash and bottom ash reported in the Form EIA-767 survey questionnaire as "Off Site Disposal":

- "This quantity of fly ash was given away at no cost"
- "The fly ash was sent off site for beneficial use"
- "The fly ash is injected into the nearby mines for recharging the mines"
- "Ash is recycled as a beneficial re-use product for flowable fill in the construction industry"

This RIA assumes that off-site disposal means offsite commercial landfill. Plants could have reported off-site minefill in this category if it was not "sold" (e.g., they paid to dispose it in a mine or it was used as minefill and no payment was made to the electric utility). However, it is unknown the sub-quantity of "off-site disposal" which includes plants reporting tonnages for non-sold uses such as offsite minefill.

remaining years of the unit's operating life is assumed as the borrowing period (n) for application of new environmental controls (e.g., groundwater monitoring).

Some elements of the regulatory options have different requirements for new and existing landfills and impoundments. This difference has implications for adjustments to the cost model results, and the approach taken is described next.

New Landfills and Impoundments

All requirements that affect new units are assumed to apply from the time construction begins. The incremental cost is the cost difference between replacing the unit with a new regulated unit and a new state-regulated unit, taking into account the time at which construction begins. The model assumed that each landfill identified will be replaced at the end of its active life with a new landfill that conforms to the appropriate requirements. If the landfill is estimated to close before the effective date of the rule (2013), the model assumed a new state-regulated unit would be opened. This assumption provides a reasonable upper-bound estimate of the regulatory costs because it does not allow for lower-cost compliance approaches, such as regionalized units or beneficial use. The model cost estimates are based on a 40-year active life for CCR landfills and impoundments.

Existing Landfills and Impoundments

The approach for estimating costs for existing units is more complicated. As described for new units, a landfill owner is likely to estimate all the costs that will be incurred over the lifetime of the unit and the revenue required to offset those costs. If EPA promulgates new regulations applicable to the unit, any incremental costs are added to the cost burden for which the owner has already planned. The key point is that between the first year of operation and the year in which new rules take effect, the owner has no notion of the increase and did not set aside funds for such contingencies.

If a landfill has an expected life of 40 years and has 10 years remaining, all the costs paid over the first 30 years are considered sunk costs and do not affect the calculation of incremental costs resulting from the regulation. The difference measured is the increase in costs (over the remaining life) brought about by the new regulations. These could include capital costs for new equipment in the year the regulation become effective, incremental O&M costs in subsequent years of operation, incremental closure costs assuming more stringent closure requirements, continued monitoring costs after closure, and, possibly, corrective action.

The incremental present-value costs of such requirements can be annualized over the remaining life of the landfill or impoundment or some of the costs can be passed on to future landfills and impoundments, particularly when publicly owned. The longer the remaining life of the unit, the smaller the incremental cost and the less likely that costs will be passed on to the future. For this analysis costs to comply with the regulation at existing units are annualized over the remaining life of the landfill or impoundment. This assumption provides an upper-bound estimate of the regulatory costs.

Combination of New and Existing Units

To develop a combined estimate of average annualized compliance costs from the regulatory option, the costs for existing units plus new replacement landfills and impoundments have been discounted to a present value that spans the existing landfill's remaining life plus the ongoing life of the new landfill that is replaced every 40 years for a 100-year time horizon (2013 – 2112). This present value is then annualized over 100 years to calculate a level annual cost of the regulatory option. This figure is the best single point estimate of the overall cost impact of the option; however, it does not reflect the actual cash flows that would be required, particularly for capital costs. Instead, the annualized cost figure represents level annual payments as though the landfill owner borrowed funds to pay capital costs. This combined annualized cost estimate is used to calculate economic impacts.

C. Cost Model Component 2 of 2: Plant-by-Plant and Industry-Wide Cost Aggregation

To estimate the costs and effects of the regulatory options compared to those of the baseline, numerous baseline and regulatory cost equations were developed to account for the variability in state regulatory requirements and site-specific practices being conducted at each landfill or impoundment. For each possible combination of engineering controls (e.g., no controls; groundwater monitoring only; groundwater monitoring and synthetic liner; groundwater monitoring and composite liner; groundwater monitoring and clay cap; groundwater monitoring, clay cap and post-closure monitoring; groundwater monitoring, clay cap and financial assurance; etc.), the model was run for each CCR disposal unit size category (i.e., 10,000, 50,000, 200,000, 500,000 and 2,000,000 tons CCR per year). Cost outputs from model runs were entered into an Excel spreadsheet. A linear cost equation in the form of $Y = aX + b$ using regression functions available in Excel Spreadsheet software were calculated. "Y" represents the total annualized cost estimate for a facility of size "X" in tons per year. A linear cost equation was developed for each combination of engineering controls. See **Exhibits D-1, D-2, and D-3** for the list of linear cost equations.

The cost equations for each proposed engineering control (i.e., technical standard) were entered into a separate Excel spreadsheet for use in estimating annualized cost estimates on a plant-by-plant specific basis. Each plant's unit size (i.e., tons of CCR landfilled or impounded per year) is entered into the appropriate cost equation to determine the annualized cost estimate. The spreadsheet assigned a cost equation to each plant to estimate baseline costs for their existing units and assigned a second equation to each plant to estimate baseline costs for their projected future new disposal units to replace existing units upon end-of-lifespan (within the future 100-year period-of-analysis). The spreadsheet also assigned a cost equation to each plant to estimate the average annualized total cost for each regulatory option under consideration. This spreadsheet of cost equations were inputted into an Access Cost Model to aggregate costs for each regulatory option.

Exhibit D-1 Combination Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
0000000000000000	10	No Controls	\$22.49	\$78,162
1001000101001111	2	UBM, Clay Liner, LCS, Clay Cap, FA, Dust, Run-on/off, PCM	\$53.93	\$303,466
1000000001000000	4	UBM, Clay Cap	\$24.43	\$140,213
0000100000010000	5	Ash Liner, Soil Cap	\$27.88	\$106,189
1001000101001110	6	UBM, Clay Liner, LCS, Clay Cap, FA, Dust, Run-on/off	\$53.92	\$300,463
1001000001001101	12	UBM, Clay Liner, Clay Cap, FA, Dust, PCM	\$46.95	\$241,603
1010000110000000	15	UBM, Liner, LCS, Cap	\$56.69	\$308,929
0110000110000000	16	150M Mon, Liner, LCS, Cap	\$56.69	\$332,613
0110000110001001	18	150M Mon, Liner, LCS, Cap, FA, PCM	\$58.05	\$347,732
1001000110001101	19	UBM, Clay Liner, LCS, Cap, FA, Dust, PCM	\$53.14	\$292,927
1010000110001111	22	UBM, Liner, LCS, Cap, FA, Dust, Run-on/off, PCM	\$58.39	\$331,701
0000000000011001	25	Soil Cap, FA, PCM	\$24.65	\$97,530
1010000110001101	27	UBM, Liner, LCS, Cap, FA, Dust, PCM	\$58.33	\$324,262
1000000000001101	28	UBM, FA, Dust, PCM	\$24.22	\$146,931
1000000000000000	29	UBM	\$22.59	\$131,599
1001000001001111	30	UBM, Clay Liner, Clay Cap, FA, Dust, Run-on/off, PCM	\$47.00	\$249,042
1000000000000001	31	UBM, PCM	\$22.59	\$134,601
1000000010001001	32	UBM, Cap, FA, PCM	\$25.07	\$152,231
1010000101001110	33	UBM, Liner, LCS, Clay Cap, FA, Dust, Run-on/off	\$59.11	\$331,798
0101000000010001	34	150M Mon, Clay Liner, Soil Cap, PCM	\$44.27	\$248,593
1001000010001001	36	UBM, Clay Liner, Cap, FA, PCM	\$45.94	\$238,290
1000000000100000	37	UBM, Ash Cap	\$23.53	\$137,576
0100000000000001	38	150M Mon, PCM	\$22.59	\$158,286
0110000110000001	39	150M Mon, Liner, LCS, Cap, PCM	\$56.69	\$335,616
1000000001000001	40	UBM, Clay/Soil Cap, PCM (uncompacted)	\$27.55	\$111,056
0001000001000000	41	Clay Liner, Clay Cap	\$45.20	\$172,834
0001000001000000a	41a	Clay Liner, Clay Cap, (cap cost accrues after closure)	\$43.50	\$164,897
0100000001000001	42	150M Mon, Clay/Soil Cap, PCM (uncompacted)	\$27.55	\$136,008
1010000000100000	43	UBM, Liner, Ash Cap	\$49.60	\$254,969
1001000100010000	44	UBM, Clay Liner, LCS, Soil Cap	\$51.18	\$276,330
1010000000011100	46	UBM, Liner, Soil Cap, FA, Dust	\$51.08	\$265,571
1010000110001001	47	UBM, Liner, LCS, Cap, FA, PCM	\$58.05	\$324,047
1000000000011100	48	UBM, Soil Cap, FA, Dust	\$25.01	\$148,178

Exhibit D-1 Combination Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
0100000010001001	49	150M Mon, Cap, FA, PCM (compacted)	\$25.07	\$175,915
0010000000000000	53	Liner	\$48.55	\$195,555
0000000010001001	59	Cap, PCM, FA	\$24.97	\$98,794
1010000101000111	60	UBM, Liner, LCS, Clay Cap, Dust, Run-on/off, PCM	\$57.75	\$322,685
1001000000010000	62	UBM, Clay Liner, Soil Cap	\$44.26	\$221,906
0101000001000000	63	150M Mon, Clay Liner, Clay Cap	\$45.30	\$249,955
0101000000010000	64	150M Mon, Clay Liner, Soil Cap	\$44.26	\$245,590
0100000001000000	65	150M Mon, Clay/Soil Cap	\$27.54	\$131,491
0010000110000000	66	Liner, LCS, Cap	\$56.60	\$255,492
0110000100000000	67	150M Mon, Liner, LCS	\$55.57	\$327,100
0100000010001111	70	150M Mon, Cap, FA, Dust, Run-on/off, PCM	\$25.38	\$183,467
1000000010000001	74	UBM, Cap, PCM	\$23.71	\$140,115
0101000010000001	75	150M Mon, Clay Liner, Cap, PCM	\$44.58	\$249,857
0100000010000001	77	150M Mon, Cap, PCM	\$23.71	\$163,799
1010000101001111	78	UBM, Liner, LCS, Clay Cap, FA, Dust, Run-on/off, PCM	\$59.11	\$334,801
1000000001001111	79	UBM, Clay Cap, FA, Dust, Run-on/off, PCM	\$26.14	\$162,984
0101000010001001	83	150M Mon, Clay Liner, Cap, FA, PCM	\$45.94	\$261,973
1010000000000000	85	UBM, Liner	\$48.65	\$248,992
1010000000000001	87	UBM, Liner, PCM	\$48.66	\$251,995
1010000100000000	88	UBM, Liner, LCS	\$55.57	\$303,416
1001000000000000	89	UBM, Clay Liner	\$43.46	\$217,657
1000000010000000	90	UBM, Cap	\$23.71	\$137,113
1000000000001100	91	UBM, FA, Dust	\$24.22	\$143,929
1000000000010000	92	UBM, Soil Cap	\$23.38	\$135,848
1000100000010000	93	UBM, Ash Liner, Soil Cap	\$27.98	\$159,626
1001000001000000	94	UBM, Clay Liner, Clay Cap	\$45.30	\$226,270
1010000000010000	95	UBM, Liner, Soil Cap	\$49.45	\$253,241
0001000000000000	98	Clay Liner	\$43.36	\$164,220
0000000001000000	99	Clay Cap	\$24.33	\$86,776
1010000110000110	100	UBM, Liner, LCS, Cap, Dust, Run-on/off	\$57.02	\$316,582
1000000001000111	101	UBM, Clay Cap, Dust, Run-on/off, PCM	\$24.76	\$150,869
1000000000000100	104	UBM, Dust	\$22.86	\$131,813
0010000100000000	105	Liner, LCS	\$55.47	\$249,979
0010000110000010	106	Liner, LCS, Cap, Run-on/off	\$56.65	\$262,931
1010000110000010	107	UBM, Liner, LCS, Cap, Run-on/off	\$56.75	\$316,368

Exhibit D-1 Combination Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
0010000100000100	108	Liner, LCS, Dust	\$55.75	\$250,192
0000000000000010	109	Run-on/off	\$22.55	\$85,601
0000000001000010	110	Clay Cap, Run-on/off	\$24.39	\$94,215
1000000001000010	111	UBM, Clay Cap, Run-on/off	\$24.49	\$147,652
0000000010000000	112	Cap	\$23.61	\$83,675
0000000000100000	113	Ash Cap	\$23.44	\$84,139
0001000010000000	114	Clay Liner, Cap	\$44.49	\$169,734
1001000010000000	115	UBM, Clay Liner, Cap	\$44.58	\$223,171
0000000000010000	116	Soil Cap	\$23.28	\$82,411
0000000000010000a	116a	Soil Cap (cap cost accrues after closure)	\$22.55	\$78,615
0010000001000000	117	Liner, Clay Cap	\$50.40	\$204,169
0010000101000000	118	Liner, LCS, Clay Cap	\$57.31	\$258,593
0010000101000000a	118a	Liner, LCS, Clay Cap (cap cost accrues after closure)	\$55.61	\$250,656
0000000000000100	119	Dust	\$22.76	\$78,376
0000000000000110	120	Dust, Run-on/Off	\$22.81	\$85,815
0000000001000110	121	Clay Cap, Dust, Run-on/off	\$24.67	\$94,428
1000000001000110	122	UBM, Clay Cap, Dust, Run-on/off	\$24.76	\$147,866
0000000000000001	123	PCM with Construction	\$22.49	\$81,165
1000000001000011	124	UBM, Clay Cap, Run-on/off, PCM	\$24.50	\$150,654
0000000000010001	125	Soil Cap, PCM	\$23.29	\$85,414
1010000110000011	126	UBM, Liner, LCS, Cap, Run-on/off, PCM	\$56.76	\$319,371
0010000100000010	127	Liner, LCS, Run-on/off	\$55.54	\$257,418
1010000110000111	128	UBM, Liner, LCS, Cap, Dust, Run-on/off, PCM	\$57.03	\$319,584
1010000110000111a	128a	UBM, Liner, LCS, Cap, Dust, Run-on/off, PCM (cap and PCM costs accrue after closure)	\$56.02	\$314,722
0010000110000110	129	Liner, LCS, Cap, Dust, Run-on/off	\$56.92	\$263,145
0010000100000110	130	Liner, LCS, Dust, Run-on/off	\$55.80	\$257,631
1001000010000001	131	UBM, Clay liner, Cap, PCM	\$44.58	\$226,173
0010000000010000	132	Liner, Soil Cap	\$49.35	\$199,804
0010000000010000a	132a	Liner, Soil Cap (cap cost accrues after closure)	\$48.62	\$196,008
0000000010000001	134	Cap, PCM	\$23.61	\$86,679
0010000101000100	135	Liner, LCS, Clay Cap, Dust	\$57.59	\$258,806
0010000101000110	136	Liner, LCS, Clay Cap, Dust, Run-on/off	\$57.65	\$266,245
1010000001000000	137	UBM, Liner, Clay Cap	\$50.50	\$257,606
0010000101000010	138	Liner, LCS, Clay Cap, Run-on/off	\$57.38	\$266,032
1010000101000110	140	UBM, Liner, LCS, Clay Cap, Dust, Run-on/off	\$57.75	\$319,682

Exhibit D-1 Combination Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
1010000101000010	142	UBM, Liner, LCS, Clay Cap, Run-on/off	\$57.48	\$319,468
1010000101000011	143	UBM, Liner, LCS, Clay Cap, Run-on/off, PCM	\$57.49	\$322,471
1010000101001011	144	UBM, Liner, LCS, Clay Cap, FA, Run-on/off, PCM	\$58.85	\$334,587
1010000110001011	145	UBM, Liner, LCS, Cap, FA, Run-on/off, PCM	\$58.12	\$331,486
0010000100010010	146	Liner, LCS, Soil Cap, Run-on/off	\$56.33	\$261,667
1010000100010010	147	UBM, Liner, LCS, Soil Cap, Run-on/off	\$56.43	\$315,103
1010000100010011	148	UBM, Liner, LCS, Soil cap, Run-on/off, PCM	\$56.44	\$318,107
1010000100011011	149	UBM, Liner, LCS, Soil Cap, FA, Run-on/off, PCM	\$57.80	\$330,222
1010000101000000	150	UBM, Liner, LCS, Clay Cap	\$57.41	\$312,029
0010000100010110	151	Liner, LCS, Soil Cap, Dust, Run-on/off	\$56.61	\$261,881
1010000100010110	152	UBM, Liner, LCS, Soil Cap, Dust, Run-on/off	\$56.70	\$315,318
1010000100010111	153	UBM, Liner, LCS, Soil Cap, Dust, Run-on/off, PCM	\$56.70	\$318,320
1010000100011111	154	UBM, Liner, LCS, Soil Cap, FA, Dust, Run-on/off, PCM	\$58.08	\$330,436
0010000000000100	155	Liner, Dust	\$48.82	\$195,769
0010000000010100	156	Liner, Soil Cap, Dust	\$49.62	\$200,018
1010000000010100	157	UBM, Liner, Soil Cap, Dust	\$49.72	\$253,455
0001000000000100	158	Clay Liner, Dust	\$43.63	\$164,435
0001000000000110	159	Clay Liner, Dust, Run-on/off	\$43.69	\$171,874
0001000001000110	160	Clay Liner, Clay Cap, Dust, Run-on/off	\$45.54	\$180,487
1001000001000110	161	UBM, Clay Liner, Clay Cap, Dust, Run-on/off	\$45.64	\$233,924
1001000001000111	162	UBM, Clay Liner, Clay Cap, Dust, Run-on/off, PCM	\$45.64	\$236,926
0001000100000000	163	Clay Liner, LCS	\$50.28	\$218,644
0001000100000100	164	Clay Liner, LCS, Dust	\$50.55	\$218,858
0001000100000110	165	Clay Liner, LCS, Dust, Run-on/off	\$50.61	\$226,297
0001000101000110	166	Clay Liner, LCS, Clay Cap, Dust, Run-on/off	\$52.46	\$234,910
1001000101000110	167	UBM, Clay Liner, LCS, Clay Cap, Dust, Run-on/off	\$52.56	\$288,347
1001000101000111	168	UBM, Clay Liner, LCS, Clay Cap, Dust, Run-on/off, PCM	\$52.56	\$291,350
0001000100010000	170	Clay Liner, LCS, Soil Cap	\$51.08	\$222,893
0001000100010000a	170a	Clay Liner, LCS, Soil Cap (cap cost accrues after closure)	\$50.35	\$219,097
1010000100000100	171	UBM, Liner, LCS, Dust	\$55.84	\$303,630
1010000100000110	172	UBM, Liner, LCS, Dust, Run-on/off	\$55.90	\$311,068

Exhibit D-1 Combination Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
1010000001001111	173	UBM, Liner, Clay Cap, FA, Dust, Run-on/off, PCM	\$52.20	\$280,377
0010000110000100	174	Liner, LCS, Cap, Dust	\$56.86	\$255,706
1010000110000100	175	UBM, Liner, LCS, Cap, Dust	\$56.95	\$309,143
1010000110000101	176	UBM, Liner, LCS, Cap, Dust, PCM	\$56.97	\$312,146
1010000110001010	177	UBM, Liner, LCS, Cap, FA, Run-on/off	\$58.12	\$328,484
0000100000000000	186	Ash Liner	\$27.07	\$101,940
0010000000100000	191	Liner, Ash Cap	\$49.51	\$201,532
0000000000010100	192	Soil Cap, Dust	\$23.56	\$82,625
1000000000010100	193	UBM, Soil Cap, Dust	\$23.65	\$136,062
1010000101000100	194	UBM, Liner, LCS, Clay Cap, Dust	\$57.68	\$312,244
1010000110001110	195	UBM, Liner, LCS, Cap, FA, Dust, Run-on/off	\$58.38	\$328,697
0000000001000011	196	Clay Cap, Run-on/off, PCM	\$24.40	\$97,218
1010000100011010	197	UBM, Liner, LCS, Soil Cap, FA, Run-on/off	\$57.79	\$327,219
1010000001000011	198	UBM, Liner, Clay Cap, Run-on/off, PCM	\$50.56	\$268,048
1010000010001001	200	UBM, Liner, Cap, FA, PCM	\$51.14	\$269,624
0010000101000111	202	Liner, LCS, Clay Cap, Dust, Run-on/off, PCM	\$57.65	\$269,249
0010000101000011	203	Liner, LCS, Clay Cap, Run-on/off, PCM	\$57.39	\$269,034
0010000001000011	204	Liner, Clay Cap, Run-on/off, PCM	\$50.47	\$214,611
0010000110000111	205	Liner, LCS, Cap, Dust, Run-on/off, PCM	\$56.93	\$266,148
1010000100011110	206	UBM, Liner, LCS, Soil Cap, FA, Dust, Run-on/off	\$58.07	\$327,433
0001000000000010	207	Clay Liner, Run-on/off	\$43.43	\$171,659
0001000001000010	208	Clay Liner, Clay Cap, Run-on/off	\$45.27	\$180,273
1001000001000010	209	UBM, Clay liner, Clay Cap, Run-on/off	\$45.37	\$233,710
1001000001000011	210	UBM, Clay liner, Clay Cap, Run-on/off, PCM	\$45.38	\$236,713
0000000100000000	2001	LCS,	\$29.40	\$132,585
0000000100011001	2002	LCS, Soil Cap, FA, PCM,	\$31.57	\$151,953
0000000110001001	2003	LCS, Synth Cap, FA, PCM,	\$31.90	\$153,217
0001000000010000	2004	Clay Liner, Soil Cap,	\$44.16	\$168,469
0001000000010000a	2004a	Clay Liner, Soil Cap (cap cost accrues after closure)	\$43.43	\$164,673
0001000000011001	2005	Clay Liner, Soil Cap, FA, PCM,	\$45.53	\$183,587
0001000010001001	2006	Clay Liner, Synth Cap, FA, PCM,	\$45.86	\$184,852
0001000100011001	2007	Clay Liner, LCS, Soil Cap, FA, PCM,	\$52.45	\$238,011
0001000101000000	2008	Clay Liner, LCS, Clay Cap,	\$52.12	\$227,258
0001000101000011	2009	Clay Liner, LCS, Clay Cap, Run on/off, PCM,	\$52.20	\$237,699

Exhibit D-1 Combination Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
0001000110001001	2010	Clay Liner, LCS, Synth Cap, FA, PCM,	\$52.77	\$239,275
0010000010001001	2011	Synth Liner, Synth Cap, FA, PCM,	\$51.05	\$216,187
0010000100011001	2012	Synth Liner, LCS, Soil Cap, FA, PCM,	\$57.64	\$269,346
0010000110001001	2013	Synth Liner, LCS, Synth Cap, FA, PCM,	\$57.97	\$270,610
1000000000011010	2014	UBM, Soil Cap, FA, Run on/off,	\$24.81	\$155,403
1000000000011011	2015	UBM, Soil Cap, FA, Run on/off, PCM,	\$24.82	\$158,405
1000000000011111	2016	UBM, Soil Cap, FA, Dust, Run on/off, PCM,	\$25.09	\$158,618
1000000001001011	2017	UBM, Clay Cap, FA, Run on/off, PCM,	\$25.86	\$162,770
1000000001001110	2018	UBM, Clay Cap, FA, Dust, Run on/off,	\$26.13	\$159,981
1000000010000011	2019	UBM, Synth Cap, Run on/off, PCM,	\$23.78	\$147,554
1000000010000111	2020	UBM, Synth Cap, Dust, Run on/off, PCM,	\$24.06	\$147,767
1000000010001011	2021	UBM, Synth Cap, FA, Run on/off, PCM,	\$25.15	\$159,669
1000000010001101	2022	UBM, Synth Cap, FA, Dust, PCM,	\$25.35	\$152,444
1000000010001111	2023	UBM, Synth Cap, FA, Dust, Run on/off, PCM,	\$25.42	\$159,883
1000000100000000	2024	UBM, LCS,	\$29.50	\$186,022
1000000100001100	2025	UBM, LCS, FA, Dust,	\$31.13	\$198,351
1000000100010000	2026	UBM, LCS, Soil Cap,	\$30.30	\$190,272
1000000100010000a	2026a	UBM, LCS, Soil Cap (cap cost accrues after closure)	\$29.57	\$186,476
1000000100011010	2027	UBM, LCS, Soil Cap, FA, Run on/off,	\$31.72	\$209,826
1000000100011011	2028	UBM, LCS, Soil Cap, FA, Run on/off, PCM,	\$31.73	\$212,829
1000000100011111	2029	UBM, LCS, Soil Cap, FA, Dust, Run on/off, PCM,	\$32.01	\$213,042
1000000100100000	2030	UBM, LCS, Ash Cap,	\$30.45	\$192,000
1000000101001110	2031	UBM, LCS, Clay Cap, FA, Dust, Run on/off,	\$33.04	\$214,404
1000000101001111	2032	UBM, LCS, Clay Cap, FA, Dust, Run on/off, PCM,	\$33.05	\$217,407
1000000110000011	2033	UBM, LCS, Synth Cap, Run on/off, PCM,	\$30.70	\$201,977
1000000110000111	2034	UBM, LCS, Synth Cap, Dust, Run on/off, PCM,	\$30.97	\$202,191
1000000110001001	2035	UBM, LCS, Synth Cap, FA, PCM,	\$31.99	\$206,654
1000000110001011	2036	UBM, LCS, Synth Cap, FA, Run on/off, PCM,	\$32.06	\$214,093
1000000110001101	2037	UBM, LCS, Synth Cap, FA, Dust, PCM,	\$32.27	\$206,867
1000000110001111	2038	UBM, LCS, Synth Cap, FA, Dust, Run on/off, PCM,	\$32.33	\$214,306
1001000000011011	2039	UBM, Clay Liner, Soil Cap, FA, Run on/off, PCM,	\$45.69	\$244,463
1001000000011111	2040	UBM, Clay Liner, Soil Cap, FA, Dust, Run on/off, PCM,	\$45.97	\$244,677
1001000001001110	2041	UBM, Clay Liner, Clay Cap, FA, Dust, Run	\$47.00	\$246,039

Exhibit D-1 Combination Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
		on/off,		
1001000010001011	2042	UBM, Clay Liner, Synth Cap, FA, Run on/off, PCM,	\$46.02	\$245,728
1001000010001101	2043	UBM, Clay Liner, Synth Cap, FA, Dust, PCM,	\$46.23	\$238,502
1001000010001111	2044	UBM, Clay Liner, Synth Cap, FA, Dust, Run on/off, PCM,	\$46.29	\$245,941
1001000100000000	2045	UBM, Clay Liner, LCS,	\$50.38	\$272,080
1001000100011010	2046	UBM, Clay Liner, LCS, Soil Cap, FA, Run on/off,	\$52.60	\$295,884
1001000100011011	2047	UBM, Clay Liner, LCS, Soil Cap, FA, Run on/off, PCM,	\$52.61	\$298,887
1001000100011111	2048	UBM, Clay Liner, LCS, Soil Cap, FA, Dust, Run on/off, PCM,	\$52.88	\$299,100
1001000100100000	2049	UBM, Clay Liner, LCS, Ash Cap,	\$51.32	\$278,058
1001000101000000	2050	UBM, Clay Liner, LCS, Clay Cap,	\$52.22	\$280,694
1001000101000011	2051	UBM, Clay Liner, LCS, Clay Cap, Run on/off, PCM,	\$52.29	\$291,136
1001000110000000	2052	UBM, Clay Liner, LCS, Synth Cap,	\$51.50	\$277,594
1001000110000111	2053	UBM, Clay Liner, LCS, Synth Cap, Dust, Run on/off, PCM,	\$51.85	\$288,249
1001000110001001	2054	UBM, Clay Liner, LCS, Synth Cap, FA, PCM,	\$52.87	\$292,712
1001000110001011	2055	UBM, Clay Liner, LCS, Synth Cap, FA, Run on/off, PCM,	\$52.94	\$300,151
1001000110001111	2056	UBM, Clay Liner, LCS, Synth Cap, FA, Dust, Run on/off, PCM,	\$53.21	\$300,365
1010000000011011	2057	UBM, Synth Liner, Soil Cap, FA, Run on/off, PCM,	\$50.89	\$275,798
1010000000011111	2058	UBM, Synth Liner, Soil Cap, FA, Dust, Run on/off, PCM,	\$51.16	\$276,012
1010000001001110	2059	UBM, Synth Liner, Clay Cap, FA, Dust, Run on/off,	\$52.20	\$277,374
1010000010001011	2060	UBM, Synth Liner, Synth Cap, FA, Run on/off, PCM,	\$51.22	\$277,063
1010000010001101	2061	UBM, Synth Liner, Synth Cap, FA, Dust, PCM,	\$51.42	\$269,837
1010000010001111	2062	UBM, Synth Liner, Synth Cap, FA, Dust, Run on/off, PCM,	\$51.49	\$277,276
1010000100010000	2063	UBM, Synth Liner, LCS, Soil Cap,	\$56.37	\$307,665
1010000100010000a	2063a	UBM, Synth Liner, LCS, Soil Cap (cap cost accrues after closure)	\$55.63	\$303,869
1010000100100000	2064	UBM, Synth Liner, LCS, Ash Cap,	\$56.52	\$309,393
1001000110000011	2065	UBM, Clay Liner, LCS, Synth Cap, Run on/off, PCM,	\$51.58	\$288,035

Exhibit D-1 Combination Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
1000000101000011	2066	UBM, LCS, Clay Cap, Run on/off, PCM,	\$31.42	\$205,078
1000000101000000	2067	UBM, LCS, Clay Cap,	\$31.34	\$194,636
1001000000100000	2068	UBM, Clay Liner, Ash Cap,	\$44.41	\$223,634
1001000000011100	2069	UBM, Clay Liner, Soil Cap, FA, Dust,	\$45.89	\$234,235
0000000101000011	2070	LCS, Clay Cap, Run on/off, PCM,	\$31.32	\$151,641
1000000110000000	2071	UBM, LCS, Synth Cap,	\$30.62	\$191,536
0000000101000000	2072	LCS, Clay Cap,	\$31.24	\$141,199
0000000101000000a	2072a	LCS, Clay Cap (cap cost accrues after closure)	\$29.53	\$133,262
1010000100001111	2073	UBM, Synth Liner, LCS, FA, Dust, Run on/off, PCM,	\$57.28	\$326,186
1000000000001111	2074	UBM, FA, Dust, Run on/off, PCM,	\$24.30	\$154,369
1000000100001111	2075	UBM, LCS, FA, Dust, Run on/off, PCM,	\$31.21	\$208,793
1001000100001111	2076	UBM, Clay Liner, LCS, FA, Dust, Run on/off, PCM,	\$52.09	\$294,851
1001000100001110	2077	UBM, Clay Liner, LCS, FA, Dust, Run on/off,	\$52.08	\$291,849
1010000100001110	2078	UBM, Synth Liner, LCS, FA, Dust, Run on/off,	\$57.27	\$323,184
1000000100001110	2079	UBM, LCS, FA, Dust, Run on/off,	\$31.20	\$205,790
1001000000001111	2080	UBM, Clay Liner, FA, Dust, Run on/off, PCM,	\$45.17	\$240,427
0000000000000011	2081	Run on/off, PCM,	\$22.56	\$88,603
0000000100000011	2082	LCS, Run on/off, PCM,	\$29.48	\$143,027
0010000100000011	2083	Synth Liner, LCS, Run on/off, PCM,	\$55.55	\$260,420
0001000100000011	2084	Clay Liner, LCS, Run on/off, PCM,	\$50.36	\$229,085
1010000100001011	2085	UBM, Synth Liner, LCS, FA, Run on/off, PCM,	\$57.01	\$325,973
1000000100001000	2086	UBM, LCS, FA,	\$30.86	\$198,138
1000000000001000	2087	UBM, FA,	\$23.95	\$143,714
1010000000001000	2088	UBM, Synth Liner, FA,	\$50.02	\$261,108
1001000000001000	2089	UBM, Clay Liner, FA,	\$44.82	\$229,773
1010000100001000	2090	UBM, Synth Liner, LCS, FA,	\$56.93	\$315,531
1001000100001000	2091	UBM, Clay Liner, LCS, FA,	\$51.74	\$284,196
0000000110000011	2092	LCS, Synth Cap, Run on/off, PCM,	\$30.60	\$148,540
0001000110000011	2093	Clay Liner, LCS, Synth Cap, Run on/off, PCM,	\$51.48	\$234,599
0001000110000011a	2093a	Clay Liner, LCS, Synth Cap, Run on/off, PCM, (cap and PCM costs accrue after closure)	\$50.47	\$229,736
0010000110000011	2094	Synth Liner, LCS, Synth Cap, Run on/off, PCM,	\$56.67	\$265,934
1000000101001101	2095	UBM, LCS, Clay Cap, FA, Dust, PCM,	\$32.99	\$209,968
1010000101001101	2096	UBM, Synth Liner, LCS, Clay Cap, FA, Dust, PCM,	\$59.06	\$327,361
1001000101001101	2097	UBM, Clay Liner, LCS, Clay Cap, FA, Dust,	\$53.86	\$296,026

Exhibit D-1 Combination Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
		PCM,		
1000000001001101	2098	UBM, Clay Cap, FA, Dust, PCM,	\$26.07	\$155,544
1010000001001101	2099	UBM, Synth Liner, Clay Cap, FA, Dust, PCM,	\$52.14	\$272,938
0010000101001111	2100	Synth Liner, LCS, Clay Cap, FA, Dust, Run on/off, PCM,	\$59.02	\$281,363
1000000000001110	2101	UBM, FA, Dust, Run on/off,	\$24.28	\$151,367
1010000000001111	2102	UBM, Synth Liner, FA, Dust, Run on/off, PCM,	\$50.37	\$271,762
1001000000001111	2103	UBM, Clay Liner, FA, Dust, Run on/off, PCM,	\$45.17	\$240,427
0000000100001110	2104	LCS, FA, Dust, Run on/off,	\$31.10	\$152,353
0010000100001110	2105	Synth Liner, LCS, FA, Dust, Run on/off,	\$57.17	\$269,747
0001000100001110	2106	Clay Liner, LCS, FA, Dust, Run on/off,	\$51.98	\$238,412
0000000000001110	2107	FA, Dust, Run on/off,	\$24.19	\$97,930
0010000000001110	2108	Synth Liner, FA, Dust, Run on/off,	\$50.26	\$215,323
0001000000001110	2109	Clay Liner, FA, Dust, Run on/off,	\$45.06	\$183,988
1010000000001110	2110	UBM, Synth Liner, FA, Dust, Run on/off,	\$50.36	\$268,760
1001000000001110	2111	UBM, Clay Liner, FA, Dust, Run on/off,	\$45.16	\$237,425
1000000000001001	2112	UBM, FA, PCM,	\$23.96	\$146,717
1010000000001001	2113	UBM, Synth Liner, FA, PCM,	\$50.03	\$264,110
1001000000001001	2114	UBM, Clay Liner, FA, PCM,	\$44.83	\$232,775
1000000100001001	2115	UBM, LCS, FA, PCM,	\$30.87	\$201,140
1010000100001001	2116	UBM, Synth Liner, LCS, FA, PCM,	\$56.94	\$318,534
1001000100001001	2117	UBM, Clay Liner, LCS, FA, PCM,	\$51.75	\$287,198
0000000100000001	2118	LCS, PCM,	\$29.41	\$135,588
0010000100000001	2119	Synth Liner, LCS, PCM,	\$55.48	\$252,981
0001000100000001	2120	Clay Liner, LCS, PCM,	\$50.29	\$221,646
1000000100001101	2121	UBM, LCS, FA, Dust, PCM,	\$31.15	\$201,354
1010000100001101	2122	UBM, Synth Liner, LCS, FA, Dust, PCM,	\$57.22	\$318,747
1001000100001101	2123	UBM, Clay Liner, LCS, FA, Dust, PCM,	\$52.02	\$287,412
1000000000001011	2124	UBM, FA, Run on/off, PCM,	\$24.02	\$154,156
1010000000001011	2125	UBM, Synth Liner, FA, Run on/off, PCM,	\$50.09	\$271,549
1001000000001011	2126	UBM, Clay Liner, FA, Run on/off, PCM,	\$44.90	\$240,214
1000000100001011	2127	UBM, LCS, FA, Run on/off, PCM,	\$30.94	\$208,579
1010000100001011	2128	UBM, Synth Liner, LCS, FA, Run on/off, PCM,	\$57.01	\$325,973
1001000100001011	2129	UBM, Clay Liner, LCS, FA, Run on/off, PCM,	\$51.81	\$294,637
1010000000001101	2130	UBM, Synth Liner, FA, Dust, PCM,	\$50.30	\$264,324
1001000000001101	2131	UBM, Clay Liner, Dust, Run on/off,	\$43.80	\$225,309
1001000000001101	2132	UBM, Clay Liner, FA, Dust, PCM,	\$45.11	\$232,988

Exhibit D-1 Combination Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
1000000001001000	2133	UBM, Clay Cap, FA,	\$25.79	\$152,328
1010000001001000	2134	UBM, Synth Liner, Clay Cap, FA,	\$51.86	\$269,722
1001000001001000	2135	UBM, Clay Liner, Clay Cap, FA,	\$46.66	\$238,387
0001000110000000	2136	Clay Liner, LCS, Synth Cap,	\$51.40	\$224,157
0000000100010000	2137	LCS, Soil Cap,	\$30.20	\$136,835
0000000100010000a	2137a	LCS, Soil Cap (cap cost accrues after closure)	\$29.47	\$133,038
0000000000011110	2138	Soil Cap, FA, Dust, Run on/off,	\$24.98	\$102,179
0010000000011110	2139	Synth Liner, Soil Cap, FA, Dust, Run on/off,	\$51.05	\$219,573
0001000000011110	2140	Clay Liner, Soil Cap, FA, Dust, Run on/off,	\$45.86	\$188,237
0000000100011110	2141	LCS, Soil Cap, FA, Dust, Run on/off,	\$31.90	\$156,603
0010000100011110	2142	Synth Liner, LCS, Soil Cap, FA, Dust, Run on/off,	\$57.97	\$273,996
0001000100011110	2143	Clay Liner, LCS, Soil Cap, FA, Dust, Run on/off,	\$52.77	\$242,661
1000000000011001	2144	UBM, Soil Cap, FA, PCM,	\$24.75	\$150,966
1010000000011001	2145	UBM, Synth Liner, Soil Cap, FA, PCM,	\$50.82	\$268,359
1001000000011001	2146	UBM, Clay Liner, Soil Cap, FA, PCM,	\$45.63	\$237,024
1000000100011001	2147	UBM, LCS, Soil Cap, FA, PCM,	\$31.67	\$205,390
1010000100011001	2148	UBM, Synth Liner, LCS, Soil Cap, FA, PCM,	\$57.74	\$322,783
1001000100011001	2149	UBM, Clay Liner, LCS, Soil Cap, FA, PCM,	\$52.54	\$291,448
0010000100010000	2150	Synth Liner, LCS, Soil Cap,	\$56.27	\$254,228
0010000110001000	2151	Synth Liner, LCS, Synth Cap, FA,	\$57.96	\$267,608
0010000110001011	2152	Synth Liner, LCS, Synth Cap, FA, Run on/off, PCM,	\$58.03	\$278,049
0010000110001111	2153	Synth Liner, LCS, Synth Cap, FA, Dust, Run on/off, PCM,	\$58.31	\$278,263
1010000101001000	2154	UBM, Synth Liner, LCS, Clay Cap, FA,	\$58.77	\$324,145
1010000110001000	2155	UBM, Synth Liner, LCS, Synth Cap, FA,	\$58.05	\$321,045
1000010110001111	10001	UBM, Yes Liner, LCS, Synth Cap, FA, Dust, Run on/off, PCM,	\$55.99	\$317,193
1000010110001101	10002	UBM, Yes Liner, LCS, Synth Cap, FA, Dust, PCM,	\$55.92	\$309,755
1000010110001011	10003	UBM, Yes Liner, LCS, Synth Cap, FA, Run on/off, PCM,	\$55.72	\$316,979
1000010110001001	10004	UBM, Yes Liner, LCS, Synth Cap, FA, PCM,	\$55.65	\$309,540
1000010110000111	10005	UBM, Yes Liner, LCS, Synth Cap, Dust, Run on/off, PCM,	\$54.63	\$305,077
1000010110000011	10006	UBM, Yes Liner, LCS, Synth Cap, Run on/off, PCM,	\$54.36	\$304,864
1000010110000000	10007	UBM, Yes Liner, LCS, Synth Cap,	\$54.29	\$294,422
1000010101001111	10008	UBM, Yes Liner, LCS, Clay Cap, FA, Dust, Run on/off, PCM,	\$56.71	\$320,294
1000010101001110	10009	UBM, Yes Liner, LCS, Clay Cap, FA, Dust, Run on/off,	\$56.71	\$317,291

Exhibit D-1 Combination Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
1000010101000011	10010	UBM, Yes Liner, LCS, Clay Cap, Run on/off, PCM,	\$55.08	\$307,964
1000010101000000	10011	UBM, Yes Liner, LCS, Clay Cap,	\$55.01	\$297,522
1000010100100000	10012	UBM, Yes Liner, LCS, Ash Cap,	\$54.11	\$294,886
1000010100011111	10013	UBM, Yes Liner, LCS, Soil Cap, FA, Dust, Run on/off, PCM,	\$55.67	\$315,929
1000010100011011	10014	UBM, Yes Liner, LCS, Soil Cap, FA, Run on/off, PCM,	\$55.40	\$315,715
1000010100011010	10015	UBM, Yes Liner, LCS, Soil Cap, FA, Run on/off,	\$55.39	\$312,712
1000010100010000	10016	UBM, Yes Liner, LCS, Soil Cap,	\$53.96	\$293,158
1000010100010000a	10016a	UBM, Yes Liner, LCS, Soil Cap (cap cost accrues after closure)	\$53.23	\$289,362
1000010100001111	10017	UBM, Yes Liner, LCS, FA, Dust, Run on/off, PCM,	\$54.88	\$311,679
1000010100001110	10018	UBM, Yes Liner, LCS, FA, Dust, Run on/off,	\$54.87	\$308,677
1000010100000000	10019	UBM, Yes Liner, LCS,	\$53.17	\$288,909
1000010010001111	10020	UBM, Yes Liner, Synth Cap, FA, Dust, Run on/off, PCM,	\$49.08	\$262,769
1000010010001101	10021	UBM, Yes Liner, Synth Cap, FA, Dust, PCM,	\$49.02	\$255,330
1000010010001011	10022	UBM, Yes Liner, Synth Cap, FA, Run on/off, PCM,	\$48.81	\$262,556
1000010010001001	10023	UBM, Yes Liner, Synth Cap, FA, PCM,	\$48.73	\$255,117
1000010001001111	10024	UBM, Yes Liner, Clay Cap, FA, Dust, Run on/off, PCM,	\$49.79	\$265,870
1000010001001110	10025	UBM, Yes Liner, Clay Cap, FA, Dust, Run on/off,	\$49.79	\$262,867
1000010001000011	10026	UBM, Yes Liner, Clay Cap, Run on/off, PCM,	\$48.16	\$253,541
1000010001000000	10027	UBM, Yes Liner, Clay Cap,	\$48.09	\$243,099
1000010000100000	10028	UBM, Yes Liner, Ash Cap,	\$47.20	\$240,462
1000010000011111	10029	UBM, Yes Liner, Soil Cap, FA, Dust, Run on/off, PCM,	\$48.76	\$261,505
1000010000011100	10030	UBM, Yes Liner, Soil Cap, FA, Dust,	\$48.68	\$251,064
1000010000011011	10031	UBM, Yes Liner, Soil Cap, FA, Run on/off, PCM,	\$48.48	\$261,291
1000010000010000	10032	UBM, Yes Liner, Soil Cap,	\$47.05	\$238,734
1000010000000000	10033	UBM, Yes Liner,	\$46.25	\$234,485
0000010110001001	10034	Yes Liner, LCS, Synth Cap, FA, PCM,	\$55.56	\$256,103
0000010101000011	10035	Yes Liner, LCS, Clay Cap, Run on/off, PCM,	\$54.99	\$254,527
0000010101000000	10036	Yes Liner, LCS, Clay Cap,	\$54.91	\$244,086
0000010101000000a	10036a	Yes Liner, LCS, Clay Cap (cap cost accrues after closure)	\$53.20	\$236,149
0000010100011001	10037	Yes Liner, LCS, Soil Cap, FA, PCM,	\$55.24	\$254,839
0000010100000011	10038	Yes Liner, LCS, Run on/off, PCM,	\$53.15	\$245,913
0000010100000000	10039	Yes Liner, LCS,	\$53.07	\$235,472
0000010010001001	10040	Yes Liner, Synth Cap, FA, PCM,	\$48.65	\$201,680

Exhibit D-1 Combination Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
0000010001000000	10041	Yes Liner, Clay Cap,	\$47.99	\$189,662
0000010000010000	10042	Yes Liner, Soil Cap,	\$46.95	\$185,297
0000010000000100	10043	Yes Liner, Dust,	\$46.42	\$181,262
0000010000000000	10044	Yes Liner,	\$46.15	\$181,048
1000010000001000	10045	UBM, Yes Liner, FA,	\$47.61	\$246,601
1000010100001000	10046	UBM, Yes Liner, LCS, FA,	\$54.53	\$301,024
0000010110000011	10047	Yes Liner, LCS, Synth Cap, Run on/off, PCM,	\$54.27	\$251,427
0000010110000011a	10047a	Yes Liner, LCS, Synth Cap, Run on/off, PCM (cap and PCM costs accrues after closure)	\$53.26	\$246,564
1000010101001101	10048	UBM, Yes Liner, LCS, Clay Cap, FA, Dust, PCM,	\$56.65	\$312,854
1000010001001101	10049	UBM, Yes Liner, Clay Cap, FA, Dust, PCM,	\$49.74	\$258,431
1000010000001111	10050	UBM, Yes Liner, FA, Dust, Run on/off, PCM,	\$47.96	\$257,255
0000010100001110	10051	Yes Liner, LCS, FA, Dust, Run on/off,	\$54.77	\$255,240
1000010000001110	10052	UBM, Yes Liner, FA, Dust, Run on/off,	\$47.95	\$254,253
1000010100001001	10053	UBM, Yes Liner, LCS, FA, PCM,	\$54.54	\$304,027
0000010100000001	10054	Yes Liner, LCS, PCM,	\$53.08	\$238,474
0000010100000001a	10054a	Yes Liner, LCS, PCM (PCM cost accrues after closure)	\$53.08	\$238,474
1000010100001101	10055	UBM, Yes Liner, LCS, FA, Dust, PCM,	\$54.81	\$304,240
1000010000001011	10056	UBM, Yes Liner, FA, Run on/off, PCM,	\$47.69	\$257,042
1000010100001011	10057	UBM, Yes Liner, LCS, FA, Run on/off, PCM,	\$54.60	\$311,466
1000010000001101	10058	UBM, Yes Liner, FA, Dust, PCM,	\$47.90	\$249,817
0000010100011110	10059	Yes Liner, LCS, Soil Cap, FA, Dust, Run on/off,	\$55.56	\$259,489
1000010100011001	10060	UBM, Yes Liner, LCS, Soil Cap, FA, PCM,	\$55.33	\$308,276
1000001110001111	11001	UBM, Unknown Liner, LCS, Synth Cap, FA, Dust, Run on/off, PCM,	\$35.92	\$225,308
1000001110001101	11002	UBM, Unknown Liner, LCS, Synth Cap, FA, Dust, PCM,	\$35.86	\$218,333
1000001110001011	11003	UBM, Unknown Liner, LCS, Synth Cap, FA, Run on/off, PCM,	\$35.66	\$225,108
1000001110001001	11004	UBM, Unknown Liner, LCS, Synth Cap, FA, PCM,	\$35.60	\$218,133
1000001110000111	11005	UBM, Unknown Liner, LCS, Synth Cap, Dust, Run on/off, PCM,	\$34.64	\$213,948
1000001110000011	11006	UBM, Unknown Liner, LCS, Synth Cap, Run on/off, PCM,	\$34.39	\$213,748
1000001110000000	11007	UBM, Unknown Liner, LCS, Synth Cap,	\$34.32	\$203,957
1000001101001111	11008	UBM, Unknown Liner, LCS, Clay Cap, FA, Dust, Run on/off, PCM,	\$36.59	\$228,215
1000001101001110	11009	UBM, Unknown Liner, LCS, Clay Cap, FA, Dust, Run on/off,	\$36.59	\$225,400
1000001101000011	11010	UBM, Unknown Liner, LCS, Clay Cap, Run on/off,	\$35.06	\$216,655

Exhibit D-1 Combination Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
		PCM,		
1000001101000000	11011	UBM, Unknown Liner, LCS, Clay Cap,	\$34.99	\$206,864
1000001100100000	11012	UBM, Unknown Liner, LCS, Ash Cap,	\$34.15	\$204,393
1000001100011111	11013	UBM, Unknown Liner, LCS, Soil Cap, FA, Dust, Run on/off, PCM,	\$35.61	\$224,122
1000001100011011	11014	UBM, Unknown Liner, LCS, Soil Cap, FA, Run on/off, PCM,	\$35.36	\$223,922
1000001100011010	11015	UBM, Unknown Liner, LCS, Soil Cap, FA, Run on/off,	\$35.35	\$221,107
1000001100010000	11016	UBM, Unknown Liner, LCS, Soil Cap,	\$34.01	\$202,772
1000001100001111	11017	UBM, Unknown Liner, LCS, FA, Dust, Run on/off, PCM,	\$34.87	\$220,138
1000001100001110	11018	UBM, Unknown Liner, LCS, FA, Dust, Run on/off,	\$34.86	\$217,323
1000001100000000	11019	UBM, Unknown Liner, LCS,	\$33.27	\$198,788
1000001010001111	11020	UBM, Unknown Liner, Synth Cap, FA, Dust, Run on/off, PCM,	\$29.44	\$174,279
1000001010001101	11021	UBM, Unknown Liner, Synth Cap, FA, Dust, PCM,	\$29.38	\$167,304
1000001010001011	11022	UBM, Unknown Liner, Synth Cap, FA, Run on/off, PCM,	\$29.18	\$174,079
1000001010001001	11023	UBM, Unknown Liner, Synth Cap, FA, PCM,	\$29.11	\$167,104
1000001001001111	11024	UBM, Unknown Liner, Clay Cap, FA, Dust, Run on/off, PCM,	\$30.11	\$177,187
1000001001001110	11025	UBM, Unknown Liner, Clay Cap, FA, Dust, Run on/off,	\$30.10	\$174,371
1000001001000011	11026	UBM, Unknown Liner, Clay Cap, Run on/off, PCM,	\$28.58	\$165,626
1000001001000000	11027	UBM, Unknown Liner, Clay Cap,	\$28.51	\$155,836
1000001000100000	11028	UBM, Unknown Liner, Ash Cap,	\$27.67	\$153,363
1000001000011111	11029	UBM, Unknown Liner, Soil Cap, FA, Dust, Run on/off, PCM,	\$29.13	\$173,093
1000001000011100	11030	UBM, Unknown Liner, Soil Cap, FA, Dust,	\$29.06	\$163,304
1000001000011011	11031	UBM, Unknown Liner, Soil Cap, FA, Run on/off, PCM,	\$28.88	\$172,893
1000001000010000	11032	UBM, Unknown Liner, Soil Cap,	\$27.53	\$151,743
1000001000000000	11033	UBM, Unknown Liner,	\$26.78	\$147,759
0000001110001001	11034	Unknown Liner, LCS, Synth Cap, FA, PCM,	\$35.51	\$168,029
0000001101000011	11035	Unknown Liner, LCS, Clay Cap, Run on/off, PCM,	\$34.97	\$166,551
0000001101000000	11036	Unknown Liner, LCS, Clay Cap,	\$34.90	\$156,761
0000001100011001	11037	Unknown Liner, LCS, Soil Cap, FA, PCM,	\$35.21	\$166,843
0000001100000011	11038	Unknown Liner, LCS, Run on/off, PCM,	\$33.25	\$158,474
0000001100000000	11039	Unknown Liner, LCS,	\$33.17	\$148,684
0000001010001001	11040	Unknown Liner, Synth Cap, FA, PCM,	\$29.02	\$117,000

Exhibit D-1 Combination Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
0000001001000000	11041	Unknown Liner, Clay Cap,	\$28.42	\$105,731
0000001000010000	11042	Unknown Liner, Soil Cap,	\$27.44	\$101,639
0000001000000100	11043	Unknown Liner, Dust,	\$26.94	\$97,856
0000001000000000	11044	Unknown Liner,	\$26.69	\$97,655
1000001000001000	11045	UBM, Unknown Liner, FA,	\$28.06	\$159,119
1000001000001111	11046	UBM, Unknown Liner, FA, Dust, Run on/off, PCM,	\$28.39	\$169,109
0000001100001110	11047	Unknown Liner, LCS, FA, Dust, Run on/off,	\$34.77	\$167,219
0000001000001110	11048	Unknown Liner, FA, Dust, Run on/off,	\$28.28	\$116,190
1000001100001000	11049	UBM, Unknown Liner, LCS, FA,	\$34.54	\$210,148
1000001000001001	11050	UBM, Unknown Liner, FA, PCM,	\$28.07	\$161,934
1000001000001011	11051	UBM, Unknown Liner, FA, Run on/off, PCM,	\$28.13	\$168,909
1000001001001000	11052	UBM, Unknown Liner, Clay Cap, FA,	\$29.78	\$167,195
0000001000011110	11053	Unknown Liner, Soil Cap, FA, Dust, Run on/off,	\$29.03	\$120,174
1000001000011001	11054	UBM, Unknown Liner, Soil Cap, FA, PCM,	\$28.81	\$165,918

Exhibit D-2 Pile Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Pile Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
0000000000000000	1010	No Controls	\$5.66	\$80,590
1001000101001111	1002	UBM, Clay Liner, LCS, Clay Cap, FA, Dust, Run-on/off, PCM	\$52.26	\$218,927
1000000001000000	1004	UBM, Clay Cap	\$8.53	\$145,334
0000100000010000	1005	Ash Liner, Soil Cap	\$14.40	\$98,888
1001000101001110	1006	UBM, Clay Liner, LCS, Clay Cap, FA, Dust, Run-on/off	\$52.25	\$215,621
1001000001001101	1012	UBM, Clay Liner, Clay Cap, FA, Dust, PCM	\$41.90	\$176,196
1010000110000000	1015	UBM, Liner, LCS, Cap	\$56.47	\$211,684
0110000110000000	1016	150M Mon, Liner, LCS, Cap	\$56.46	\$235,263
0110000110001001	1018	150M Mon, Liner, LCS, Cap, FA, PCM	\$58.57	\$248,227
1001000110001101	1019	UBM, Clay Liner, LCS, Cap, FA, Dust, PCM	\$51.09	\$208,277
1010000110001111	1022	UBM, Liner, LCS, Cap, FA, Dust, Run-on/off, PCM	\$58.93	\$234,229
0000000000011001	1025	Soil Cap, FA, PCM	\$8.95	\$95,462
1010000110001101	1027	UBM, Liner, LCS, Cap, FA, Dust, PCM	\$58.84	\$224,729
1000000000001101	1028	UBM, FA, Dust, PCM	\$8.16	\$155,055
1000000000000000	1029	UBM	\$5.78	\$141,863
1001000001001111	1030	UBM, Clay Liner, Clay Cap, FA, Dust, Run-on/off, PCM	\$41.99	\$185,694
1000000000000001	1031	UBM, PCM	\$5.79	\$145,315
1000000010001001	1032	UBM, Cap, FA, PCM	\$9.55	\$157,145
1010000101001110	1033	UBM, Liner, LCS, Clay Cap, FA, Dust, Run-on/off	\$59.99	\$231,928
0101000000010001	1034	150M Mon, Clay Liner, Soil Cap, PCM	\$37.98	\$188,619
1001000010001001	1036	UBM, Clay Liner, Cap, FA, PCM	\$40.55	\$174,815
1000000000100000	1037	UBM, Ash Cap	\$7.20	\$145,300
0100000000000001	1038	150M Mon, PCM	\$5.79	\$169,040
0110000110000001	1039	150M Mon, Liner, LCS, Cap, PCM	\$56.48	\$238,715
1000000001000001	1040	UBM, Clay/Soil Cap, PCM (uncompacted)	\$7.14	\$120,133
0001000001000000	1041	Clay Liner, Clay Cap	\$39.41	\$101,731
0001000001000000a	1041a	Clay Liner, Clay Cap (cap cost accrues after closure)	\$36.86	\$98,643
0100000001000001	1042	150M Mon, Clay/Soil Cap, PCM (uncompacted)	\$7.14	\$145,127
1010000000100000	1043	UBM, Liner, Ash Cap	\$45.95	\$179,423
1001000100010000	1044	UBM, Clay Liner, LCS, Soil Cap	\$48.25	\$194,820
1010000000011100	1046	UBM, Liner, Soil Cap, FA, Dust	\$48.09	\$187,634
1010000110001001	1047	UBM, Liner, LCS, Cap, FA, PCM	\$58.57	\$224,501
1000000000011100	1048	UBM, Soil Cap, FA, Dust	\$9.33	\$153,511
0100000010001001	1049	150M Mon, Cap, FA, PCM (compacted)	\$9.55	\$180,871
0010000000000000	1053	Liner	\$44.41	\$114,713
0000000010001001	1059	Cap, PCM, FA	\$9.43	\$95,872

Exhibit D-2 Pile Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Pile Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
1010000101000111	1060	UBM, Liner, LCS, Clay Cap, Dust, Run-on/off, PCM	\$57.90	\$225,868
1001000000010000	1062	UBM, Clay Liner, Soil Cap	\$37.98	\$161,441
0101000001000000	1063	150M Mon, Clay Liner, Clay Cap	\$39.53	\$186,730
0101000000010000	1064	150M Mon, Clay Liner, Soil Cap	\$37.97	\$185,167
0100000001000000	1065	150M Mon, Clay/Soil Cap	\$7.13	\$140,247
0010000110000000	1066	Liner, LCS, Cap	\$56.35	\$150,370
0110000100000000	1067	150M Mon, Liner, LCS	\$54.80	\$233,048
0100000010001111	1070	150M Mon, Cap, FA, Dust, Run-on/off, PCM	\$9.88	\$190,424
1000000010000001	1074	UBM, Cap, PCM	\$7.45	\$147,634
0101000010000001	1075	150M Mon, Clay Liner, Cap, PCM	\$38.45	\$189,030
0100000010000001	1077	150M Mon, Cap, PCM	\$7.45	\$171,360
1010000101001111	1078	UBM, Liner, LCS, Clay Cap, FA, Dust, Run-on/off, PCM	\$60.00	\$235,380
1000000001001111	1079	UBM, Clay Cap, FA, Dust, Run-on/off, PCM	\$10.99	\$168,024
0101000010001001	1083	150M Mon, Clay Liner, Cap, FA, PCM	\$40.55	\$198,541
1010000000000000	1085	UBM, Liner	\$44.53	\$175,986
1010000000000001	1087	UBM, Liner, PCM	\$44.54	\$179,437
1010000100000000	1088	UBM, Liner, LCS	\$54.80	\$209,365
1001000000000000	1089	UBM, Clay Liner	\$36.79	\$159,533
1000000010000000	1090	UBM, Cap	\$7.45	\$144,183
1000000000001100	1091	UBM, FA, Dust	\$8.15	\$151,603
1000000000010000	1092	UBM, Soil Cap	\$6.97	\$143,771
1000100000010000	1093	UBM, Ash Liner, Soil Cap	\$14.52	\$160,160
1001000001000000	1094	UBM, Clay Liner, Clay Cap	\$39.53	\$163,004
1010000000010000	1095	UBM, Liner, Soil Cap	\$45.72	\$177,894
0001000000000000	1098	Clay Liner	\$36.67	\$98,260
0000000001000000	1099	Clay Cap	\$8.41	\$84,061
1010000110000110	1100	UBM, Liner, LCS, Cap, Dust, Run-on/off	\$56.82	\$221,265
1000000001000111	1101	UBM, Clay Cap, Dust, Run-on/off, PCM	\$8.89	\$158,513
1000000000000100	1104	UBM, Dust	\$6.05	\$142,092
0010000100000000	1105	Liner, LCS	\$54.68	\$147,946
0010000110000010	1106	Liner, LCS, Cap, Run-on/off	\$56.43	\$159,764
1010000110000010	1107	UBM, Liner, LCS, Cap, Run-on/off	\$56.55	\$221,037
0010000100000100	1108	Liner, LCS, Dust	\$54.95	\$148,175
0000000000000010	1109	Run-on/off	\$5.75	\$90,089
0000000001000010	1110	Clay Cap, Run-on/off	\$8.49	\$93,559
1000000001000010	1111	UBM, Clay Cap, Run-on/off	\$8.61	\$154,832
0000000001000000	1112	Cap	\$7.33	\$82,910

Exhibit D-2 Pile Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Pile Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
0000000000100000	1113	Ash Cap	\$7.08	\$84,027
0001000010000000	1114	Clay Liner, Cap	\$38.33	\$100,580
1001000010000000	1115	UBM, Clay Liner, Cap	\$38.45	\$161,853
0000000000010000	1116	Soil Cap	\$6.85	\$82,498
0000000000010000a	1116a	Soil Cap (cap cost accrues after closure)	\$5.76	\$80,947
0010000001000000	1117	Liner, Clay Cap	\$47.15	\$118,184
0010000101000000	1118	Liner, LCS, Clay Cap	\$57.42	\$151,417
0010000101000000a	1118a	Liner, LCS, Clay Cap (cap cost accrues after closure)	\$54.87	\$148,329
0000000000000100	1119	Dust	\$5.94	\$80,819
0000000000000110	1120	Dust, Run-on/Off	\$6.02	\$90,317
0000000001000110	1121	Clay Cap, Dust, Run-on/off	\$8.76	\$93,788
1000000001000110	1122	UBM, Clay Cap, Dust, Run-on/off	\$8.89	\$155,061
0000000000000001	1123	PCM with Construction	\$5.67	\$84,042
1000000001000011	1124	UBM, Clay Cap, Run-on/off, PCM	\$8.61	\$158,284
0000000000010001	1125	Soil Cap, PCM	\$6.86	\$85,950
1010000110000011	1126	UBM, Liner, LCS, Cap, Run-on/off, PCM	\$56.56	\$224,489
0010000100000010	1127	Liner, LCS, Run-on/off	\$54.77	\$157,444
1010000110000111	1128	UBM, Liner, LCS, Cap, Dust, Run-on/off, PCM	\$56.82	\$224,717
1010000110000111a	1128a	UBM, Liner, LCS, Cap, Dust, Run-on/off, PCM (cap and PCM costs accrue after closure)	\$55.33	\$222,782
0010000110000110	1129	Liner, LCS, Cap, Dust, Run-on/off	\$56.70	\$159,993
0010000100000110	1130	Liner, LCS, Dust, Run-on/off	\$55.04	\$157,673
1001000010000001	1131	UBM, Clay liner, Cap, PCM	\$38.46	\$165,305
0010000000010000	1132	Liner, Soil Cap	\$45.60	\$116,621
0010000000010000a	1132a	Liner, Soil Cap (cap cost accrues after closure)	\$44.50	\$115,069
0000000010000001	1134	Cap, PCM	\$7.33	\$86,361
0010000101000100	1135	Liner, LCS, Clay Cap, Dust	\$57.70	\$151,645
0010000101000110	1136	Liner, LCS, Clay Cap, Dust, Run-on/off	\$57.78	\$161,144
1010000001000000	1137	UBM, Liner, Clay Cap	\$47.27	\$179,456
0010000101000010	1138	Liner, LCS, Clay Cap, Run-on/off	\$57.51	\$160,915
1010000101000110	1140	UBM, Liner, LCS, Clay Cap, Dust, Run-on/off	\$57.90	\$222,416
1010000101000010	1142	UBM, Liner, LCS, Clay Cap, Run-on/off	\$57.63	\$222,188
1010000101000011	1143	UBM, Liner, LCS, Clay Cap, Run-on/off, PCM	\$57.64	\$225,640
1010000101001011	1144	UBM, Liner, LCS, Clay Cap, FA, Run-on/off, PCM	\$59.73	\$235,151
1010000110001011	1145	UBM, Liner, LCS, Cap, FA, Run-on/off, PCM	\$58.65	\$233,999
0010000100010010	1146	Liner, LCS, Soil Cap, Run-on/off	\$55.95	\$159,352
1010000100010010	1147	UBM, Liner, LCS, Soil Cap, Run-on/off	\$56.07	\$220,625

Exhibit D-2 Pile Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Pile Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
1010000100010011	1148	UBM, Liner, LCS, Soil cap, Run-on/off, PCM	\$56.08	\$224,077
1010000100011011	1149	UBM, Liner, LCS, Soil Cap, FA, Run-on/off, PCM	\$58.19	\$233,588
1010000101000000	1150	UBM, Liner, LCS, Clay Cap	\$57.54	\$212,689
0010000100010110	1151	Liner, LCS, Soil Cap, Dust, Run-on/off	\$56.23	\$159,582
1010000100010110	1152	UBM, Liner, LCS, Soil Cap, Dust, Run-on/off	\$56.34	\$220,855
1010000100010111	1153	UBM, Liner, LCS, Soil Cap, Dust, Run-on/off, PCM	\$56.36	\$224,306
1010000100011111	1154	UBM, Liner, LCS, Soil Cap, FA, Dust, Run-on/off, PCM	\$58.45	\$233,817
0010000000000100	1155	Liner, Dust	\$44.68	\$114,942
0010000000010100	1156	Liner, Soil Cap, Dust	\$45.87	\$116,850
1010000000010100	1157	UBM, Liner, Soil Cap, Dust	\$45.99	\$178,123
0001000000000100	1158	Clay Liner, Dust	\$36.94	\$98,489
0001000000000110	1159	Clay Liner, Dust, Run-on/off	\$37.03	\$107,987
0001000001000110	1160	Clay Liner, Clay Cap, Dust, Run-on/off	\$39.77	\$111,458
1001000001000110	1161	UBM, Clay Liner, Clay Cap, Dust, Run-on/off	\$39.89	\$172,731
1001000001000111	1162	UBM, Clay Liner, Clay Cap, Dust, Run-on/off, PCM	\$39.89	\$176,183
0001000100000000	1163	Clay Liner, LCS	\$46.94	\$131,639
0001000100000100	1164	Clay Liner, LCS, Dust	\$47.21	\$131,868
0001000100000110	1165	Clay Liner, LCS, Dust, Run-on/off	\$47.29	\$141,367
0001000101000110	1166	Clay Liner, LCS, Clay Cap, Dust, Run-on/off	\$50.04	\$144,837
1001000101000110	1167	UBM, Clay Liner, LCS, Clay Cap, Dust, Run-on/off	\$50.16	\$206,110
1001000101000111	1168	UBM, Clay Liner, LCS, Clay Cap, Dust, Run-on/off, PCM	\$50.16	\$209,562
0001000100010000	1170	Clay Liner, LCS, Soil Cap	\$48.13	\$133,548
0001000100010000a	1170a	Clay Liner, LCS, Soil Cap (cap cost accrues after closure)	\$47.03	\$131,996
1010000100000100	1171	UBM, Liner, LCS, Dust	\$55.07	\$209,447
1010000100000110	1172	UBM, Liner, LCS, Dust, Run-on/off	\$55.16	\$218,946
1010000001001111	1173	UBM, Liner, Clay Cap, FA, Dust, Run-on/off, PCM	\$49.73	\$202,146
0010000110000100	1174	Liner, LCS, Cap, Dust	\$56.62	\$150,494
1010000110000100	1175	UBM, Liner, LCS, Cap, Dust	\$56.74	\$211,767
1010000110000101	1176	UBM, Liner, LCS, Cap, Dust, PCM	\$56.74	\$215,219
1010000110001010	1177	UBM, Liner, LCS, Cap, FA, Run-on/off	\$58.65	\$230,548
0000100000000000	1186	Ash Liner	\$13.21	\$96,979
0010000000100000	1191	Liner, Ash Cap	\$45.83	\$118,150
0000000000010100	1192	Soil Cap, Dust	\$7.12	\$82,727
1000000000010100	1193	UBM, Soil Cap, Dust	\$7.24	\$144,000
1010000101000100	1194	UBM, Liner, LCS, Clay Cap, Dust	\$57.82	\$212,918
1010000110001110	1195	UBM, Liner, LCS, Cap, FA, Dust, Run-on/off	\$58.91	\$230,777
0000000001000011	1196	Clay Cap, Run-on/off, PCM	\$8.49	\$97,011

Exhibit D-2 Pile Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Pile Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
1010000100011010	1197	UBM, Liner, LCS, Soil Cap, FA, Run-on/off	\$58.17	\$230,136
1010000001000011	1198	UBM, Liner, Clay Cap, Run-on/off, PCM	\$47.37	\$192,406
1010000010001001	1200	UBM, Liner, Cap, FA, PCM	\$48.30	\$191,268
0010000101000111	1202	Liner, LCS, Clay Cap, Dust, Run-on/off, PCM	\$57.78	\$164,596
0010000101000011	1203	Liner, LCS, Clay Cap, Run-on/off, PCM	\$57.52	\$164,367
0010000001000011	1204	Liner, Clay Cap, Run-on/off, PCM	\$47.25	\$131,134
0010000110000111	1205	Liner, LCS, Cap, Dust, Run-on/off, PCM	\$56.70	\$163,445
1010000100011110	1206	UBM, Liner, LCS, Soil Cap, FA, Dust, Run-on/off	\$58.45	\$230,365
0001000000000010	1207	Clay Liner, Run-on/off	\$36.75	\$107,759
0001000001000010	1208	Clay Liner, Clay Cap, Run-on/off	\$39.50	\$111,229
1001000001000010	1209	UBM, Clay liner, Clay Cap, Run-on/off	\$39.62	\$172,502
1001000001000011	1210	UBM, Clay liner, Clay Cap, Run-on/off, PCM	\$39.63	\$175,954
0000000100000000	3001	LCS,	\$15.93	\$113,823
0000000100011001	3002	LCS, Soil Cap, FA, PCM,	\$19.23	\$128,695
0000000110001001	3003	LCS, Synth Cap, FA, PCM,	\$19.71	\$129,106
0001000000010000	3004	Clay Liner, Soil Cap,	\$37.86	\$100,168
0001000000010000a	3004a	Clay Liner, Soil Cap (cap cost accrues after closure)	\$36.76	\$98,617
0001000000011001	3005	Clay Liner, Soil Cap, FA, PCM,	\$39.96	\$113,132
0001000010001001	3006	Clay Liner, Synth Cap, FA, PCM,	\$40.44	\$113,543
0001000100011001	3007	Clay Liner, LCS, Soil Cap, FA, PCM,	\$50.23	\$146,365
0001000101000000	3008	Clay Liner, LCS, Clay Cap,	\$49.68	\$134,964
0001000101000011	3009	Clay Liner, LCS, Clay Cap, Run on/off, PCM,	\$49.78	\$147,915
0001000110001001	3010	Clay Liner, LCS, Synth Cap, FA, PCM,	\$50.71	\$146,776
0010000010001001	3011	Synth Liner, Synth Cap, FA, PCM,	\$48.19	\$129,996
0010000100011001	3012	Synth Liner, LCS, Soil Cap, FA, PCM,	\$57.98	\$162,817
0010000110001001	3013	Synth Liner, LCS, Synth Cap, FA, PCM,	\$58.45	\$163,229
1000000000011010	3014	UBM, Soil Cap, FA, Run on/off,	\$9.16	\$162,780
1000000000011011	3015	UBM, Soil Cap, FA, Run on/off, PCM,	\$9.17	\$166,233
1000000000011111	3016	UBM, Soil Cap, FA, Dust, Run on/off, PCM,	\$9.44	\$166,461
1000000001001011	3017	UBM, Clay Cap, FA, Run on/off, PCM,	\$10.72	\$167,795
1000000001001110	3018	UBM, Clay Cap, FA, Dust, Run on/off,	\$10.99	\$164,572
1000000010000011	3019	UBM, Synth Cap, Run on/off, PCM,	\$7.54	\$157,133
1000000010000111	3020	UBM, Synth Cap, Dust, Run on/off, PCM,	\$7.82	\$157,362
1000000010001011	3021	UBM, Synth Cap, FA, Run on/off, PCM,	\$9.65	\$166,644
1000000010001101	3022	UBM, Synth Cap, FA, Dust, PCM,	\$9.83	\$157,375
1000000010001111	3023	UBM, Synth Cap, FA, Dust, Run on/off, PCM,	\$9.92	\$166,873
1000000100000000	3024	UBM, LCS,	\$16.05	\$175,096

Exhibit D-2 Pile Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Pile Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
1000000100001100	3025	UBM, LCS, FA, Dust,	\$18.43	\$184,836
1000000100010000	3026	UBM, LCS, Soil Cap,	\$17.24	\$177,004
1000000100010000a	3026a	UBM, LCS, Soil Cap (cap cost accrues after closure)	\$16.14	\$175,598
1000000100011010	3027	UBM, LCS, Soil Cap, FA, Run on/off,	\$19.43	\$196,013
1000000100011011	3028	UBM, LCS, Soil Cap, FA, Run on/off, PCM,	\$19.44	\$199,466
1000000100011111	3029	UBM, LCS, Soil Cap, FA, Dust, Run on/off, PCM,	\$19.71	\$199,694
1000000100100000	3030	UBM, LCS, Ash Cap,	\$17.47	\$178,533
1000000101001110	3031	UBM, LCS, Clay Cap, FA, Dust, Run on/off,	\$21.26	\$197,805
1000000101001111	3032	UBM, LCS, Clay Cap, FA, Dust, Run on/off, PCM,	\$21.27	\$201,257
1000000110000011	3033	UBM, LCS, Synth Cap, Run on/off, PCM,	\$17.81	\$190,366
1000000110000111	3034	UBM, LCS, Synth Cap, Dust, Run on/off, PCM,	\$18.09	\$190,595
1000000110001001	3035	UBM, LCS, Synth Cap, FA, PCM,	\$19.83	\$190,379
1000000110001011	3036	UBM, LCS, Synth Cap, FA, Run on/off, PCM,	\$19.92	\$199,877
1000000110001101	3037	UBM, LCS, Synth Cap, FA, Dust, PCM,	\$20.10	\$190,608
1000000110001111	3038	UBM, LCS, Synth Cap, FA, Dust, Run on/off, PCM,	\$20.19	\$200,106
1001000000011011	3039	UBM, Clay Liner, Soil Cap, FA, Run on/off, PCM,	\$40.17	\$183,903
1001000000011111	3040	UBM, Clay Liner, Soil Cap, FA, Dust, Run on/off, PCM,	\$40.44	\$184,131
1001000001001110	3041	UBM, Clay Liner, Clay Cap, FA, Dust, Run on/off,	\$41.99	\$182,242
1001000010001011	3042	UBM, Clay Liner, Synth Cap, FA, Run on/off, PCM,	\$40.65	\$184,314
1001000010001101	3043	UBM, Clay Liner, Synth Cap, FA, Dust, PCM,	\$40.83	\$175,045
1001000010001111	3044	UBM, Clay Liner, Synth Cap, FA, Dust, Run on/off, PCM,	\$40.92	\$184,543
1001000100000000	3045	UBM, Clay Liner, LCS,	\$47.06	\$192,766
1001000100011010	3046	UBM, Clay Liner, LCS, Soil Cap, FA, Run on/off,	\$50.43	\$213,684
1001000100011011	3047	UBM, Clay Liner, LCS, Soil Cap, FA, Run on/off, PCM,	\$50.44	\$217,136
1001000100011111	3048	UBM, Clay Liner, LCS, Soil Cap, FA, Dust, Run on/off, PCM,	\$50.71	\$217,364
1001000100100000	3049	UBM, Clay Liner, LCS, Ash Cap,	\$48.47	\$196,203
1001000101000000	3050	UBM, Clay Liner, LCS, Clay Cap,	\$49.80	\$196,237
1001000101000011	3051	UBM, Clay Liner, LCS, Clay Cap, Run on/off, PCM,	\$49.90	\$209,187
1001000110000000	3052	UBM, Clay Liner, LCS, Synth Cap,	\$48.72	\$195,086
1001000110000111	3053	UBM, Clay Liner, LCS, Synth Cap, Dust, Run on/off, PCM,	\$49.09	\$208,265
1001000110001001	3054	UBM, Clay Liner, LCS, Synth Cap, FA, PCM,	\$50.83	\$208,049
1001000110001011	3055	UBM, Clay Liner, LCS, Synth Cap, FA, Run on/off, PCM,	\$50.92	\$217,547
1001000110001111	3056	UBM, Clay Liner, LCS, Synth Cap, FA, Dust, Run on/off, PCM,	\$51.19	\$217,776
1010000000011011	3057	UBM, Synth Liner, Soil Cap, FA, Run on/off, PCM,	\$47.91	\$200,355
1010000000011111	3058	UBM, Synth Liner, Soil Cap, FA, Dust, Run on/off, PCM,	\$48.19	\$200,584

Exhibit D-2 Pile Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Pile Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
1010000001001110	3059	UBM, Synth Liner, Clay Cap, FA, Dust, Run on/off,	\$49.74	\$198,694
10100000010001011	3060	UBM, Synth Liner, Synth Cap, FA, Run on/off, PCM,	\$48.39	\$200,767
10100000010001101	3061	UBM, Synth Liner, Synth Cap, FA, Dust, PCM,	\$48.58	\$191,497
10100000010001111	3062	UBM, Synth Liner, Synth Cap, FA, Dust, Run on/off, PCM,	\$48.66	\$200,995
10100000100010000	3063	UBM, Synth Liner, LCS, Soil Cap,	\$55.99	\$211,126
10100000100010000a	3063a	UBM, Synth Liner, LCS, Soil Cap (cap cost accrues after closure)	\$54.89	\$209,721
10100000100100000	3064	UBM, Synth Liner, LCS, Ash Cap,	\$56.21	\$212,655
10010000110000011	3065	UBM, Clay Liner, LCS, Synth Cap, Run on/off, PCM,	\$48.82	\$208,036
10000000101000011	3066	UBM, LCS, Clay Cap, Run on/off, PCM,	\$18.89	\$191,517
10000000101000000	3067	UBM, LCS, Clay Cap,	\$18.80	\$178,567
10010000000100000	3068	UBM, Clay Liner, Ash Cap,	\$38.20	\$162,970
10010000000011100	3069	UBM, Clay Liner, Soil Cap, FA, Dust,	\$40.35	\$171,181
00000000101000011	3070	LCS, Clay Cap, Run on/off, PCM,	\$18.77	\$130,244
10000000110000000	3071	UBM, LCS, Synth Cap,	\$17.72	\$177,416
00000000101000000	3072	LCS, Clay Cap,	\$18.68	\$117,294
00000000101000000a	3072a	LCS, Clay Cap (cap cost accrues after closure)	\$16.13	\$114,206
10100000100001111	3073	UBM, Synth Liner, LCS, FA, Dust, Run on/off, PCM,	\$57.27	\$231,909
10000000000001111	3074	UBM, FA, Dust, Run on/off, PCM,	\$8.25	\$164,553
10000000100001111	3075	UBM, LCS, FA, Dust, Run on/off, PCM,	\$18.52	\$197,786
10010000100001111	3076	UBM, Clay Liner, LCS, FA, Dust, Run on/off, PCM,	\$49.52	\$215,456
10010000100001110	3077	UBM, Clay Liner, LCS, FA, Dust, Run on/off,	\$49.52	\$212,004
10100000100001110	3078	UBM, Synth Liner, LCS, FA, Dust, Run on/off,	\$57.26	\$228,457
10000000100001110	3079	UBM, LCS, FA, Dust, Run on/off,	\$18.51	\$194,334
10010000000001111	3080	UBM, Clay Liner, FA, Dust, Run on/off, PCM,	\$39.26	\$182,223
00000000000000011	3081	Run on/off, PCM,	\$5.76	\$93,541
00000000100000011	3082	LCS, Run on/off, PCM,	\$16.03	\$126,774
00100000100000011	3083	Synth Liner, LCS, Run on/off, PCM,	\$54.77	\$160,896
00010000100000011	3084	Clay Liner, LCS, Run on/off, PCM,	\$47.03	\$144,444
10100000100001011	3085	UBM, Synth Liner, LCS, FA, Run on/off, PCM,	\$57.00	\$231,680
10000000100001000	3086	UBM, LCS, FA,	\$18.16	\$184,607
10000000000001000	3087	UBM, FA,	\$7.89	\$151,374
10100000000001000	3088	UBM, Synth Liner, FA,	\$46.63	\$185,497
10010000000001000	3089	UBM, Clay Liner, FA,	\$38.89	\$169,044
10100000100001000	3090	UBM, Synth Liner, LCS, FA,	\$56.90	\$218,730
10010000100001000	3091	UBM, Clay Liner, LCS, FA,	\$49.16	\$202,277
00000000110000011	3092	LCS, Synth Cap, Run on/off, PCM,	\$17.69	\$129,093

Exhibit D-2 Pile Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Pile Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
0001000110000011	3093	Clay Liner, LCS, Synth Cap, Run on/off, PCM,	\$48.70	\$146,763
0001000110000011a	3093a	Clay Liner, LCS, Synth Cap, Run on/off, PCM (cap and PCM costs accrue after closure)	\$47.20	\$144,974
0010000110000011	3094	Synth Liner, LCS, Synth Cap, Run on/off, PCM,	\$56.44	\$163,216
1000000101001101	3095	UBM, LCS, Clay Cap, FA, Dust, PCM,	\$21.18	\$191,759
1010000101001101	3096	UBM, Synth Liner, LCS, Clay Cap, FA, Dust, PCM,	\$59.92	\$225,881
1001000101001101	3097	UBM, Clay Liner, LCS, Clay Cap, FA, Dust, PCM,	\$52.18	\$209,429
1000000001001101	3098	UBM, Clay Cap, FA, Dust, PCM,	\$10.91	\$158,526
1010000001001101	3099	UBM, Synth Liner, Clay Cap, FA, Dust, PCM,	\$49.66	\$192,648
0010000101001111	3100	Synth Liner, LCS, Clay Cap, FA, Dust, Run on/off, PCM,	\$59.89	\$174,107
1000000000001110	3101	UBM, FA, Dust, Run on/off,	\$8.25	\$161,101
1010000000001111	3102	UBM, Synth Liner, FA, Dust, Run on/off, PCM,	\$47.00	\$198,676
1001000000001111	3103	UBM, Clay Liner, FA, Dust, Run on/off, PCM,	\$39.26	\$182,223
0000000100001110	3104	LCS, FA, Dust, Run on/off,	\$18.39	\$133,062
0010000100001110	3105	Synth Liner, LCS, FA, Dust, Run on/off,	\$57.14	\$167,184
0001000100001110	3106	Clay Liner, LCS, FA, Dust, Run on/off,	\$49.40	\$150,732
0000000000001110	3107	FA, Dust, Run on/off,	\$8.13	\$99,829
0010000000001110	3108	Synth Liner, FA, Dust, Run on/off,	\$46.87	\$133,951
0001000000001110	3109	Clay Liner, FA, Dust, Run on/off,	\$39.13	\$117,499
1010000000001110	3110	UBM, Synth Liner, FA, Dust, Run on/off,	\$46.99	\$195,224
1001000000001110	3111	UBM, Clay Liner, FA, Dust, Run on/off,	\$39.25	\$178,771
1000000000001001	3112	UBM, FA, PCM,	\$7.89	\$154,826
1010000000001001	3113	UBM, Synth Liner, FA, PCM,	\$46.64	\$188,949
1001000000001001	3114	UBM, Clay Liner, FA, PCM,	\$38.90	\$172,497
1000000100001001	3115	UBM, LCS, FA, PCM,	\$18.16	\$188,059
1010000100001001	3116	UBM, Synth Liner, LCS, FA, PCM,	\$56.91	\$222,182
1001000100001001	3117	UBM, Clay Liner, LCS, FA, PCM,	\$49.17	\$205,730
0000000100000001	3118	LCS, PCM,	\$15.94	\$117,275
0010000100000001	3119	Synth Liner, LCS, PCM,	\$54.69	\$151,398
0001000100000001	3120	Clay Liner, LCS, PCM,	\$46.94	\$134,946
1000000100001101	3121	UBM, LCS, FA, Dust, PCM,	\$18.43	\$188,288
1010000100001101	3122	UBM, Synth Liner, LCS, FA, Dust, PCM,	\$57.18	\$222,410
1001000100001101	3123	UBM, Clay Liner, LCS, FA, Dust, PCM,	\$49.44	\$205,958
1000000000001011	3124	UBM, FA, Run on/off, PCM,	\$7.98	\$164,325
1010000000001011	3125	UBM, Synth Liner, FA, Run on/off, PCM,	\$46.73	\$198,447
1001000000001011	3126	UBM, Clay Liner, FA, Run on/off, PCM,	\$38.98	\$181,995
1000000100001011	3127	UBM, LCS, FA, Run on/off, PCM,	\$18.25	\$197,558

Exhibit D-2 Pile Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Pile Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
1010000100001011	3128	UBM, Synth Liner, LCS, FA, Run on/off, PCM,	\$57.00	\$231,680
1001000100001011	3129	UBM, Clay Liner, LCS, FA, Run on/off, PCM,	\$49.25	\$215,228
1010000000001101	3130	UBM, Synth Liner, FA, Dust, PCM,	\$46.91	\$189,177
1001000000001101	3131	UBM, Clay Liner, Dust, Run on/off,	\$37.15	\$169,260
1001000000001101	3132	UBM, Clay Liner, FA, Dust, PCM,	\$39.17	\$172,725
1000000001001000	3133	UBM, Clay Cap, FA,	\$10.63	\$154,845
1010000001001000	3134	UBM, Synth Liner, Clay Cap, FA,	\$49.38	\$188,967
1001000001001000	3135	UBM, Clay Liner, Clay Cap, FA,	\$41.63	\$172,515
0001000110000000	3136	Clay Liner, LCS, Synth Cap,	\$48.60	\$133,813
0000000100010000	3137	LCS, Soil Cap,	\$17.12	\$115,731
0000000100010000a	3137a	LCS, Soil Cap (cap cost accrues after closure)	\$16.02	\$114,180
0000000000011110	3138	Soil Cap, FA, Dust, Run on/off,	\$9.31	\$101,737
0010000000011110	3139	Synth Liner, Soil Cap, FA, Dust, Run on/off,	\$48.06	\$135,859
0001000000011110	3140	Clay Liner, Soil Cap, FA, Dust, Run on/off,	\$40.32	\$119,407
0000000100011110	3141	LCS, Soil Cap, FA, Dust, Run on/off,	\$19.58	\$134,970
0010000100011110	3142	Synth Liner, LCS, Soil Cap, FA, Dust, Run on/off,	\$58.33	\$169,092
0001000100011110	3143	Clay Liner, LCS, Soil Cap, FA, Dust, Run on/off,	\$50.59	\$152,640
1000000000011001	3144	UBM, Soil Cap, FA, PCM,	\$9.08	\$156,734
1010000000011001	3145	UBM, Synth Liner, Soil Cap, FA, PCM,	\$47.83	\$190,857
1001000000011001	3146	UBM, Clay Liner, Soil Cap, FA, PCM,	\$40.08	\$174,404
1000000100011001	3147	UBM, LCS, Soil Cap, FA, PCM,	\$19.35	\$189,967
1010000100011001	3148	UBM, Synth Liner, LCS, Soil Cap, FA, PCM,	\$58.10	\$224,090
1001000100011001	3149	UBM, Clay Liner, LCS, Soil Cap, FA, PCM,	\$50.35	\$207,637
0010000100010000	3150	Synth Liner, LCS, Soil Cap,	\$55.87	\$149,854
0010000110001000	3151	Synth Liner, LCS, Synth Cap, FA,	\$58.45	\$159,777
0010000110001011	3152	Synth Liner, LCS, Synth Cap, FA, Run on/off, PCM,	\$58.54	\$172,727
0010000110001111	3153	Synth Liner, LCS, Synth Cap, FA, Dust, Run on/off, PCM,	\$58.81	\$172,956
1010000101001000	3154	UBM, Synth Liner, LCS, Clay Cap, FA,	\$59.65	\$222,200
1010000110001000	3155	UBM, Synth Liner, LCS, Synth Cap, FA,	\$58.57	\$221,049
1000010110001111	20001	UBM, Yes Liner, LCS, Synth Cap, FA, Dust, Run on/off, PCM,	\$55.34	\$226,612
1000010110001101	20002	UBM, Yes Liner, LCS, Synth Cap, FA, Dust, PCM,	\$55.25	\$217,113
1000010110001011	20003	UBM, Yes Liner, LCS, Synth Cap, FA, Run on/off, PCM,	\$55.07	\$226,382
1000010110001001	20004	UBM, Yes Liner, LCS, Synth Cap, FA, PCM,	\$54.99	\$216,884
1000010110000111	20005	UBM, Yes Liner, LCS, Synth Cap, Dust, Run on/off, PCM,	\$53.24	\$217,100
1000010110000011	20006	UBM, Yes Liner, LCS, Synth Cap, Run on/off, PCM,	\$52.98	\$216,872
1000010110000000	20007	UBM, Yes Liner, LCS, Synth Cap,	\$52.88	\$204,000

Exhibit D-2 Pile Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Pile Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
1000010101001111	20008	UBM, Yes Liner, LCS, Clay Cap, FA, Dust, Run on/off, PCM,	\$56.42	\$227,763
1000010101001110	20009	UBM, Yes Liner, LCS, Clay Cap, FA, Dust, Run on/off,	\$56.41	\$224,378
1000010101000011	20010	UBM, Yes Liner, LCS, Clay Cap, Run on/off, PCM,	\$54.05	\$218,023
1000010101000000	20011	UBM, Yes Liner, LCS, Clay Cap,	\$53.96	\$205,072
1000010100100000	20012	UBM, Yes Liner, LCS, Ash Cap,	\$52.63	\$205,038
1000010100011111	20013	UBM, Yes Liner, LCS, Soil Cap, FA, Dust, Run on/off, PCM,	\$54.87	\$226,200
1000010100011011	20014	UBM, Yes Liner, LCS, Soil Cap, FA, Run on/off, PCM,	\$54.60	\$225,971
1000010100011010	20015	UBM, Yes Liner, LCS, Soil Cap, FA, Run on/off,	\$54.59	\$222,519
1000010100010000	20016	UBM, Yes Liner, LCS, Soil Cap,	\$52.40	\$203,577
1000010100010000a	20016a	UBM, Yes Liner, LCS, Soil Cap (cap cost accrues after closure)	\$51.31	\$202,036
1000010100001111	20017	UBM, Yes Liner, LCS, FA, Dust, Run on/off, PCM,	\$53.68	\$224,292
1000010100001110	20018	UBM, Yes Liner, LCS, FA, Dust, Run on/off,	\$53.68	\$220,840
1000010100000000	20019	UBM, Yes Liner, LCS,	\$51.21	\$201,680
1000010010001111	20020	UBM, Yes Liner, Synth Cap, FA, Dust, Run on/off, PCM,	\$45.08	\$193,378
1000010010001101	20021	UBM, Yes Liner, Synth Cap, FA, Dust, PCM,	\$44.99	\$183,880
1000010010001011	20022	UBM, Yes Liner, Synth Cap, FA, Run on/off, PCM,	\$44.81	\$193,150
1000010010001001	20023	UBM, Yes Liner, Synth Cap, FA, PCM,	\$44.71	\$183,651
1000010001001111	20024	UBM, Yes Liner, Clay Cap, FA, Dust, Run on/off, PCM,	\$46.15	\$194,530
1000010001001110	20025	UBM, Yes Liner, Clay Cap, FA, Dust, Run on/off,	\$46.15	\$191,077
1000010001000011	20026	UBM, Yes Liner, Clay Cap, Run on/off, PCM,	\$43.79	\$184,790
1000010001000000	20027	UBM, Yes Liner, Clay Cap,	\$43.69	\$171,839
1000010000100000	20028	UBM, Yes Liner, Ash Cap,	\$42.36	\$171,806
1000010000011111	20029	UBM, Yes Liner, Soil Cap, FA, Dust, Run on/off, PCM,	\$44.60	\$192,967
1000010000011100	20030	UBM, Yes Liner, Soil Cap, FA, Dust,	\$44.50	\$180,017
1000010000011011	20031	UBM, Yes Liner, Soil Cap, FA, Run on/off, PCM,	\$44.33	\$192,738
1000010000010000	20032	UBM, Yes Liner, Soil Cap,	\$42.13	\$170,277
1000010000000000	20033	UBM, Yes Liner,	\$40.95	\$168,369
0000010110001001	20034	Yes Liner, LCS, Synth Cap, FA, PCM,	\$54.87	\$155,612
0000010101000011	20035	Yes Liner, LCS, Clay Cap, Run on/off, PCM,	\$53.94	\$156,750
0000010101000000	20036	Yes Liner, LCS, Clay Cap,	\$53.84	\$143,800
0000010101000000a	20036a	Yes Liner, LCS, Clay Cap (cap cost accrues after closure)	\$51.29	\$140,779
0000010100011001	20037	Yes Liner, LCS, Soil Cap, FA, PCM,	\$54.39	\$155,200
0000010100000011	20038	Yes Liner, LCS, Run on/off, PCM,	\$51.19	\$153,279
0000010100000000	20039	Yes Liner, LCS,	\$51.10	\$140,397
0000010010001001	20040	Yes Liner, Synth Cap, FA, PCM,	\$44.60	\$122,379

Exhibit D-2 Pile Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Pile Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
0000010001000000	20041	Yes Liner, Clay Cap,	\$43.57	\$110,567
0000010000010000	20042	Yes Liner, Soil Cap,	\$42.01	\$109,004
0000010000000100	20043	Yes Liner, Dust,	\$41.10	\$107,325
0000010000000000	20044	Yes Liner,	\$40.83	\$107,096
1000010000001000	20045	UBM, Yes Liner, FA,	\$43.05	\$177,880
1000010100001000	20046	UBM, Yes Liner, LCS, FA,	\$53.32	\$211,113
0000010110000011	20047	Yes Liner, LCS, Synth Cap, Run on/off, PCM,	\$52.86	\$155,599
0000010110000011a	20047a	Yes Liner, LCS, Synth Cap, Run on/off, PCM (cap and PCM costs accrue after closure)	\$51.36	\$153,663
1000010101001101	20048	UBM, Yes Liner, LCS, Clay Cap, FA, Dust, PCM,	\$56.34	\$218,264
1000010001001101	20049	UBM, Yes Liner, Clay Cap, FA, Dust, PCM,	\$46.07	\$185,031
1000010000001111	20050	UBM, Yes Liner, FA, Dust, Run on/off, PCM,	\$43.41	\$191,059
0000010100001110	20051	Yes Liner, LCS, FA, Dust, Run on/off,	\$53.56	\$159,567
1000010000001110	20052	UBM, Yes Liner, FA, Dust, Run on/off,	\$43.41	\$187,607
1000010100001001	20053	UBM, Yes Liner, LCS, FA, PCM,	\$53.32	\$214,565
0000010100000001	20054	Yes Liner, LCS, PCM,	\$51.10	\$143,781
0000010100000001a	20054a	Yes Liner, LCS, PCM (PCM cost accrues after closure)	\$51.10	\$143,849
1000010100001101	20055	UBM, Yes Liner, LCS, FA, Dust, PCM,	\$53.60	\$214,794
1000010000001011	20056	UBM, Yes Liner, FA, Run on/off, PCM,	\$43.14	\$190,830
1000010100001011	20057	UBM, Yes Liner, LCS, FA, Run on/off, PCM,	\$53.41	\$224,063
1000010000001101	20058	UBM, Yes Liner, FA, Dust, PCM,	\$43.33	\$181,561
0000010100011110	20059	Yes Liner, LCS, Soil Cap, FA, Dust, Run on/off,	\$54.74	\$161,475
1000010100011001	20060	UBM, Yes Liner, LCS, Soil Cap, FA, PCM,	\$54.51	\$216,473
1000001110001111	21001	UBM, Unknown Liner, LCS, Synth Cap, FA, Dust, Run on/off, PCM,	\$28.51	\$206,384
1000001110001101	21002	UBM, Unknown Liner, LCS, Synth Cap, FA, Dust, PCM,	\$28.43	\$196,885
1000001110001011	21003	UBM, Unknown Liner, LCS, Synth Cap, FA, Run on/off, PCM,	\$28.24	\$206,155
1000001110001001	21004	UBM, Unknown Liner, LCS, Synth Cap, FA, PCM,	\$28.15	\$196,657
1000001110000111	21005	UBM, Unknown Liner, LCS, Synth Cap, Dust, Run on/off, PCM,	\$26.41	\$196,872
1000001110000011	21006	UBM, Unknown Liner, LCS, Synth Cap, Run on/off, PCM,	\$26.14	\$196,644
1000001110000000	21007	UBM, Unknown Liner, LCS, Synth Cap,	\$26.05	\$183,712
1000001101001111	21008	UBM, Unknown Liner, LCS, Clay Cap, FA, Dust, Run on/off, PCM,	\$29.59	\$207,535
1000001101001110	21009	UBM, Unknown Liner, LCS, Clay Cap, FA, Dust, Run on/off,	\$29.58	\$204,099
1000001101000011	21010	UBM, Unknown Liner, LCS, Clay Cap, Run on/off, PCM,	\$27.22	\$197,795
1000001101000000	21011	UBM, Unknown Liner, LCS, Clay Cap,	\$27.13	\$184,844

Exhibit D-2 Pile Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Pile Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
1000001100100000	21012	UBM, Unknown Liner, LCS, Ash Cap,	\$25.80	\$184,810
1000001100011111	21013	UBM, Unknown Liner, LCS, Soil Cap, FA, Dust, Run on/off, PCM,	\$28.03	\$205,972
1000001100011011	21014	UBM, Unknown Liner, LCS, Soil Cap, FA, Run on/off, PCM,	\$27.76	\$205,743
1000001100011010	21015	UBM, Unknown Liner, LCS, Soil Cap, FA, Run on/off,	\$27.76	\$202,291
1000001100010000	21016	UBM, Unknown Liner, LCS, Soil Cap,	\$25.57	\$183,298
1000001100001111	21017	UBM, Unknown Liner, LCS, FA, Dust, Run on/off, PCM,	\$26.85	\$204,064
1000001100001110	21018	UBM, Unknown Liner, LCS, FA, Dust, Run on/off,	\$26.84	\$200,612
1000001100000000	21019	UBM, Unknown Liner, LCS,	\$24.38	\$181,392
1000001010001111	21020	UBM, Unknown Liner, Synth Cap, FA, Dust, Run on/off, PCM,	\$18.25	\$173,151
1000001010001101	21021	UBM, Unknown Liner, Synth Cap, FA, Dust, PCM,	\$18.16	\$163,652
1000001010001011	21022	UBM, Unknown Liner, Synth Cap, FA, Run on/off, PCM,	\$17.97	\$172,922
1000001010001001	21023	UBM, Unknown Liner, Synth Cap, FA, PCM,	\$17.88	\$163,423
1000001001001111	21024	UBM, Unknown Liner, Clay Cap, FA, Dust, Run on/off, PCM,	\$19.32	\$174,302
1000001001001110	21025	UBM, Unknown Liner, Clay Cap, FA, Dust, Run on/off,	\$19.32	\$170,849
1000001001000011	21026	UBM, Unknown Liner, Clay Cap, Run on/off, PCM,	\$16.94	\$164,562
1000001001000000	21027	UBM, Unknown Liner, Clay Cap,	\$16.85	\$151,611
1000001000100000	21028	UBM, Unknown Liner, Ash Cap,	\$15.53	\$151,578
1000001000011111	21029	UBM, Unknown Liner, Soil Cap, FA, Dust, Run on/off, PCM,	\$17.77	\$172,739
1000001000011100	21030	UBM, Unknown Liner, Soil Cap, FA, Dust,	\$17.66	\$159,789
1000001000011011	21031	UBM, Unknown Liner, Soil Cap, FA, Run on/off, PCM,	\$17.49	\$172,510
1000001000010000	21032	UBM, Unknown Liner, Soil Cap,	\$15.30	\$150,049
1000001000000000	21033	UBM, Unknown Liner,	\$14.11	\$148,141
0000001110001001	21034	Unknown Liner, LCS, Synth Cap, FA, PCM,	\$28.04	\$135,384
0000001101000011	21035	Unknown Liner, LCS, Clay Cap, Run on/off, PCM,	\$27.10	\$136,522
0000001101000000	21036	Unknown Liner, LCS, Clay Cap,	\$27.01	\$123,572
0000001100011001	21037	Unknown Liner, LCS, Soil Cap, FA, PCM,	\$27.56	\$134,972
0000001100000011	21038	Unknown Liner, LCS, Run on/off, PCM,	\$24.36	\$133,051
0000001100000000	21039	Unknown Liner, LCS,	\$24.26	\$120,117
0000001010001001	21040	Unknown Liner, Synth Cap, FA, PCM,	\$17.76	\$102,150
0000001001000000	21041	Unknown Liner, Clay Cap,	\$16.73	\$90,339
0000001000010000	21042	Unknown Liner, Soil Cap,	\$15.18	\$88,776
0000001000000100	21043	Unknown Liner, Dust,	\$14.26	\$87,097
0000001000000000	21044	Unknown Liner,	\$13.99	\$86,868
1000001000001000	21045	UBM, Unknown Liner, FA,	\$16.21	\$157,652

Exhibit D-2 Pile Landfill Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (DRY tons/yr) + Constant				
Controls Code	Cost Model Pile Landfill Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
1000001000001111	21046	UBM, Unknown Liner, FA, Dust, Run on/off, PCM,	\$16.58	\$170,831
0000001100001110	21047	Unknown Liner, LCS, FA, Dust, Run on/off,	\$26.72	\$139,339
0000001000001110	21048	Unknown Liner, FA, Dust, Run on/off,	\$16.45	\$106,106
1000001100001000	21049	UBM, Unknown Liner, LCS, FA,	\$26.48	\$190,885
1000001000001001	21050	UBM, Unknown Liner, FA, PCM,	\$16.22	\$161,104
1000001000001011	21051	UBM, Unknown Liner, FA, Run on/off, PCM,	\$16.31	\$170,602
1000001001001000	21052	UBM, Unknown Liner, Clay Cap, FA,	\$18.96	\$161,123
0000001000011110	21053	Unknown Liner, Soil Cap, FA, Dust, Run on/off,	\$17.64	\$108,014
1000001000011001	21054	UBM, Unknown Liner, Soil Cap, FA, PCM,	\$17.41	\$163,012

Exhibit D-3 Surface Impoundment Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (WET tons/yr) + Constant				
Controls Code	Cost Model Impoundment Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
00000000000000	1	No Controls	\$55.58	\$64,394
10000000000000	2	UBM	\$55.75	\$142,257
01000000000000	3	150M Mon	\$55.75	\$165,976
01000000100011	4	150M Mon, Cap, FA, PCM	\$62.31	\$187,089
10100001000000	5	UBM, Liner, LCS	\$139.42	\$378,904
00100001000000	6	Liner, LCS	\$139.26	\$301,042
10010000100011	7	UBM, Clay Liner, Cap, FA, PCM	\$117.31	\$297,018
10100001100011	8	UBM, Liner, LCS, Cap, FA, PCM	\$145.99	\$400,018
10100000000011	9	UBM, Liner, FA, PCM	\$127.91	\$320,418
00010000000100	10	Clay Liner, Soil Cap	\$112.67	\$204,538
10010001100011	11	UBM, Clay Liner, LCS, Cap, FA, PCM	\$132.45	\$368,813
10000000000010	12	UBM, FA	\$59.37	\$151,439
10100001000111	13	UBM, Liner, LCS, Soil Cap, FA, PCM	\$145.15	\$398,708
10100001000011	14	UBM, Liner, LCS, FA, PCM	\$143.06	\$392,212
10100001000001	15	UBM, Liner, LCS, PCM	\$139.43	\$383,031
10100001000001a	15a	UBM, Liner, LCS, PCM (PCM cost accrues after closure)	\$139.43	\$383,031
10000000000001	16	UBM, PCM	\$55.75	\$146,382
10000000000001a	16a	UBM, PCM (PCM cost accrues after closure)	\$55.75	\$146,383
01100000100011	17	150M Mon, Liner, Cap, FA, PCM	\$130.85	\$351,942
01100000000000	18	150M Mon, Liner	\$124.28	\$330,774
10000000000011	19	UBM, FA, PCM	\$59.38	\$155,564
00100000000000	20	Liner	\$124.12	\$229,248
00000000100011	21	Cap, FA, PCM	\$62.15	\$85,507
01100001100011	22	150M Mon, Liner, LCS, Cap, FA, PCM	\$145.99	\$423,736
01000000100001	23	150M Mon, Cap, PCM	\$58.69	\$177,908
10010000100001	24	UBM, Clay Liner, Cap, PCM	\$113.68	\$287,871
01010000100001	25	150M Mon, Clay Liner, Cap, PCM	\$113.68	\$311,556
10100001100001	26	UBM, Liner, LCS, Cap, PCM	\$142.37	\$390,837
10100001100001a	26a	UBM, Liner, LCS, Cap, PCM (cap and PCM costs accrue after closure)	\$139.72	\$383,807
01100000100001	27	150M Mon, Liner, Cap, PCM	\$127.22	\$342,761
10100000100011	28	UBM, Liner, Cap, FA, PCM	\$130.85	\$328,224
10100000000111	29	UBM, Liner, Soil Cap, FA, PCM	\$130.00	\$326,912
10000000100001	30	UBM, Cap, PCM	\$58.69	\$154,222
01010000010011	31	150M Mon, Clay Liner, Clay/Soil Cap, FA, PCM	\$121.48	\$349,555
01000000000001	32	150M Mon, PCM	\$55.75	\$170,102
10010000000101	33	UBM, Clay Liner, Soil Cap, PCM	\$112.84	\$286,527

Exhibit D-3 Surface Impoundment Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (WET tons/yr) + Constant				
Controls Code	Cost Model Impoundment Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
01010000000101	34	150M Mon, Clay Liner, Soil Cap, PCM	\$112.84	\$310,246
01010000100011	35	150M Mon, Clay Liner, Cap, FA, PCM	\$117.31	\$320,738
01100000000001	36	150M Mon, Liner, PCM	\$124.29	\$334,900
10100000000001	37	UBM, Liner, PCM	\$124.29	\$311,236
10100000100001	38	UBM, Liner, Cap, PCM	\$127.22	\$319,042
10100000100001a	38a	UBM, Liner, Cap, PCM (cap and PCM costs accrue after closure)	\$124.58	\$312,012
10000000100011	39	UBM, Cap, FA, PCM	\$62.31	\$163,370
00100001000111	40	Liner, LCS, Soil Cap, FA, PCM	\$144.99	\$320,844
10100000000000	41	UBM, Liner	\$124.28	\$307,110
10010000000000	42	UBM, Clay Liner	\$110.74	\$275,906
00010000000000	43	Clay Liner	\$110.58	\$198,042
00100001100011	44	Liner, LCS, Cap, FA, PCM	\$145.83	\$322,188
00000000000100	45	Soil Cap	\$57.68	\$70,890
10100000010011	46	UBM, Liner, Clay Cap, FA, PCM	\$132.75	\$333,453
10000000000110	47	UBM, Soil Cap, FA	\$61.46	\$157,934
10100000000010	48	UBM, Liner, FA	\$127.90	\$316,291
10000000010001	49	UBM, Clay Cap, PCM	\$60.60	\$159,418
00000000100000	50	Cap	\$58.52	\$72,200
00000000100000a	50a	Cap (cap cost accrues after closure)	\$55.87	\$65,170
00100001100000	51	Liner, LCS, Cap	\$142.20	\$308,848
10100001100000	52	UBM, Liner, LCS, Cap	\$142.36	\$386,710
10000000100000	53	UBM, Cap	\$58.68	\$150,063
01100000100000	54	150M Mon, Liner, Cap	\$127.21	\$338,580
10100000010001	55	UBM, Liner, Clay Cap, PCM	\$129.13	\$324,304
10000000010000	56	UBM, Clay Cap	\$60.59	\$155,292
00100000010000	57	Liner, Clay Cap	\$128.96	\$242,283
10100000010000	58	UBM, Liner, Clay Cap	\$129.12	\$320,145
00000000100001	59	Cap, PCM	\$58.53	\$76,326
00000000100001a	59a	Cap, PCM (cap and PCM costs accrue after closure)	\$55.88	\$69,296
00010001000000	60	Clay Liner, LCS,	\$125.73	\$269,837
00010001100000	61	Clay Liner, LCS, Cap	\$128.66	\$277,643
10010001100000	62	UBM, Clay Liner, LCS, Cap	\$128.82	\$355,506
10010001100001	63	UBM, Clay Liner, LCS, Cap, PCM	\$128.83	\$359,631
00100001100001	64	Liner, LCS, Cap, PCM	\$142.21	\$312,973
10000000000100	65	UBM, Soil Cap	\$57.84	\$148,753
10100001100010	66	UBM, Liner, LCS, Cap, FA	\$145.98	\$395,892

Exhibit D-3 Surface Impoundment Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (WET tons/yr) + Constant				
Controls Code	Cost Model Impoundment Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
00100001000100	67	Liner, LCS, Soil Cap	\$141.36	\$307,538
10100001000100	68	UBM, Liner, LCS, Soil Cap	\$141.52	\$385,400
00000000000010	69	FA	\$59.21	\$73,575
10100001000110	70	UBM, Liner, LCS, Soil Cap, FA	\$145.14	\$394,582
10100000100000	71	UBM, Liner, Cap	\$127.21	\$314,916
00000000010000	72	Clay Cap	\$60.43	\$77,429
10100001000101	73	UBM, Liner, LCS, Soil Cap, PCM	\$141.53	\$389,527
00100000100011	74	Liner, Cap, FA, PCM	\$130.69	\$250,360
10100000000110	76	UBM, Liner, Soil Cap, FA	\$129.99	\$322,787
10100001000010	78	UBM, Liner, LCS, FA	\$143.05	\$388,086
00100000000100	79	Liner, Soil Cap	\$126.21	\$235,743
00000001000000	80	LCS	\$70.73	\$136,189
10100001010001	81	UBM, Liner, LCS, Clay Cap, PCM	\$144.28	\$396,099
10100001010011	82	UBM, Liner, LCS, Clay Cap, FA, PCM	\$147.90	\$405,247
00100000100000	83	Liner, Cap	\$127.05	\$237,054
00100000100000a	83a	Liner, Cap (cap cost accrues after closure)	\$124.41	\$230,024
10100000000100	84	UBM, liner, Soil Cap	\$126.37	\$313,606
10010000000100	85	UBM, Clay liner, Soil Cap	\$112.83	\$282,402
00000001100011	1001	LCS, Synth Cap, FA, PCM,	\$77.30	\$157,302
00010000100011	1002	Clay Liner, Synth Cap, FA, PCM,	\$117.15	\$219,156
00010001100011	1003	Clay Liner, LCS, Synth Cap, FA, PCM,	\$132.30	\$290,950
10000000010011	1004	UBM, Clay Cap, FA, PCM,	\$64.22	\$168,600
10000001000000	1005	UBM, LCS,	\$70.89	\$214,052
10000001000001	1006	UBM, LCS, PCM,	\$70.90	\$218,178
10000001000111	1007	UBM, LCS, Soil Cap, FA, PCM,	\$76.62	\$233,855
10000001100001	1008	UBM, LCS, Synth Cap, PCM,	\$73.84	\$225,984
10000001100011	1009	UBM, LCS, Synth Cap, FA, PCM,	\$77.47	\$235,165
10010000000001	1010	UBM, Clay Liner, PCM,	\$110.75	\$280,032
10010000000001a	1010a	UBM, Clay Liner, PCM (PCM cost accrues after closure)	\$110.75	\$280,032
10010000000010	1011	UBM, Clay Liner, FA,	\$114.36	\$285,087
10010000010011	1012	UBM, Clay Liner, Clay Cap, FA, PCM,	\$119.22	\$302,249
10010001000000	1013	UBM, Clay Liner, LCS,	\$125.89	\$347,700
10010001000001	1014	UBM, Clay Liner, LCS, PCM,	\$125.90	\$351,826
10010001000111	1015	UBM, Clay Liner, LCS, Soil Cap, FA, PCM,	\$131.61	\$367,504
10010000000011	1016	UBM, Clay Liner, FA, PCM,	\$114.37	\$289,213
10100000010010	1017	UBM, Synth Liner, Clay Cap, FA,	\$132.75	\$329,327

Exhibit D-3 Surface Impoundment Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (WET tons/yr) + Constant				
Controls Code	Cost Model Impoundment Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
10000001010011	1018	UBM, LCS, Clay Cap, FA, PCM,	\$79.37	\$240,395
10010001010011	1019	UBM, Clay Liner, LCS, Clay Cap, FA, PCM,	\$134.37	\$374,043
00010000010000	1020	Clay Liner, Clay Cap,	\$115.42	\$211,078
00100000100001	1021	Synth Liner, Synth Cap, PCM,	\$127.06	\$241,179
00100000100001a	1021a	Synth Liner, Synth Cap, PCM, (cap and PCM costs accrue after closure)	\$124.42	\$234,150
00010000100001	1022	Clay Liner, Synth Cap, PCM,	\$113.53	\$209,974
00100001000110	1023	Synth Liner, LCS, Soil Cap, FA,	\$144.98	\$316,718
00010000000001	1024	Clay Liner, PCM,	\$110.59	\$202,168
00010000000001a	1024a	Clay Liner, PCM (PCM cost accrues after closure)	\$110.59	\$202,168
00000000000001	1025	PCM,	\$55.59	\$68,520
00000000000001a	1025a	PCM (PCM cost accrues after closure)	\$55.59	\$68,520
00100000000001	1026	Synth Liner, PCM,	\$124.12	\$233,373
00100000000001a	1026a	Synth Liner, PCM (PCM cost accrues after closure)	\$124.13	\$233,374
00000000100010	1027	Synth Cap, FA,	\$62.15	\$81,381
00100000100010	1028	Synth Liner, Synth Cap, FA,	\$130.68	\$246,234
00010000100010	1029	Clay Liner, Synth Cap, FA,	\$117.14	\$215,030
00100000000010	1030	Synth Liner, FA,	\$127.74	\$238,428
00010000000010	1031	Clay Liner, FA,	\$114.20	\$207,224
00000000100000	1032	Synth Cap,	\$58.52	\$72,200
00010000100000	1033	Clay Liner, Synth Cap,	\$113.52	\$205,848
00010000100000a	1033a	Clay Liner, Synth Cap (cap cost accrues after closure)	\$110.87	\$198,818
10000000000111	1034	UBM, Soil Cap, FA, PCM,	\$61.47	\$162,061
10010000000111	1035	UBM, Clay Liner, Soil Cap, FA, PCM,	\$116.46	\$295,709
00100001000001	1036	Synth Liner, LCS, PCM,	\$139.27	\$305,167
00100001000010	1037	Synth Liner, LCS, FA,	\$142.88	\$310,222
00100001100010	1038	Synth Liner, LCS, Synth Cap, FA,	\$145.83	\$318,028
10000101100011	30001	UBM, Yes Liner, LCS, Synth Cap, FA, PCM,	\$138.90	\$383,665
10000101100001	30002	UBM, Yes Liner, LCS, Synth Cap, PCM,	\$135.27	\$374,484
10000101010011	30003	UBM, Yes Liner, LCS, Clay Cap, FA, PCM,	\$140.81	\$388,895
10000101000111	30004	UBM, Yes Liner, LCS, Soil Cap, FA, PCM,	\$138.05	\$382,356
10000101000001	30005	UBM, Yes Liner, LCS, PCM,	\$132.34	\$366,678
10000101000000	30006	UBM, Yes Liner, LCS,	\$132.33	\$362,552
10000100100011	30007	UBM, Yes Liner, Synth Cap, FA, PCM,	\$123.75	\$311,871
10000100100001	30008	UBM, Yes Liner, Synth Cap, PCM,	\$120.13	\$302,707
10000100010011	30009	UBM, Yes Liner, Clay Cap, FA, PCM,	\$125.66	\$317,101

Exhibit D-3 Surface Impoundment Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (WET tons/yr) + Constant				
Controls Code	Cost Model Impoundment Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
10000100000100	30010	UBM, Yes Liner, Soil Cap,	\$119.28	\$297,254
10000100000011	30011	UBM, Yes Liner, FA, PCM,	\$120.82	\$304,065
10000100000010	30012	UBM, Yes Liner, FA,	\$120.81	\$299,939
10000100000001	30013	UBM, Yes Liner, PCM,	\$117.19	\$294,884
10000100000000	30014	UBM, Yes Liner,	\$117.18	\$290,758
01000100100011	30015	150m, Yes Liner, Synth Cap, FA, PCM,	\$123.75	\$335,590
01000100100001	30016	150m, Yes Liner, Synth Cap, PCM,	\$120.13	\$326,408
00000101100011	30017	Yes Liner, LCS, Synth Cap, FA, PCM,	\$138.74	\$305,818
00000101000000	30018	Yes Liner, LCS,	\$132.17	\$284,689
00000100100011	30019	Yes Liner, Synth Cap, FA, PCM,	\$123.59	\$234,008
00000100010000	30020	Yes Liner, Clay Cap,	\$121.87	\$225,930
00000100000100	30021	Yes Liner, Soil Cap,	\$119.12	\$219,391
00000100000000	30022	Yes Liner,	\$117.02	\$212,895
10000011100011	31001	UBM, Unknown Liner, LCS, Synth Cap, FA, PCM,	\$98.28	\$285,471
10000011100001	31002	UBM, Unknown Liner, LCS, Synth Cap, PCM,	\$94.65	\$276,290
10000011010011	31003	UBM, Unknown Liner, LCS, Clay Cap, FA, PCM,	\$100.18	\$290,701
10000011000111	31004	UBM, Unknown Liner, LCS, Soil Cap, FA, PCM,	\$97.43	\$284,162
10000011000001	31005	UBM, Unknown Liner, LCS, PCM,	\$91.71	\$268,484
10000011000000	31006	UBM, Unknown Liner, LCS,	\$91.71	\$264,358
10000010100011	31007	UBM, Unknown Liner, Synth Cap, FA, PCM,	\$83.13	\$213,676
10000010100001	31008	UBM, Unknown Liner, Synth Cap, PCM,	\$79.50	\$204,523
10000010010011	31009	UBM, Unknown Liner, Clay Cap, FA, PCM,	\$85.04	\$218,906
10000010000100	31010	UBM, Unknown Liner, Soil Cap,	\$78.65	\$199,059
10000010000011	31011	UBM, Unknown Liner, FA, PCM,	\$80.19	\$205,870
10000010000010	31012	UBM, Unknown Liner, FA,	\$80.18	\$201,745
10000010000001	31013	UBM, Unknown Liner, PCM,	\$76.57	\$196,689
10000010000001a	31013a	UBM, Unknown Liner, PCM (PCM cost accrues after closure)	\$76.57	\$196,690
10000010000000	31014	UBM, Unknown Liner,	\$76.56	\$192,564
01000010100011	31015	150m, Unknown Liner, Synth Cap, FA, PCM,	\$83.13	\$237,396
01000010100001	31016	150m, Unknown Liner, Synth Cap, PCM,	\$79.50	\$228,214
00000011100011	31017	Unknown Liner, LCS, Synth Cap, FA, PCM,	\$98.12	\$207,614
00000011000000	31018	Unknown Liner, LCS,	\$91.54	\$186,495
00000010100011	31019	Unknown Liner, Synth Cap, FA, PCM,	\$82.97	\$135,814
00000010010000	31020	Unknown Liner, Clay Cap,	\$81.24	\$127,736
00000010000100	31021	Unknown Liner, Soil Cap,	\$78.49	\$121,196

Exhibit D-3 Surface Impoundment Cost Equations (2011 \$/year) Linear Regression Annualized Cost Equations \$/yr = Rate x (WET tons/yr) + Constant				
Controls Code	Cost Model Impoundment Code	Controls Description	Rate Cost (\$/ton)	Constant (\$/yr)
00000010000000	31022	Unknown Liner,	\$76.40	\$114,700
00000010100001	31023	Unknown Liner, Synth Cap, PCM,	\$79.34	\$126,632
00000010100001a	31023a	Unknown Liner, Synth Cap, PCM (cap and PCM costs accrue after closure)	\$76.69	\$119,603
00000010000001	31024	Unknown Liner, PCM,	\$76.40	\$118,826
00000010000001a	31024a	Unknown Liner, PCM (PCM cost accrues after closure)	\$76.40	\$118,826
00000010100010	31025	Unknown Liner, Synth Cap, FA,	\$82.96	\$131,687
00000010000010	31026	Unknown Liner, FA,	\$80.02	\$123,881
10000011010011	31027	UBM, Unknown Liner, LCS, Clay Cap, FA, PCM,	\$100.18	\$290,701
00000010100000	31028	Unknown Liner, Synth Cap,	\$79.34	\$122,506
00000010100000	31028	Unknown Liner, Synth Cap,	\$76.69	\$115,476
00000010100000a	31028a	Unknown Liner, Synth Cap (cap cost accrues after closure)	\$76.69	\$115,476
10000010000111	31029	UBM, Unknown Liner, Soil Cap, FA, PCM,	\$82.28	\$212,367

APPENDIX E

Annual CCR Generation Forecast

Note: EPA has updated the projections used in this RIA to reflect the Base Case forecasts in the Integrated Planning Model. See **Section 9.2.2** in **Chapter 9** of this RIA for a description of the relevant modifications. This appendix has not been updated to reflect the revisions described in **Section 9.2.2**.

Annual CCR Generation Multiplier				
POA	Year	Data Source ¹	Quadrillion Btu Coal Consumption for Electricity Generation	Implied CCR Tonnage Generation Multiplier
-2	2012	DOE-EIA Data	15.82	1.000
-1	2013	DOE-EIA Data	16.96	1.072
0	2014	DOE-EIA Projection	17.33	1.096
1	2015	DOE-EIA Projection	17.04	1.078
2	2016	DOE-EIA Projection	16.06	1.016
3	2017	DOE-EIA Projection	16.45	1.040
4	2018	DOE-EIA Projection	16.82	1.064
5	2019	DOE-EIA Projection	16.96	1.073
6	2020	DOE-EIA Projection	16.95	1.072
7	2021	DOE-EIA Projection	17.05	1.078
8	2022	DOE-EIA Projection	17.14	1.084
9	2023	DOE-EIA Projection	17.16	1.085
10	2024	DOE-EIA Projection	17.32	1.095
11	2025	DOE-EIA Projection	17.41	1.101
12	2026	DOE-EIA Projection	17.41	1.101
13	2027	DOE-EIA Projection	17.45	1.103
14	2028	DOE-EIA Projection	17.45	1.104
15	2029	DOE-EIA Projection	17.46	1.104
16	2030	DOE-EIA Projection	17.44	1.103
17	2031	DOE-EIA Projection	17.42	1.101
18	2032	DOE-EIA Projection	17.39	1.100
19	2033	DOE-EIA Projection	17.38	1.099
20	2034	DOE-EIA Projection	17.35	1.097
21	2035	DOE-EIA Projection	17.32	1.095
22	2036	DOE-EIA Projection	17.33	1.096
23	2037	DOE-EIA Projection	17.30	1.094
24	2038	DOE-EIA Projection	17.30	1.094
25	2039	DOE-EIA Projection	17.29	1.093
26	2040	Not projected by EIA	17.27	1.092
27	2041	Not projected by EIA	17.27	1.092
28	2042	Not projected by EIA	17.27	1.092
29	2043	Not projected by EIA	17.27	1.092
30	2044	Not projected by EIA	17.27	1.092
31	2045	Not projected by EIA	17.27	1.092
32	2046	Not projected by EIA	17.27	1.092
33	2047	Not projected by EIA	17.27	1.092
34	2048	Not projected by EIA	17.27	1.092
35	2049	Not projected by EIA	17.27	1.092
36	2050	Not projected by EIA	17.27	1.092
37	2051	Not projected by EIA	17.27	1.092
38	2052	Not projected by EIA	17.27	1.092
39	2053	Not projected by EIA	17.27	1.092
40	2054	Not projected by EIA	17.27	1.092
41	2055	Not projected by EIA	17.27	1.092
42	2056	Not projected by EIA	17.27	1.092
43	2057	Not projected by EIA	17.27	1.092
44	2058	Not projected by EIA	17.27	1.092

Annual CCR Generation Multiplier				
POA	Year	Data Source¹	Quadrillion Btu Coal Consumption for Electricity Generation	Implied CCR Tonnage Generation Multiplier
45	2059	Not projected by EIA	17.27	1.092
46	2060	Not projected by EIA	17.27	1.092
47	2061	Not projected by EIA	17.27	1.092
48	2062	Not projected by EIA	17.27	1.092
49	2063	Not projected by EIA	17.27	1.092
50	2064	Not projected by EIA	17.27	1.092
51	2065	Not projected by EIA	17.27	1.092
52	2066	Not projected by EIA	17.27	1.092
53	2067	Not projected by EIA	17.27	1.092
54	2068	Not projected by EIA	17.27	1.092
55	2069	Not projected by EIA	17.27	1.092
56	2070	Not projected by EIA	17.27	1.092
57	2071	Not projected by EIA	17.27	1.092
58	2072	Not projected by EIA	17.27	1.092
59	2073	Not projected by EIA	17.27	1.092
60	2074	Not projected by EIA	17.27	1.092
61	2075	Not projected by EIA	17.27	1.092
62	2076	Not projected by EIA	17.27	1.092
63	2077	Not projected by EIA	17.27	1.092
64	2078	Not projected by EIA	17.27	1.092
65	2079	Not projected by EIA	17.27	1.092
66	2080	Not projected by EIA	17.27	1.092
67	2081	Not projected by EIA	17.27	1.092
68	2082	Not projected by EIA	17.27	1.092
69	2083	Not projected by EIA	17.27	1.092
70	2084	Not projected by EIA	17.27	1.092
71	2085	Not projected by EIA	17.27	1.092
72	2086	Not projected by EIA	17.27	1.092
73	2087	Not projected by EIA	17.27	1.092
74	2088	Not projected by EIA	17.27	1.092
75	2089	Not projected by EIA	17.27	1.092
76	2090	Not projected by EIA	17.27	1.092
77	2091	Not projected by EIA	17.27	1.092
78	2092	Not projected by EIA	17.27	1.092
79	2093	Not projected by EIA	17.27	1.092
80	2094	Not projected by EIA	17.27	1.092
81	2095	Not projected by EIA	17.27	1.092
82	2096	Not projected by EIA	17.27	1.092
83	2097	Not projected by EIA	17.27	1.092
84	2098	Not projected by EIA	17.27	1.092
85	2099	Not projected by EIA	17.27	1.092
86	2100	Not projected by EIA	17.27	1.092
87	2101	Not projected by EIA	17.27	1.092
88	2102	Not projected by EIA	17.27	1.092
89	2103	Not projected by EIA	17.27	1.092
90	2104	Not projected by EIA	17.27	1.092
91	2105	Not projected by EIA	17.27	1.092

Annual CCR Generation Multiplier				
POA	Year	Data Source¹	Quadrillion Btu Coal Consumption for Electricity Generation	Implied CCR Tonnage Generation Multiplier
92	2106	Not projected by EIA	17.27	1.092
93	2107	Not projected by EIA	17.27	1.092
94	2108	Not projected by EIA	17.27	1.092
95	2109	Not projected by EIA	17.27	1.092
96	2110	Not projected by EIA	17.27	1.092
97	2111	Not projected by EIA	17.27	1.092
98	2112	Not projected by EIA	17.27	1.092
99	2113	Not projected by EIA	17.27	1.092
100	2114	Not projected by EIA	17.27	1.092

APPENDIX F

QA/QC of 2012 EIA-923 CCR Final Disposition Quantities

Appendix F: QA/QC of 2012 EIA-923 CCR Final Disposition Quantities

This appendix summarizes the methodology used and results from conducting QA/QC of the coal combustion residual (CCR) annual byproducts disposition quantities reported in the 2012 U.S. Department of Energy (DOE) Energy Information Administration (EIA) Form EIA-923 database on “Power Plant Operations” (www.eia.gov). We compared the 2012 EIA-923 data from Schedule 8 Part A Annual Byproduct Disposition with the 2009 EIA-923 data to identify outlier quantities. The quantities reported for fly ash, bottom ash, FGP/gypsum, and other were compared. There were numerous cases where quantities differed by greater than +/- 100,000 tons. In the end, we focused on conducting QA/QC of outlier quantities exceeding 500,000 tons (> 0.4% of the total CCR reported by all 478 coal-fired electric utility plants). Twelve (12) plants had reported a difference exceeding 500,000 tons between 2009 and 2012 for either fly ash, bottom ash, FGP/gypsum, and other (Plant Identification Numbers 628, 2840, 2850, 3149, 3179, 6018, 6180, 6213, 6648, 8823, 54081, and 56808). After reviewing data for these 12 plants and internet sources there are no recommended changes the 2012 EIA-923 quantities reported. The big differences can be explained by the site being a new plant (6180 and 56808), reporting FGD quantities differently between the FGD Gypsum and Other FGD reporting categories (2840, 6018, and 6213), new FGD equipment installed (628, 3149, and 3179), and consistent reporting with prior years (6648 and 8223). For one plant (2850), after review of the numbers a clear conclusion could not be drawn why the fly ash quantity dropped significantly while other numbers did not change correspondingly to warrant making any changes. One plant’s quantities (54081) differed by about a factor of 10 between 2012 and 2009. The same conclusion is drawn when you compare the 2005, 2005, 2007, 2008, 2010, and 2011 quantities with the 2009 quantities. It appears the quantities reported for this facility in 2009 are a factor of 10 too high. This does not affect the 2012 EIA data used in this RIA.

Total CCR Generation for Plant Identification Number 54081 (1,000 tons)

PLANT ID	Category	Total 2005	Total_2007	Total_2008	Total_2009	Corrected Total_2009	Total_2010	Total_2011	Total_2012
54081	Bottom Ash	67	65	71	569	56.9	79.6	69.2	34
54081	Other FGD	86	91	84	946	94.6	104.5	88.3	54
54081	Fly Ash	5	5	7	69	6.9	10.5	5	3
54081	FGD Gypsum	0	0	0	0	0	0	0	0

Total Coal Usage for Plant Identification Number 54081

Coal Type	2007 Tons	2008 Tons	2009 Tons	2010 Tons	2011 Tons	2012 Tons
BIT	828,555	866,753	663,218	753,111	665.153	361,641

APPENDIX G

Baseline State Government Regulatory Requirements for CCR Disposal Units in Top-34 Coal Utility States

Exhibit G-1: Minimum State Groundwater Monitoring Requirements for CCR Landfills

Exhibit G-2: Minimum State Groundwater Monitoring Requirements for CCR Impoundments

Exhibit G-3: Minimum State Pollution Control Requirements for CCR Landfills for the Top-34 Coal Utility States

Exhibit G-4: Minimum State Pollution Control Requirements for CCR Impoundments for the Top-34 Coal Utility States

Exhibit G-1 Minimum State Groundwater Monitoring Requirements for CCR Landfills for Top 34 Coal Utility States ⁵							
State	Date of Regulation	Monitoring Required	Monitoring Location	Minimum No. Wells	Sampling Parameters	Monitoring Frequency	Post-closure Monitoring
AL (new unit construction only)	7/26/1996 5/5/2011	Yes	unit boundary ¹				Yes
AZ	None	No					No
CO	10/9/93 ⁴	Yes	unit boundary ¹				Yes
FL (new unit construction only)	1/6/93 ⁴ Amended 1/6/2010	Yes	unit boundary		indicator & Appendix VIII	semi-annual	Yes
GA	7/1/91 ⁴	Yes	unit boundary ¹		Appendix VIII	semi-annual	Yes
IA	1971 - 2007 ⁴ (several amendments)	Yes	unit boundary ¹	1	indicator & Appendix VIII	quarterly (until baseline conditions established) annual (after baseline established)	Yes
IL (new units replacing units that existed before 10/9/93)	9/18/90 ⁴ Amended 11/27/2007	Yes	unit boundary ¹	multiple	Appendix VIII	quarterly (first 5 years) annual (after 5 years)	Yes
IN (In compliance by 1/1/98)	9/1/89 ⁴ 4/14/1996 (for closure)	Yes	unit boundary ¹				No
KS	5/79 ⁴ (amended 5/82 through 7/11)	Yes Discretionary; but, NODA 1 says required.					No Discretionary
KY	7/1/1993	Yes		3	indicator	semi-annual	Yes
LA	5/3/2003 (Amend 2008)	Yes NODA 1	unit boundary ¹	3		semi-annual	Yes
MD	1987 9/16/2002	No Discretionary					Yes
MI (In compliance by 4/19/97)	10/8/93 ⁴	Yes NODA 1 says required at all	unit boundary ¹		indicator & Appendix VIII	quarterly	Yes

Exhibit G-1
Minimum State Groundwater Monitoring Requirements for CCR Landfills for Top 34 Coal Utility States ⁵

State	Date of Regulation	Monitoring Required	Monitoring Location	Minimum No. Wells	Sampling Parameters	Monitoring Frequency	Post-closure Monitoring
		units					
MN	6/95 ⁴ (adopted 1988)	Yes	unit boundary ¹	2			Yes
MS	2/22/1996	Yes	unit boundary ¹	2			Yes
MO	9/97 ⁴	Yes	unit boundary ¹	4	Appendix VIII	semi-annual	Yes
MT	6/30/1997	Yes	unit boundary ¹	3	indicator & Appendix VIII	semi-annual	Yes
NC	10/1/1995 ⁴	Yes	unit boundary ¹				No
ND	12/1/1992 ⁴ through 11/02	Yes Discretionary; but, NODA 1 says required.	unit boundary ¹				Yes
NM	None Excluded from definition of solid waste.	No					No
NV	11/8/1993	Yes	unit boundary ¹	3	Appendix VIII	semi-annual	Yes
NY	Adopted 1988 Amended 2006	Yes	unit boundary ¹	4	indicator	annual	Yes
OH	6/1/1994 Amended 2009	Yes	unit boundary ¹	2	indicator & Appendix VIII	semi-annual (for indicators) annual (for metals, TOC, TDS, chloride, sodium and radionuclides)	Yes
OK	6/1/1994 ⁴	Yes	unit boundary ¹	4	indicator	semi-annual	Yes
PA	7/4/1992	Yes	unit boundary	4	indicator	quarterly (for indicators) annual (for metals and VOCs)	Yes
SC	10/25/2002 Amended 5/23/2008	Yes NODA 1 says CCR is Class 3	unit boundary ¹	2	indicator	semi-annual	Yes

Exhibit G-1
Minimum State Groundwater Monitoring Requirements for CCR Landfills for Top 34 Coal Utility States ⁵

State	Date of Regulation	Monitoring Required	Monitoring Location	Minimum No. Wells	Sampling Parameters	Monitoring Frequency	Post-closure Monitoring
		waste and it is required					
TN	3/18/1990 ⁴ Amended May 2010	Yes	unit boundary ¹	3	indicator & Appendix VIII	semi-annual (for indicators) annual (Appendix VIII constituents)	Yes
TX	None	No					No
UT	7/15/1999 Amended 2/1/2007	Yes		3	indicator & Appendix VIII	semi-annual	Yes
VA	3/16/2011	Yes	unit boundary ¹			semi-annual	Yes
WA	9/8/2000	Yes	unit boundary ¹	4	indicator	quarterly	Yes
WI (new units constructed after 7/1/96)	Aug 1997	No Discretionary			indicator	semi-annual	Yes
WV (new unit construction only)	5/1/1990 ⁴	Yes	unit boundary ¹	4	indicator & Appendix VIII	semi-annual	Yes
WY	11/28/1990 Amended 5/25/1995, 12/15/1998	Yes NODA 1 indicates it is required.	unit boundary ¹		Appendix VIII	semi-annual	Yes

Notes:

1. State regulations regarding monitoring were non-specific. In cases where a specific locations for groundwater monitoring was unavailable or given as within a distance from the waste placement (e.g., "within 500 feet"), Unit Boundary Monitoring was assumed as the least cost alternative. The assumption of Unit Boundary Monitoring may increase the estimated post closure remediation costs.
2. The definition for "solid waste" in the regulations indicates that it does not include fly ash waste from coal combustion/energy production (Title 20, Chapter 9, subpart 1, 105(BV)(2)). No regulations were found for fly ash waste from coal combustion/energy production.
3. Not used.
4. The date of regulation was retained from the review of state regulations prepared by SAIC Incorporated and submitted to the Municipal, Industrial and Solid Waste Division, Office of Solid Waste, on November 15, 2000.
5. Even though a "no" is specified for a particular pollution control requirement, the State may require the pollution control as a condition under the permit.

Exhibit G-2

Minimum State Groundwater Monitoring Requirements for CCR Surface Impoundments for Top 34 Coal Utility States

State	Date of Regulation	Required Monitoring	Monitoring Location	Minimum No. Wells	Sampling Parameters	Monitoring Frequency	Post-closure Monitoring
AL	None	No					No
AZ	9/27/1989 1/1/04 ²	No		S			Yes
CO (new unit construction only)	8/9/93 ² 4/4/1997	Yes	unit boundary ¹		indicator	quarterly or annual (depending on groundwater classification)	Yes
FL (new unit construction only)	7/1/1982 1/6/1993 Amended 1/6/2010	Yes	unit boundary ¹	3			No
GA	None	No					No
IA	None	No					No
IL	None	No					No
IN	None	No					No
KS	Revised 7/2011	Yes Discretionary; but, NODA 1 says required.					No Discretionary
KY	None	No					No
LA	5/1/2003 (Amend 2008)	Yes	unit boundary ¹	3		semi-annual	Yes
MD	None	No					No
MI	10/8/93 ² (monitoring)	Yes NODA 1 says required at all units	unit boundary ¹ (if unlined)	NODA 1 says that newly permitted facilities have 3-6 up gradient and 5-15 down gradient	indicator	quarterly during operations and biannually post operation	Yes
MN	None	No					No
MS	None	No					No
MO	None	No					No

Exhibit G-2

Minimum State Groundwater Monitoring Requirements for CCR Surface Impoundments for Top 34 Coal Utility States

State	Date of Regulation	Required Monitoring	Monitoring Location	Minimum No. Wells	Sampling Parameters	Monitoring Frequency	Post-closure Monitoring
MT	None	No					No
NC	None	No					No
ND	12/1/92 ²	Yes	unit boundary ¹	3		semi-annual	Yes
NM	None Excluded from definition of solid waste.	No					No
NV	11/8/1993	Yes	unit boundary ¹				Yes
NY	Adopted 1988 Amended 2006	Yes	unit boundary ¹	3	indicator	annual	Yes
OH	None	No					No
OK	6/12/2000	No Discretionary, NODA 1 says no SIs in OK	unit boundary ¹	3			No Discretionary
PA	1/13/2001	Yes	unit boundary ¹	4	indicator & Appendix VIII	quarterly (for indicators); annual (for metals & VOCs)	Yes
SC	Effective 4/25/2008	No Discretionary per NODA 1 and regs	unit boundary ¹				Yes NODA 1 indicates required for SIs
TN	None	No					No
TX	None	No					No
UT	None	No					No
VA	3/16/2011	Yes	unit boundary ¹			semi-annual	Yes
WA	9/8/2000	Yes		4	indicator	quarterly	Yes
WI	Aug-97	No Discretionary					No Discretionary
WV (new unit construction only)	5/1/1990	Yes	unit boundary ¹	4	indicator & Appendix VIII	semi-annual	Yes

Exhibit G-2**Minimum State Groundwater Monitoring Requirements for CCR Surface Impoundments for Top 34 Coal Utility States**

State	Date of Regulation	Required Monitoring	Monitoring Location	Minimum No. Wells	Sampling Parameters	Monitoring Frequency	Post-closure Monitoring
WY	None	No Discretionary according to NODA 1					Yes NODA 1 indicates required

Notes:

1. State regulations regarding monitoring were non-specific. In cases where a specific locations for groundwater monitoring was unavailable or given as within a distance from the waste placement (e.g., “within 500 feet”), Unit Boundary Monitoring was assumed as the least cost alternative. The assumption of Unit Boundary Monitoring may increase the estimated post closure remediation costs.
2. The date of regulation was retained from the review of state regulations prepared by SAIC Incorporated and submitted to the Municipal, Industrial and Solid Waste Division, Office of Solid Waste, on November 15, 2000.

Exhibit G-3 Minimum State Pollution Control Requirements for CCR Landfills for the Top 34 Coal Utility States								
State	Date of Regulation	Liner?	Leachate Collection System?	Cap?	Financial Assurance?*	Daily Cover?	Dust Controls?	Run-on/Run-off Controls?
AL (new unit construction only)	7/26/1996 5/5/2011	composite	Y	synthetic	Y	Y	N	N
AZ	None	N	N	N	N	N	N	N
CO (new unit construction for liner and LCS only; all units meet remaining requirements)	10/9/93 ⁴ 4/9/1997 for financial assurance	clay or synthetic	Y	clay or synthetic	Y	N	Y	Y
FL (new unit construction only)	1/6/93 ⁴ (amended 1/6/10)	composite or double	Y	synthetic	Y	Y	Y	Y
GA (new unit construction after 10/9/93 for liner and LCS; all units meet remaining requirements)	7/1/91 ⁴ 10/9/93	composite	Y	soil	Y	Y	Y compaction	Y
IA (new unit construction after 2007 for liners and LCS only)	1971-2007 ⁴ (several amend.)	Y	Y	Soil	Y	N	Y	Y
IL (new unit construction after 10/9/93 for liner and LCS; all units meet remaining requirements)	9/18/90 ⁴ 10/9/93	clay or composite	Y	New: clay or synthetic Existing: Soil	Y	Y	Y Compaction	Y
IN (In compliance by 1/1/98)	9/1/89 ⁴ 4/14/96 for closure	clay	Y karst only	clay	Y	N	Y	Y
KS (MSWLF regulated, no regulations listed for industrial landfills)	5/79 ⁴ (amended 5/82 through 7/2011)	N	N	N	Y NODA 1 comment	N	N	N
KY	7/1/1993	N Discretionary	N Discretionary	Y	Y	Y	N	N Discretionary
LA	5/1/2003 (amended 2008)	composite	Y	clay	Y	Y	Y	Y
MD (new unit construction after	9/16/2002 (Amended 2008)	clay or synthetic	Y	clay or synthetic	N	Y	N	Y

Exhibit G-3 Minimum State Pollution Control Requirements for CCR Landfills for the Top 34 Coal Utility States								
State	Date of Regulation	Liner?	Leachate Collection System?	Cap?	Financial Assurance?*	Daily Cover?	Dust Controls?	Run-on/Run-off Controls?
1/1/08)								
MI (In compliance by April 19, 1997; new units or expansions need financial assurance for most closure costs)	10/8/93 ⁴	composite	Y	clay or synthetic	Y	Y	Y	N
MN	6/1995 ⁴	clay	Y	clay	Y	Y	Y compaction	Y
MS (new unit construction after 10/9/91 must meet liner and LCS requirements; all units meet remaining requirements)	2/22/1996	composite	Y	soil	Y	Y	N	Y
MO (new units constructed after 10/9/93, except all units must comply with remaining requirements)	9/1997 ⁴	composite	Y	soil	Y	Y	Y	Y
MT (new units constructed after 10/9/93, except all units meet remaining requirements)	6/30/1997	composite	Y	soil	Y	Y	N	Y
NC (new units constructed after 1/1/98, except all units must comply with cap reqs)	10/1/95 ⁴ effective; 1/1/98 compliance	composite	Y	soil	N	N	N	N
ND	12/1/92 ⁴	N	N	clay	Y	N	Y compaction	No
NM ²	None Excluded from definition of solid waste.	N	N	N	N	N	N	N
NV (new units after 1993 meet liner and LCS requirements; all units meet remaining	11/8/1993	composite	Y	New: clay or synthetic Existing: soil	Y	Y	Y	Y

Exhibit G-3 Minimum State Pollution Control Requirements for CCR Landfills for the Top 34 Coal Utility States								
State	Date of Regulation	Liner?	Leachate Collection System?	Cap?	Financial Assurance?*	Daily Cover?	Dust Controls?	Run-on/Run-off Controls?
requirements)								
NY (new units after 1993 meet liner and LCS requirements; all units meet remaining requirements)	Adopted 1988 Amended 1993	composite	Y	New: synthetic Existing: soil	Y	Y	Y	Y
OH	6/1/94 (design criteria/ monitoring) 3/1/96 (operating criteria) Amended 2009	clay	Y	synthetic	Y	Y	Y	Y
OK (new unit construction only for liner and LCS requirements; all units meet remaining requirements)	6/1/93 ⁴ Amended 7/11/10	composite	Y	New: clay Existing: soil	Y	N	Y	Y
PA	1/13/2001	N	N	clay or synthetic	Y	Y	Y	Y
SC	10/25/2002 Amended 5/23/2008	clay	Y	clay	Y	Y	Y	Y
TN	3/18/90 ⁴ Amended May 2010	composite	Y	clay	Y	Y	Y	Y
TX	None	N	N	N	N	N	N	N
UT	7/15/1999 Amended 2/1/2007	N	N	soil	Y	Y	Y	Y
VA (new units after 1993 meet liner, LCS and cap requirements; all units meet remaining requirements; pre 1993 assume soil cap)	3/16/2011 or 8/3/2011	clay or synthetic	Y	New: clay or synthetic Existing: soil	Y	Y	Y	Y
WA	9/8/2000	clay for western WA and None for arid eastern	Y	clay for western WA and None for arid eastern	Y	N	Y	Y

Exhibit G-3 Minimum State Pollution Control Requirements for CCR Landfills for the Top 34 Coal Utility States								
State	Date of Regulation	Liner?	Leachate Collection System?	Cap?	Financial Assurance?*	Daily Cover?	Dust Controls?	Run-on/Run-off Controls?
		WA		WA				
WI (new units constructed after 7/1/96)	Aug-97	composite	Y	clay	Y	N	Y	Y
WV (new unit construction, liner and LCS required after 5/1/90)	5/1/90 ⁴ Amended 5/1/10	composite	Y	clay	Y	Y	Y	Y
WY (new unit construction, except existing units must meet cap, FA, and dust reqs.)	10/15/1998	clay	Y	clay	Y	N	Y	Y
Notes: * Information on financial assurance requirements was collected in accordance with earlier proposed requirements of the CCR rule. This RIA does not model costs of complying with financial assurance either in the baseline or under the final CCR rule scenario. 1. Not used. 2. The definition for “solid waste” in the regulations indicates that it does not include fly ash waste from coal combustion/energy production (Title 20, Chapter 9, subpart 1, 105(BV)(2)). No regulations were found for fly ash waste from coal combustion/energy production. 3. Not used. 4. Date of regulation retained from the review of state regulations prepared by SAIC Inc for the Municipal, Industrial & Solid Waste Division, EPA OSW, 15 Nov 2000.								

Exhibit G-4
Minimum State Pollution Control Requirements for CCR Surface Impoundments for the Top 34 Coal Utility States

State	Date of Regulation	Liner	Leachate Collection System*	Cap	Financial Assurance**	Run-on/Run-off Controls
AL	None	N	N	N	N	N
AZ	None	N	N	N	Y	N
CO (For new unit construction only)	8/9/93 ¹ 4/9/1997 11/12/2005	clay or soil deposit	Y	clay or synthetic	Y	N
FL	None	N	N	N	N	N
GA	None	N	N	N	N	N
IA	None	N	N	N	N	N
IL	None	N	N	N	N	N
IN	None	N	N	N	N	N
KS	None	N	N	N	N	N
KY	None	N	N	N	N	N
LA (New unit construction requires liners after 12/31/97; all other controls apply to existing and new units)	5/1/2003 (amended 2007)	composite	N	clay (if solid waste remains)	Y	Y
MD	None	N	N	N	N	N
MI (For units constructed after 1978)	10/8/93 ¹ (monitoring) 8/26/1999 (liner requirements)	clay or composite NODA 1 says required	Y	clay or synthetic	Y	Y
MN	None	N	N	N	N	N
MS	None	N	N	N	N	N
MO	None	N	N	N	N	N
MT	None	N	N	N	N	N
NC (For new unit construction only.)	1/4/1994	composite	Y	soil	Y	N
ND	12/1/92 ¹	clay or synthetic	Y	clay	Y	Y
NM	None - excluded from definition of solid waste.	N	N	N	N	N

Exhibit G-4
Minimum State Pollution Control Requirements for CCR Surface Impoundments for the Top 34 Coal Utility States

State	Date of Regulation	Liner	Leachate Collection System*	Cap	Financial Assurance**	Run-on/Run-off Controls
NV	11/8/1993	composite	Y	clay or synthetic	Y	N
NY (new units after 1993 meet liner and LCS requirements)	Adopted 1988 Amended 1993	composite	Y	N	N	N
OH	None	N	N	N	N	N
OK	7/1/95 ¹ Amended 6/12/2000	composite	N	clay or synthetic	N	Y
PA (new unit construction only for liner and LCS requirements; all units meet remaining requirements)	1/13/2001	composite	Y	clay or synthetic	Y	Y
SC	None	N	N	N	N	N
TN	None	N	N	synthetic	Y	N
TX	None	N	N	N	N	N
UT	None	N	N	N	Y	N
VA (new units after 1993 meet liner, LCS and cap requirements; all units meet remaining requirements; pre 1993 assume soil cap)	3/16/2011 or 8/3/2011	clay or synthetic	Y	New: clay or synthetic Existing: soil	Y	Y
WA	9/8/2000	clay	N	clay for western WA and None for arid eastern WA	Y	Y
WI (For new unit construction only)	Aug-97	soil or synthetic	N	N	N	N
WV (For new unit construction only after 5/1/1990)	5/1/1990 Amended 5/1/10	composite	Y	N	N	N
WY	None	N NODA 1 says Discretionary	N	N	N	N

Notes: Y = yes; N = no.

* As indicated in **Chapters 3 and 4** of the RIA, this RIA assumes that where applicable, leachate collection systems for surface impoundments are actually leachate *detection* systems. Because the final CCR rule does not require leachate collection systems for surface impoundments, this requirement is only modeled where it is present due to a state regulatory baseline.

Exhibit G-4 Minimum State Pollution Control Requirements for CCR Surface Impoundments for the Top 34 Coal Utility States						
State	Date of Regulation	Liner	Leachate Collection System*	Cap	Financial Assurance**	Run-on/Run-off Controls
** Information on financial assurance requirements was collected in accordance with earlier proposed requirements of the CCR rule. This RIA does not model costs of complying with financial assurance either in the baseline or under the final CCR rule scenario. 1. The date of regulation was retained from the review of state regulations prepared by SAIC Incorporated and submitted to the Municipal, Industrial and Solid Waste Division, Office of Solid Waste, on November 15, 2000.						

APPENDIX H

List of Pollution Controls by Unit: State Regulatory Baseline

Note: EPA has updated the baseline cost calculations presented in this RIA to conform with changes to the universe of plants affected by the rule and the analytic framework. See **Sections 9.2 and 9.4 in Chapter 9** of this RIA for a description of the relevant modifications and the resultant re-estimated costs, respectively. Exhibits in this appendix have not been updated to reflect the revisions described in **Sections 9.2 and 9.4**.

Exhibit H-1: List of Pollution Controls for Each of the 310 Landfills (New Unit Construction)

Exhibit H-2: List of Pollution Controls for Each of the 310 Landfills (Existing Units)

Exhibit H-3: List of Pollution Controls for Each of the 735 Surface Impoundments
(New Unit Construction)

Exhibit H-4: List of Pollution Controls for Each of the 735 Surface Impoundments
(Existing Units)

Note: dust controls and run-on/run-off controls not included in Exhibit H-3 and Exhibit H-4 as this RIA assumes that these pollution controls are not required under any state regulatory baseline.

Exhibit H-1
List of Engineering Controls for Each of the 310 Landfills (New Unit Construction)

State	Plant Code	Landfill ID	Plant Name	Groundwater Monitoring	Liner					Leachate Collection System	Cap			Dust Controls	Run-on/Run-off	Post Closure Monitoring
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Soil			
AL	8	LANDFILL	Gorgas	Y	Y	N	N	N	N	Y	Y	N	N	N	N	Y
AL	47	LANDFILL-1	Colbert	Y	Y	N	N	N	N	Y	Y	N	N	N	N	Y
AL	56	LANDFILL	Charles R. Lowman	Y	Y	N	N	N	N	Y	Y	N	N	N	N	Y
AR	6009	LANDFILL-1	White Bluff	N	N	N	N	Y	N	N	N	N	N	N	N	N
AR	6138	LANDFILL-1	Flint Creek	N	N	N	N	Y	N	Y	N	N	N	N	N	N
AR	6641	LANDFILL-1	Independence	N	N	Y	N	N	N	N	N	Y	N	N	N	N
AZ	113	LANDFILL-1	Cholla	N	N	N	N	N	N	Y	N	N	N	N	N	N
AZ	4941	LANDFILL-1	Navajo Generating Station	N	N	N	N	N	N	N	N	N	N	N	N	N
AZ	6177	LANDFILL-1	Coronado Generating Station	N	N	N	N	N	N	Y	N	Y	N	N	N	N
AZ	8223	LANDFILL-1	Springerville	N	N	N	N	N	N	N	N	N	Y	N	N	N
CA	10002	LANDFILL	ACE Cogeneration Company	N	N	N	N	N	Y	N	N	N	N	N	N	N
CO	470	LANDFILL-1	Comanche	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
CO	477	LANDFILL-1	Valmont	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
CO	492	LANDFILL-1	Martin Drake	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
CO	525	LANDFILL-1	Hayden	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
CO	527	LANDFILL	Nucla	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
CO	6248	LANDFILL-1	Pawnee	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
CO	6761	LANDFILL-1	Rawhide	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
CO	6761	No Answer	Rawhide	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
CO	8219	LANDFILL-1	Ray D Nixon	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
DE	594	LANDFILL-1	Indian River Generating Station	N	N	N	N	Y	N	N	N	N	N	N	N	N
FL	136	LANDFILL-1	Seminole Generating Station	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
FL	207	LANDFILL-2	St Johns River Power Park	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
FL	207	LANDFILL-3	St Johns River Power Park	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
FL	564	LANDFILL-1	Stanton Energy Center	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
FL	628	LANDFILL-1	Crystal River Power Plant	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
FL	641	LANDFILL-1	Crist	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
FL	643	LANDFILL-1	Lansing Smith	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
FL	645	LANDFILL-1	Big Bend	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
FL	663	LANDFILL-1	Deerhaven Generating Station	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
FL	667	LANDFILL-1	Northside Generating Station	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
FL	676	LANDFILL-1	C D McIntosh Jr	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
FL	7242	LANDFILL-1	Polk	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
GA	703	LANDFILL-1	Bowen	Y	Y	N	N	N	N	Y	N	N	Y	Y	Y	Y
GA	708	LANDFILL-1	Hammond	Y	Y	N	N	N	N	Y	N	N	Y	Y	Y	Y
GA	710	LANDFILL	Jack McDonough	Y	Y	N	N	N	N	Y	N	N	Y	Y	Y	Y
GA	728	LANDFILL-1	Yates	Y	Y	N	N	N	N	Y	N	N	Y	Y	Y	Y
GA	728	LANDFILL-2	Yates	Y	Y	N	N	N	N	Y	N	N	Y	Y	Y	Y
GA	733	LANDFILL-1	Kraft	Y	Y	N	N	N	N	Y	N	N	Y	Y	Y	Y
IA	1047	LANDFILL-1	Lansing	Y	N	Y	N	N	N	Y	N	N	Y	Y	Y	Y
IA	1082	LANDFILL-1	Walter Scott Jr. Energy Center	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
IA	1091	LANDFILL-1	George Neal North	Y	N	N	N	Y	N	Y	N	N	Y	Y	Y	Y
IA	1091	LANDFILL-2	George Neal North	Y	N	Y	N	N	N	Y	N	N	Y	Y	Y	Y
IA	1091	LANDFILL-3	George Neal North	Y	N	Y	N	N	N	Y	N	N	Y	Y	Y	Y
IA	1131	LANDFILL-1	Streeter Station	Y	N	Y	N	N	N	Y	N	N	Y	Y	Y	Y
IA	1167	LANDFILL-1	Muscatine #1	Y	N	N	N	Y	N	Y	N	N	Y	Y	Y	Y
IA	1217	LANDFILL-1	Earl F Wisdom	Y	N	Y	N	N	N	Y	N	N	Y	Y	Y	Y
IA	6254	LANDFILL-1	Ottumwa	Y	N	N	N	Y	N	Y	N	N	Y	Y	Y	Y
IA	6664	LANDFILL-1	Louisa	Y	N	Y	N	N	N	Y	N	N	Y	Y	Y	Y
IA	7343	LANDFILL-1	George Neal South	Y	N	Y	N	N	N	Y	N	N	Y	Y	Y	Y

Exhibit H-1 List of Engineering Controls for Each of the 310 Landfills (New Unit Construction)																
State	Plant Code	Landfill ID	Plant Name	Groundwater Monitoring	Liner					Leachate Collection System	Cap			Dust Controls	Run-on/Run-off	Post Closure Monitoring
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Soil			
IL	384	LANDFILL	Joliet 29	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
IL	861	LANDFILL-1	Coffeen	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
IL	876	LANDFILL	Kincaid Generation LLC	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
IL	887	LANDFILL-1	Joppa Steam	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
IL	892	LANDFILL-1	Hennepin Power Station	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
IL	963	LANDFILL-1	Dallman	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
IL	976	LANDFILL-1	Marion Generating Station	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
IL	6016	LANDFILL-1	Duck Creek	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
IL	6017	LANDFILL-1	Newton	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
IN	983	LANDFILL-1	Clifty Creek	Y	N	Y	N	N	N	Y	N	Y	N	Y	Y	N
IN	983	LANDFILL-2	Clifty Creek	Y	N	N	N	Y	N	Y	N	Y	N	Y	Y	N
IN	988	LANDFILL-1	Tanners Creek	Y	N	N	N	Y	N	Y	N	Y	N	Y	Y	N
IN	994	LANDFILL-1	AES Petersburg	Y	N	N	N	Y	N	Y	N	Y	N	Y	Y	N
IN	1001	LANDFILL-1	Cayuga	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	N
IN	1004	LANDFILL	Edwardsport	Y	N	Y	N	N	N	Y	N	Y	N	Y	Y	N
IN	1008	LANDFILL-1	R. Gallagher	Y	N	Y	N	N	N	Y	N	Y	N	Y	Y	N
IN	1008	LANDFILL-2	R. Gallagher	Y	N	Y	N	N	N	Y	N	Y	N	Y	Y	N
IN	1008	LANDFILL-3	R. Gallagher	Y	N	Y	N	N	N	Y	N	Y	N	Y	Y	N
IN	1008	LANDFILL-4	R. Gallagher	Y	N	Y	N	N	N	Y	N	Y	N	Y	Y	N
IN	1008	No Answer	R. Gallagher	Y	N	Y	N	N	N	Y	N	Y	N	Y	Y	N
IN	6085	LANDFILL-1	R.M. Schahfer	Y	N	N	N	Y	N	Y	N	Y	N	Y	Y	N
IN	6113	LANDFILL-1	Gibson	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	N
IN	6113	LANDFILL-2	Gibson	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	N
IN	6137	LANDFILL-1	A. B. Brown Generating Station	Y	N	N	N	Y	N	Y	N	Y	N	Y	Y	N
IN	6166	LANDFILL-1	Rockport	Y	N	N	N	Y	N	Y	N	Y	N	Y	Y	N
IN	6213	LANDFILL-1	Merom	Y	N	N	N	Y	N	Y	N	Y	N	Y	Y	N
KS	108	LANDFILL-1	HOLCOMB	Y	N	N	N	N	N	Y	N	N	N	N	N	N
KS	1241	LANDFILL-1	La Cygne	Y	N	N	N	Y	N	N	N	N	N	N	N	N
KS	1250	LANDFILL-1	Lawrence Energy Center	Y	N	N	N	N	N	N	N	N	N	N	N	N
KS	1250	LANDFILL-2	Lawrence Energy Center	Y	N	N	N	Y	N	Y	N	N	N	N	N	N
KS	1252	-999	Tecumseh Energy Center	Y	N	N	N	N	Y	N	N	Y	N	N	N	N
KS	1252	LANDFILL-1	Tecumseh Energy Center	Y	N	N	N	N	N	N	N	N	N	N	N	N
KS	1295	LANDFILL-1	Quindaro	Y	N	N	N	Y	N	N	N	N	N	N	N	N
KS	6064	LANDFILL-1	Nearman Creek	Y	N	N	N	Y	N	N	N	N	N	N	N	N
KS	6064	LANDFILL-2	Nearman Creek	Y	N	N	N	N	N	N	N	N	N	N	N	N
KS	6068	LANDFILL-1	Jeffrey Energy Center	Y	N	N	N	N	N	N	N	N	N	N	N	N
KS	6068	LANDFILL-2	Jeffrey Energy Center	Y	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1363	LANDFILL-1	Cane Run	Y	N	N	N	N	N	N	Y	N	N	N	N	Y
KY	1364	LANDFILL-1	Mill Creek	Y	N	N	N	N	N	N	Y	N	N	N	N	Y
KY	1364	LANDFILL-2	Mill Creek	Y	N	N	N	Y	N	Y	Y	N	N	N	N	Y
KY	1364	LANDFILL-3	Mill Creek	Y	N	N	N	N	N	N	Y	N	N	N	N	Y
KY	1379	LANDFILL-1	Shawnee	Y	N	N	N	N	N	N	Y	N	N	N	N	Y
KY	1379	LANDFILL-2	Shawnee	Y	N	N	N	N	Y	N	Y	N	N	N	N	Y
KY	1382	LANDFILL	HMP&L Station Two Henderson	Y	N	N	N	N	Y	N	Y	N	N	N	N	Y
KY	1384	LANDFILL	Cooper Station.	Y	N	N	N	N	Y	N	Y	N	N	N	N	Y
KY	6018	LANDFILL-1	East Bend Station	Y	N	N	N	Y	N	Y	Y	N	N	N	N	Y
KY	6041	LANDFILL-1	H L Spurlock Station	Y	N	Y	N	N	N	N	Y	N	N	N	N	Y
KY	6639	LANDFILL-1	R D Green	Y	N	N	N	N	N	Y	Y	N	N	N	N	Y
KY	6823	LANDFILL-1	D B Wilson	Y	N	N	N	N	N	N	Y	N	N	N	N	Y
KY	6823	LANDFILL-2	D B Wilson	Y	N	N	N	N	N	N	Y	N	N	N	N	Y

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List of Engineering Controls for Each of the 310 Landfills (New Unit Construction)																
State	Plant Code	Landfill ID	Plant Name	Groundwater Monitoring	Liner					Leachate Collection System	Cap			Dust Controls	Run-on/Run-off	Post Closure Monitoring
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Soil			
LA	51	LANDFILL-1	Dolet Hills	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
LA	1393	LANDFILL-1	RS Nelson	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
LA	1393	LANDFILL-2	RS Nelson	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
LA	6055	LANDFILL-1	Big Cajun 2	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
MA	1619	LANDFILL-1	Brayton Point	N	N	N	N	Y	N	Y	N	N	N	N	N	N
MD	1570	LANDFILL-1	R. Paul Smith Power Station	N	N	N	N	Y	N	Y	Y	N	N	N	Y	Y
MD	1571	LANDFILL-1	Chalk Point LLC	N	N	N	N	Y	N	Y	Y	N	N	N	Y	Y
MD	1571	LANDFILL-2	Chalk Point LLC	N	N	N	N	Y	N	Y	Y	N	N	N	Y	Y
MD	1572	LANDFILL-2	Dickerson	N	N	N	N	Y	N	Y	Y	N	N	N	Y	Y
MD	1573	LANDFILL-1	Morgantown Generating Plant	N	N	N	N	Y	N	Y	Y	N	N	N	Y	Y
MD	1573	LANDFILL-2	Morgantown Generating Plant	N	N	N	N	Y	N	Y	Y	N	N	N	Y	Y
MI	1702	LANDFILL-1	D.E. Karn	Y	Y	N	N	N	N	Y	Y	N	N	Y	N	Y
MI	1710	LANDFILL-1	Consumers Energy - J.H. Campbell	Y	Y	N	N	N	N	Y	Y	N	N	Y	N	Y
MI	1710	LANDFILL-2	Consumers Energy - J.H. Campbell	Y	Y	N	N	N	N	Y	Y	N	N	Y	N	Y
MI	1710	LANDFILL-3	Consumers Energy - J.H. Campbell	Y	Y	N	N	N	N	Y	Y	N	N	Y	N	Y
MI	1710	LANDFILL-4	Consumers Energy - J.H. Campbell	Y	Y	N	N	N	N	Y	Y	N	N	Y	N	Y
MI	1720	LANDFILL-1	J.C. Weadock	Y	Y	N	N	N	N	Y	Y	N	N	Y	N	Y
MI	1745	LANDFILL-1	Trenton Channel Power Plant	Y	Y	N	N	N	N	Y	Y	N	N	Y	N	Y
MI	1769	LANDFILL-1	Presque Isle	Y	Y	N	N	N	N	Y	Y	N	N	Y	N	Y
MI	1830	LANDFILL-1	James De Young	Y	Y	N	N	N	N	Y	Y	N	N	Y	N	Y
MI	6034	LANDFILL-1	Belle River	Y	Y	N	N	N	N	Y	Y	N	N	Y	N	Y
MN	1893	LANDFILL-1	Boswell Energy Center	Y	N	Y	N	N	N	Y	N	Y	N	Y	Y	Y
MN	1893	LANDFILL-2	Boswell Energy Center	Y	N	Y	N	N	N	Y	N	Y	N	Y	Y	Y
MN	1915	LANDFILL-1	Allen S King	Y	N	N	N	Y	N	Y	N	Y	N	Y	Y	Y
MN	1943	LANDFILL-1	Hoot Lake	Y	N	Y	N	N	N	Y	N	Y	N	Y	Y	Y
MN	1943	LANDFILL-2	Hoot Lake	Y	N	Y	N	N	N	Y	N	Y	N	Y	Y	Y
MN	1943	LANDFILL-3	Hoot Lake	Y	N	N	N	Y	N	Y	N	Y	N	Y	Y	Y
MN	6090	LANDFILL-1	Sherburne County	Y	N	N	N	Y	N	Y	N	Y	N	Y	Y	Y
MN	10075	LANDFILL-1	Taconite Harbor Energy Center	Y	N	N	N	Y	N	Y	N	Y	N	Y	Y	Y
MN	10075	LANDFILL-2	Taconite Harbor Energy Center	Y	N	N	N	Y	N	Y	N	Y	N	Y	Y	Y
MN	10075	LANDFILL-3	Taconite Harbor Energy Center	Y	N	N	N	Y	N	Y	N	Y	N	Y	Y	Y
MO	2079	LANDFILL	Hawthorn	Y	Y	N	N	N	N	Y	N	N	Y	Y	Y	Y
MO	2080	LANDFILL-1	Montrose	Y	Y	N	N	N	N	Y	N	N	Y	Y	Y	Y
MO	2094	LANDFILL-1	Sibley	Y	Y	N	N	N	N	Y	N	N	Y	Y	Y	Y
MO	2161	LANDFILL-1	James River Power Station	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
MO	2167	LANDFILL-1	New Madrid	Y	Y	N	N	N	N	Y	N	N	Y	Y	Y	Y
MO	2168	LANDFILL-1	Thomas Hill	Y	Y	N	N	N	N	Y	N	N	Y	Y	Y	Y
MO	6065	LANDFILL-1	Iatan	Y	Y	N	N	N	N	Y	N	N	Y	Y	Y	Y
MO	6195	LANDFILL-1	Southwest Power Station	Y	Y	N	N	N	N	Y	N	N	Y	Y	Y	Y
MS	2049	LANDFILL-1	Jack Watson	Y	Y	N	N	N	N	Y	N	N	Y	N	Y	Y
MS	6061	LANDFILL-1	South Mississippi El Pwr Assn	Y	Y	N	N	N	N	Y	N	N	Y	N	Y	Y
MS	6061	LANDFILL-2	South Mississippi El Pwr Assn	Y	Y	N	N	N	N	Y	N	N	Y	N	Y	Y
MS	6061	LANDFILL-3	South Mississippi El Pwr Assn	Y	Y	N	N	N	N	Y	N	N	Y	N	Y	Y
MS	6073	LANDFILL-1	Victor J. Daniel Jr	Y	Y	N	N	N	N	Y	N	N	Y	N	Y	Y
MS	6073	LANDFILL-2	Victor J. Daniel Jr	Y	Y	N	N	N	N	Y	N	N	Y	N	Y	Y
MS	55076	LANDFILL-1	Red Hills Generating Facility	Y	Y	N	N	N	N	Y	N	N	Y	N	Y	Y
MT	6089	LANDFILL-1	Lewis & Clark	Y	Y	N	N	N	N	Y	N	N	Y	N	Y	Y
MT	10784	LANDFILL-1	Colstrip Energy LP	Y	Y	N	N	N	N	Y	N	N	Y	N	Y	Y
NC	2712	LANDFILL-1	Roxboro Steam Electric Plant	Y	Y	N	N	N	N	Y	N	N	Y	N	N	N
NC	2718	LANDFILL-1	G G Allen	Y	Y	N	N	N	N	Y	N	N	Y	N	N	N

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State	Plant Code	Landfill ID	Plant Name	Groundwater Monitoring	Liner					Leachate Collection System	Cap			Dust Controls	Run-on/Run-off	Post Closure Monitoring
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Soil			
NC	2727	LANDFILL-1	Marshall	Y	Y	N	N	N	N	Y	N	N	Y	N	N	N
NC	8042	LANDFILL-1	Belews Creek Steam Station	Y	Y	N	N	N	N	Y	N	N	Y	N	N	N
NC	8042	LANDFILL-2	Belews Creek Steam Station	Y	Y	N	N	N	N	Y	N	N	Y	N	N	N
ND	2790	LANDFILL-1	R.M. Heskett Station	Y	N	N	N	Y	N	Y	N	Y	N	Y	N	Y
ND	2817	LANDFILL-1	Leland Olds	Y	N	N	N	N	N	N	N	Y	N	Y	N	Y
ND	2817	LANDFILL-2	Leland Olds	Y	N	N	N	Y	N	N	N	Y	N	Y	N	Y
ND	2823	LANDFILL-1	Milton R. Young Station	Y	N	N	N	Y	N	Y	N	Y	N	Y	N	Y
ND	2823	LANDFILL-2	Milton R. Young Station	Y	N	N	N	N	N	Y	N	Y	N	Y	N	Y
ND	2824	LANDFILL-1	Stanton	Y	N	Y	N	N	N	Y	N	Y	N	Y	N	Y
ND	2824	LANDFILL-2	Stanton	Y	N	Y	N	N	N	N	N	Y	N	Y	N	Y
ND	6030	LANDFILL-1	Coal Creek	Y	N	N	N	Y	N	N	N	Y	N	Y	N	Y
ND	6030	LANDFILL-2	Coal Creek	Y	N	N	N	Y	N	N	N	Y	N	Y	N	Y
ND	6030	LANDFILL-3	Coal Creek	Y	N	N	N	Y	N	N	N	Y	N	Y	N	Y
ND	6469	LANDFILL-1	Antelope Valley Station	Y	N	Y	N	N	N	N	N	Y	N	Y	N	Y
ND	6469	LANDFILL-2	Antelope Valley Station	Y	N	Y	N	N	N	N	N	Y	N	Y	N	Y
ND	8222	LANDFILL-1	Coyote	Y	N	Y	N	N	N	N	N	Y	N	Y	N	Y
ND	8222	LANDFILL-2	Coyote	Y	N	N	N	N	N	N	N	Y	N	Y	N	Y
NE	59	LANDFILL-1	Platte	N	N	N	N	N	N	N	N	N	N	N	N	N
NE	2240	LANDFILL-1	Lon Wright	N	N	N	N	Y	N	Y	N	N	N	N	N	N
NE	2277	LANDFILL-1	Sheldon Station	N	N	N	N	Y	N	Y	N	N	N	N	N	N
NE	2291	LANDFILL-1	North Omaha	N	N	N	N	N	N	N	N	N	N	N	N	N
NE	6077	LANDFILL-1	Gerald Gentleman	N	N	N	N	Y	N	N	N	N	N	N	N	N
NE	6096	LANDFILL-1	Nebraska City	N	N	N	N	N	N	N	N	N	N	N	N	N
NE	6096	LANDFILL-2	Nebraska City	N	N	N	N	Y	N	Y	N	N	N	N	N	N
NH	2364	LANDFILL-1	Merrimack Station	N	N	N	N	Y	N	Y	N	N	N	N	N	N
NJ	2403	LANDFILL-1	PSEG Hudson Generating Station	N	N	N	N	N	N	N	N	N	N	N	N	N
NJ	2408	LANDFILL-1	PSEG Mercer Generating Station	N	N	N	N	N	N	N	N	N	N	N	N	N
NM	87	LANDFILL-1	Escalante	N	N	Y	N	N	N	N	N	N	Y	N	N	N
NM	2442	LANDFILL-1	Four Corners	N	N	N	N	Y	N	Y	N	N	N	N	N	N
NM	2442	LANDFILL-2	Four Corners	N	N	N	N	N	N	N	N	N	N	N	N	N
NV	2324	LANDFILL-1	Reid Gardner	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
NV	8224	LANDFILL-1	North Valmy	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
NV	56224	LANDFILL	TS Power Plant	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
NY	2527	LANDFILL-1	AES Greenidge	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
NY	2535	LANDFILL-1	AES Cayuga, LLC	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
NY	2549	LANDFILL-1	CR Huntley Generating Station	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
NY	2554	LANDFILL-1	Dunkirk Generating Plant	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
NY	6082	LANDFILL-1	AES Somerset LLC	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
OH	2828	LANDFILL-1	Cardinal	Y	N	N	N	Y	N	Y	Y	N	N	Y	Y	Y
OH	2830	LANDFILL-1	Walter C Beckjord	Y	N	Y	N	N	N	Y	Y	N	N	Y	Y	Y
OH	2832	LANDFILL-1	Miami Fort	Y	N	N	N	Y	N	Y	Y	N	N	Y	Y	Y
OH	2836	LANDFILL	Avon Lake	Y	N	Y	N	N	N	Y	Y	N	N	Y	Y	Y
OH	2837	LANDFILL-1	Eastlake	Y	N	N	N	Y	N	Y	Y	N	N	Y	Y	Y
OH	2840	LANDFILL-1	Conesville	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
OH	2850	LANDFILL-1	J M Stuart	Y	N	N	N	Y	N	Y	Y	N	N	Y	Y	Y
OH	2850	LANDFILL-2	J M Stuart	Y	N	N	N	Y	N	Y	Y	N	N	Y	Y	Y
OH	2866	LANDFILL-1	W. H. Sammis	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
OH	2876	LANDFILL-1	Kyger Creek	Y	N	N	N	Y	N	Y	Y	N	N	Y	Y	Y
OH	2878	LANDFILL	Bay Shore	Y	N	Y	N	N	N	Y	Y	N	N	Y	Y	Y
OH	6019	LANDFILL-1	W H Zimmer	Y	N	N	N	Y	N	Y	Y	N	N	Y	Y	Y

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					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Soil			
OH	8102	LANDFILL-1	General James M. Gavin	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
OK	165	LANDFILL-1	GRDA	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
OK	2963	LANDFILL-1	Northeastern	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
OK	6772	LANDFILL-1	Hugo	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
OR	6106	LANDFILL-1	Boardman	N	N	N	N	N	N	N	N	N	N	N	N	N
PA	3113	LANDFILL-1	Portland	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
PA	3115	LANDFILL-1	Titus	Y	N	N	N	N	N	Y	Y	N	N	Y	Y	Y
PA	3118	LANDFILL-1	Conemaugh	Y	N	N	N	Y	N	Y	Y	N	N	Y	Y	Y
PA	3122	LANDFILL-1	Homer City Station	Y	N	N	N	N	N	Y	Y	N	N	Y	Y	Y
PA	3122	LANDFILL-2	Homer City Station	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
PA	3131	LANDFILL-1	Shawville	Y	N	N	N	Y	N	Y	Y	N	N	Y	Y	Y
PA	3136	LANDFILL-1	Keystone	Y	N	N	N	Y	N	Y	Y	N	N	Y	Y	Y
PA	3136	LANDFILL-2	Keystone	Y	N	N	N	Y	N	Y	Y	N	N	Y	Y	Y
PA	3138	LANDFILL-1	New Castle Plant	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
PA	3140	LANDFILL-1	PPL Brunner Island	Y	N	N	N	Y	N	Y	Y	N	N	Y	Y	Y
PA	3149	LANDFILL-1	PPL Montour	Y	N	N	N	Y	N	Y	Y	N	N	Y	Y	Y
PA	3178	LANDFILL-1	Armstrong Power Station	Y	N	N	N	Y	N	Y	Y	N	N	Y	Y	Y
PA	3179	LANDFILL-1	Hatfield's Ferry Power Station	Y	N	N	N	N	N	Y	Y	N	N	Y	Y	Y
PA	3181	LANDFILL-1	Mitchell Power Station	Y	N	N	N	N	N	Y	Y	N	N	Y	Y	Y
PA	8226	LANDFILL-1	Cheswick Power Plant	Y	N	N	N	Y	N	Y	Y	N	N	Y	Y	Y
PA	10343	LANDFILL-1	Foster Wheeler Mt Carmel Cogen	Y	N	N	N	N	Y	Y	Y	N	N	Y	Y	Y
SC	130	LANDFILL-1	Cross	Y	N	Y	N	N	N	Y	N	Y	N	Y	Y	Y
SC	130	LANDFILL-2	Cross	Y	N	Y	N	N	N	Y	N	Y	N	Y	Y	Y
SC	130	LANDFILL-3	Cross	Y	N	Y	N	N	N	Y	N	Y	N	Y	Y	Y
SC	130	LANDFILL-4	Cross	Y	N	Y	N	N	N	Y	N	Y	N	Y	Y	Y
SC	3287	LANDFILL-1	McMeekin	Y	N	Y	N	N	N	Y	N	Y	N	Y	Y	Y
SC	3295	LANDFILL-1	Urquhart	Y	N	Y	N	N	N	Y	N	Y	N	Y	Y	Y
SC	3297	LANDFILL-1	Wateree	Y	N	N	N	Y	N	Y	N	Y	N	Y	Y	Y
SC	3298	LANDFILL-1	Williams	Y	N	N	N	Y	N	Y	N	Y	N	Y	Y	Y
SC	3298	LANDFILL-2	Williams	Y	N	N	N	Y	N	Y	N	Y	N	Y	Y	Y
SC	6249	LANDFILL	Winyah	Y	N	Y	N	N	N	Y	N	Y	N	Y	Y	Y
SC	7210	LANDFILL-1	Cope	Y	N	Y	N	N	N	Y	N	Y	N	Y	Y	Y
SD	6098	LANDFILL-1	Big Stone	N	N	N	N	N	N	N	N	N	N	N	N	N
TN	3396	LANDFILL-1	Bull Run	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
TN	3399	LANDFILL	Cumberland	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
TN	3405	LANDFILL-1	John Sevier	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
TN	3406	LANDFILL-1	Johnsonville	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
TX	127	LANDFILL	Oklaunion	N	N	N	N	N	Y	N	N	N	N	N	N	N
TX	298	LANDFILL-1	Limestone	N	N	N	N	Y	N	Y	N	N	N	N	N	N
TX	3470	LANDFILL-1	W. A. Parish	N	N	N	N	Y	N	N	N	N	N	N	N	N
TX	3497	LANDFILL-1	Big Brown	N	N	Y	N	N	N	N	N	Y	N	N	N	N
TX	6136	LANDFILL-1	Gibbons Creek Steam Electric Station	N	N	N	N	Y	N	Y	N	N	N	N	N	N
TX	6136	LANDFILL-2	Gibbons Creek Steam Electric Station	N	N	N	N	Y	N	Y	N	N	N	N	N	N
TX	6139	LANDFILL-1	Welsh	N	N	N	N	N	N	N	N	N	N	N	N	N
TX	6146	LANDFILL-1	Martin Lake	N	N	N	N	Y	N	Y	N	N	N	N	N	N
TX	6147	LANDFILL-1	Monticello	N	N	N	N	N	N	N	N	N	N	N	N	N
TX	6147	LANDFILL-2	Monticello	N	N	N	N	Y	N	N	N	N	N	N	N	N
TX	6179	LANDFILL-2	Fayette Power Project	N	N	N	N	Y	N	N	N	N	N	N	N	N
TX	6180	LANDFILL-1	Oak Grove	N	N	N	N	Y	N	N	N	N	N	N	N	N
TX	6180	LANDFILL-2	Oak Grove	N	N	N	N	N	N	N	N	N	N	N	N	N

Exhibit H-1
List of Engineering Controls for Each of the 310 Landfills (New Unit Construction)

State	Plant Code	Landfill ID	Plant Name	Groundwater Monitoring	Liner					Leachate Collection System	Cap			Dust Controls	Run-on/Run-off	Post Closure Monitoring
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Soil			
TX	6180	LANDFILL-3	Oak Grove	N	N	N	N	N	N	N	N	N	N	N	N	N
TX	6181	LANDFILL-1	J T Deely	N	N	N	N	Y	N	N	N	N	N	N	N	N
TX	6181	LANDFILL-2	J T Deely	N	N	N	N	N	Y	N	N	N	N	N	N	N
TX	6183	LANDFILL-1	San Miguel	N	N	N	N	Y	N	N	N	N	N	N	N	N
TX	6193	LANDFILL-1	Harrington	N	N	N	N	Y	N	N	N	N	N	N	N	N
TX	6193	LANDFILL-2	Harrington	N	N	N	N	Y	N	N	N	N	N	N	N	N
TX	6194	LANDFILL-4	Tolk	N	N	N	N	N	N	N	N	N	N	N	N	N
TX	6648	LANDFILL-1	Sandow No 4	N	N	Y	N	N	N	N	N	N	N	N	N	N
TX	6648	LANDFILL-2	Sandow No 4	N	N	N	N	N	N	N	N	N	N	N	N	N
TX	6648	LANDFILL-3	Sandow No 4	N	N	N	N	N	N	N	N	N	N	N	N	N
TX	6648	LANDFILL-4	Sandow No 4	N	N	N	N	N	N	N	N	N	N	N	N	N
TX	7030	LANDFILL-1	Twin Oaks Power One	N	N	N	N	Y	N	Y	N	N	N	N	N	N
TX	7097	LANDFILL-1	J K Spruce	N	N	N	N	Y	N	N	N	N	N	N	N	N
TX	7902	LANDFILL-1	Pirkey	N	Y	N	N	N	N	N	N	N	Y	N	N	N
UT	3644	LANDFILL-1	Carbon Plant	Y	N	N	N	N	N	N	N	N	Y	Y	Y	Y
UT	6165	LANDFILL-1	Hunter Plant	Y	N	N	N	N	N	N	N	N	Y	Y	Y	Y
UT	7790	LANDFILL-1	Bonanza Power Plant	Y	N	N	N	N	N	N	N	Y	N	Y	Y	Y
UT	7790	LANDFILL-2	Bonanza Power Plant	Y	N	N	N	N	N	N	N	N	Y	Y	Y	Y
UT	8069	LANDFILL-1	Huntington Plant	Y	N	N	N	N	N	N	N	N	Y	Y	Y	Y
UT	8069	LANDFILL-2	Huntington Plant	Y	N	N	N	N	N	N	N	N	Y	Y	Y	Y
UT	50951	LANDFILL-1	Sunnyside Cogen Associates	Y	N	N	N	N	N	N	N	N	Y	Y	Y	Y
VA	3775	LANDFILL-1	Clinch River	Y	N	N	N	Y	N	Y	Y	N	N	Y	Y	Y
VA	3776	LANDFILL-1	Glen Lyn	Y	N	N	N	Y	N	Y	Y	N	N	Y	Y	Y
VA	3803	LANDFILL-1	Chesapeake Energy Center	Y	N	N	N	Y	N	Y	Y	N	N	Y	Y	Y
VA	3809	LANDFILL-1	Yorktown	Y	N	Y	N	N	N	Y	Y	N	N	Y	Y	Y
VA	7213	LANDFILL-1	Clover	Y	Y	N	N	N	N	Y	Y	N	N	Y	Y	Y
WA	3845	LANDFILL-1	TransAlta Centralia Generation	Y	N	N	N	Y	N	Y	N	N	N	Y	Y	Y
WI	3982	LANDFILL-1	Bay Front	N	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WI	4041	LANDFILL-1	South Oak Creek	N	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WI	4042	LANDFILL-1	Valley	N	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WI	4042	LANDFILL-2	Valley	N	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WI	4050	LANDFILL-1	Edgewater	N	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WI	4078	LANDFILL-1	Weston	N	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WI	4140	LANDFILL-1	Alma	N	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WI	4143	LANDFILL-1	Genoa	N	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WI	4271	LANDFILL-1	John P. Madgett	N	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WI	6170	LANDFILL-1	Pleasant Prairie	N	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WI	8023	LANDFILL-1	Columbia	N	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WV	3935	LANDFILL-1	John E. Amos	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WV	3935	LANDFILL-2	John E. Amos	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WV	3938	LANDFILL	Philip Sporn	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WV	3942	LANDFILL-1	Albright Power Station	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WV	3943	LANDFILL-1	Fort Martin Power Station	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WV	3943	LANDFILL-2	Fort Martin Power Station	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WV	3944	LANDFILL-1	Harrison Power Station	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WV	3945	LANDFILL-1	Rivesville Power Station	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WV	3946	LANDFILL-1	Willow Island	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WV	3954	LANDFILL-1	Mt. Storm	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WV	3954	LANDFILL-2	Mt. Storm	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WV	3954	LANDFILL-3	Mt. Storm	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y

Exhibit H-1																
List of Engineering Controls for Each of the 310 Landfills (New Unit Construction)																
State	Plant Code	Landfill ID	Plant Name	Groundwater Monitoring	Liner					Leachate Collection System	Cap			Dust Controls	Run-on/Run-off	Post Closure Monitoring
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Soil			
WV	6004	LANDFILL-1	Pleasants Power Station	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WV	6264	LANDFILL-1	Mountaineer	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WV	10151	LANDFILL-1	Grant Town Power Plant	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WV	10151	LANDFILL-2	Grant Town Power Plant	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WV	10151	LANDFILL-3	Grant Town Power Plant	Y	Y	N	N	N	N	Y	N	Y	N	Y	Y	Y
WY	4158	LANDFILL-1	Dave Johnston Plant	Y	N	Y	N	N	N	Y	N	Y	N	Y	Y	Y
WY	4162	LANDFILL	Naughton Plant	Y	N	Y	N	N	N	Y	N	Y	N	Y	Y	Y
WY	6101	LANDFILL	Wyodak Plant	Y	N	Y	N	N	N	Y	N	Y	N	Y	Y	Y
WY	6204	LANDFILL-1	Laramie River Station	Y	N	Y	N	N	N	Y	N	Y	N	Y	Y	Y
WY	8066	LANDFILL-1	Jim Bridger Plant Units 1-4	Y	N	Y	N	N	N	Y	N	Y	N	Y	Y	Y

Exhibit H-2
List of Engineering Controls for Each of the 310 Landfills (Existing Units)

State	Plant Code	Landfill ID	Plant Name	Groundwater Monitoring	Liner				Leachate Collection System	Cap			Dust Controls	Run-on/Run-off	Post Closure Monitoring
					Synthetic	Clay	Yes	Unknown		Synthetic	Clay	Soil			
AL	8	LANDFILL	Gorgas	N	N	N	N	Y	N	N	N	N	N	N	N
AL	47	LANDFILL-1	Colbert	N	N	N	N	N	N	N	N	N	N	N	N
AL	56	LANDFILL	Charles R. Lowman	N	N	N	N	Y	N	N	N	N	N	N	N
AR	6009	LANDFILL-1	White Bluff	N	N	N	Y	N	N	N	N	N	N	N	N
AR	6138	LANDFILL-1	Flint Creek	N	N	N	Y	N	Y	N	N	N	N	N	N
AR	6641	LANDFILL-1	Independence	N	N	Y	N	N	N	N	N	N	N	N	N
AZ	113	LANDFILL-1	Cholla	N	N	N	N	N	Y	N	N	N	N	N	N
AZ	4941	LANDFILL-1	Navajo Generating Station	N	N	N	N	N	N	N	N	N	N	N	N
AZ	6177	LANDFILL-1	Coronado Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
AZ	8223	LANDFILL-1	Springerville	N	N	N	N	N	N	N	N	N	N	N	N
CA	10002	LANDFILL	ACE Cogeneration Company	N	N	N	N	Y	N	N	N	N	N	N	N
CO	470	LANDFILL-1	Comanche	Y	N	N	N	N	N	N	N	N	Y	Y	N
CO	477	LANDFILL-1	Valmont	Y	N	N	N	N	N	N	N	N	Y	Y	N
CO	492	LANDFILL-1	Martin Drake	Y	N	N	N	N	N	N	N	N	Y	Y	N
CO	525	LANDFILL-1	Hayden	Y	N	N	N	N	N	N	N	N	Y	Y	N
CO	527	LANDFILL	Nucla	Y	N	N	N	Y	N	N	N	N	Y	Y	N
CO	6248	LANDFILL-1	Pawnee	Y	N	N	N	N	N	N	N	N	Y	Y	N
CO	6761	LANDFILL-1	Rawhide	Y	N	N	N	N	N	N	N	N	Y	Y	N
CO	6761	No Answer	Rawhide	Y	N	N	N	Y	N	N	N	N	Y	Y	N
CO	8219	LANDFILL-1	Ray D Nixon	Y	N	N	N	N	N	N	N	N	Y	Y	N
DE	594	LANDFILL-1	Indian River Generating Station	N	N	N	Y	N	N	N	N	N	N	N	N
FL	136	LANDFILL-1	Seminole Generating Station	N	N	N	Y	N	Y	N	N	N	N	N	N
FL	207	LANDFILL-2	St Johns River Power Park	Y	N	N	N	N	N	N	N	N	Y	Y	N
FL	207	LANDFILL-3	St Johns River Power Park	Y	N	N	N	N	N	N	N	N	Y	Y	N
FL	564	LANDFILL-1	Stanton Energy Center	N	N	N	N	N	N	N	N	N	N	N	N
FL	628	LANDFILL-1	Crystal River Power Plant	N	N	N	N	N	N	N	N	N	N	N	N
FL	641	LANDFILL-1	Crist	N	N	N	Y	N	Y	N	N	N	N	N	N
FL	643	LANDFILL-1	Lansing Smith	N	N	N	Y	N	N	N	N	N	N	N	N
FL	645	LANDFILL-1	Big Bend	N	N	N	N	N	Y	N	N	N	N	N	N
FL	663	LANDFILL-1	Deerhaven Generating Station	N	N	N	Y	N	Y	N	N	N	N	N	N
FL	667	LANDFILL-1	Northside Generating Station	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
FL	676	LANDFILL-1	C D McIntosh Jr	N	N	N	N	N	N	N	N	N	N	N	N
FL	7242	LANDFILL-1	Polk	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
GA	703	LANDFILL-1	Bowen	Y	N	N	Y	N	N	N	N	N	Y	Y	N
GA	708	LANDFILL-1	Hammond	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
GA	710	LANDFILL	Jack McDonough	Y	N	N	N	Y	N	N	N	N	Y	Y	N
GA	728	LANDFILL-1	Yates	Y	N	N	N	N	N	N	N	N	Y	Y	N
GA	728	LANDFILL-2	Yates	Y	N	N	Y	N	N	N	N	N	Y	Y	N
GA	733	LANDFILL-1	Kraft	Y	N	N	N	N	N	N	N	N	Y	Y	N
IA	1047	LANDFILL-1	Lansing	Y	N	N	N	N	N	N	N	N	Y	Y	N
IA	1082	LANDFILL-1	Walter Scott Jr. Energy Center	Y	Y	N	N	N	Y	N	N	N	Y	Y	N
IA	1091	LANDFILL-1	George Neal North	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
IA	1091	LANDFILL-2	George Neal North	Y	N	N	N	Y	N	N	N	N	Y	Y	N
IA	1091	LANDFILL-3	George Neal North	Y	N	N	N	Y	N	N	N	N	Y	Y	N
IA	1131	LANDFILL-1	Streeter Station	Y	N	N	N	N	N	N	N	N	Y	Y	N
IA	1167	LANDFILL-1	Muscatine #1	Y	N	N	Y	N	N	N	N	N	Y	Y	N
IA	1217	LANDFILL-1	Earl F Wisdom	Y	N	N	N	N	N	N	N	N	Y	Y	N
IA	6254	LANDFILL-1	Ottumwa	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
IA	6664	LANDFILL-1	Louisa	Y	N	N	N	N	N	N	N	N	Y	Y	N
IA	7343	LANDFILL-1	George Neal South	Y	N	N	N	N	N	N	N	N	Y	Y	N
IL	384	LANDFILL	Joliet 29	N	N	N	N	Y	N	N	N	N	Y	Y	N

Exhibit H-2
List of Engineering Controls for Each of the 310 Landfills (Existing Units)

State	Plant Code	Landfill ID	Plant Name	Groundwater Monitoring	Liner				Lechate Collection System	Cap			Dust Controls	Run-on/Run-off	Post Closure Monitoring
					Synthetic	Clay	Yes	Unknown		Synthetic	Clay	Soil			
IL	861	LANDFILL-1	Coffeen	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
IL	876	LANDFILL	Kincaid Generation LLC	N	N	N	N	Y	N	N	N	N	Y	Y	N
IL	887	LANDFILL-1	Joppa Steam	N	N	N	Y	N	Y	N	N	N	Y	Y	N
IL	892	LANDFILL-1	Hennepin Power Station	N	N	N	Y	N	Y	N	N	N	Y	Y	N
IL	963	LANDFILL-1	Dallman	N	N	N	Y	N	Y	N	N	N	Y	Y	N
IL	976	LANDFILL-1	Marion Generating Station	N	N	N	N	N	N	N	N	N	Y	Y	N
IL	6016	LANDFILL-1	Duck Creek	Y	Y	N	N	N	Y	N	N	N	Y	Y	N
IL	6017	LANDFILL-1	Newton	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
IN	983	LANDFILL-1	Clifty Creek	Y	N	N	N	N	N	N	N	N	Y	Y	N
IN	983	LANDFILL-2	Clifty Creek	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
IN	988	LANDFILL-1	Tanners Creek	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
IN	994	LANDFILL-1	AES Petersburg	Y	N	N	Y	N	N	N	N	N	Y	Y	N
IN	1001	LANDFILL-1	Cayuga	Y	Y	N	N	N	Y	N	N	N	Y	Y	N
IN	1004	LANDFILL	Edwardsport	Y	N	N	N	Y	Y	N	N	N	Y	Y	N
IN	1008	LANDFILL-1	R. Gallagher	Y	N	N	N	Y	Y	N	N	N	Y	Y	N
IN	1008	LANDFILL-2	R. Gallagher	Y	N	N	N	Y	Y	N	N	N	Y	Y	N
IN	1008	LANDFILL-3	R. Gallagher	Y	N	N	N	Y	Y	N	N	N	Y	Y	N
IN	1008	LANDFILL-4	R. Gallagher	Y	N	N	N	Y	Y	N	N	N	Y	Y	N
IN	1008	No Answer	R. Gallagher	Y	N	N	N	Y	Y	N	N	N	Y	Y	N
IN	6085	LANDFILL-1	R.M. Schahfer	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
IN	6113	LANDFILL-1	Gibson	Y	Y	N	N	N	Y	N	N	N	Y	Y	N
IN	6113	LANDFILL-2	Gibson	Y	Y	N	N	N	Y	N	N	N	Y	Y	N
IN	6137	LANDFILL-1	A. B. Brown Generating Station	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
IN	6166	LANDFILL-1	Rockport	Y	N	N	Y	N	N	N	N	N	Y	Y	N
IN	6213	LANDFILL-1	Merom	Y	N	N	Y	N	N	N	N	N	Y	Y	N
KS	108	LANDFILL-1	HOLCOMB	Y	N	N	N	N	Y	N	N	N	N	N	N
KS	1241	LANDFILL-1	La Cygne	Y	N	N	Y	N	N	N	N	N	N	N	N
KS	1250	LANDFILL-1	Lawrence Energy Center	Y	N	N	N	N	N	N	N	N	N	N	N
KS	1250	LANDFILL-2	Lawrence Energy Center	Y	N	N	Y	N	Y	N	N	N	N	N	N
KS	1252	-999	Tecumseh Energy Center	Y	N	N	N	Y	N	N	N	N	N	N	N
KS	1252	LANDFILL-1	Tecumseh Energy Center	Y	N	N	N	N	N	N	N	N	N	N	N
KS	1295	LANDFILL-1	Quindaro	Y	N	N	Y	N	N	N	N	N	N	N	N
KS	6064	LANDFILL-1	Nearman Creek	Y	N	N	Y	N	N	N	N	N	N	N	N
KS	6064	LANDFILL-2	Nearman Creek	Y	N	N	N	N	N	N	N	N	N	N	N
KS	6068	LANDFILL-1	Jeffrey Energy Center	Y	N	N	N	N	N	N	N	N	N	N	N
KS	6068	LANDFILL-2	Jeffrey Energy Center	Y	N	N	N	N	Y	N	N	N	N	N	N
KY	1363	LANDFILL-1	Cane Run	Y	N	N	N	N	N	N	N	N	N	N	N
KY	1364	LANDFILL-1	Mill Creek	Y	N	N	N	N	N	N	N	N	N	N	N
KY	1364	LANDFILL-2	Mill Creek	Y	N	N	Y	N	Y	N	N	N	N	N	N
KY	1364	LANDFILL-3	Mill Creek	Y	N	N	N	N	N	N	N	N	N	N	N
KY	1379	LANDFILL-1	Shawnee	Y	N	N	N	N	N	N	N	N	N	N	N
KY	1379	LANDFILL-2	Shawnee	Y	N	N	N	Y	N	N	N	N	N	N	N
KY	1382	LANDFILL	HMP&L Station Two Henderson	Y	N	N	N	Y	N	N	N	N	N	N	N
KY	1384	LANDFILL	Cooper Station.	Y	N	N	N	Y	N	N	N	N	N	N	N
KY	6018	LANDFILL-1	East Bend Station	Y	N	N	Y	N	Y	N	N	N	N	N	N
KY	6041	LANDFILL-1	H L Spurlock Station	Y	N	Y	N	N	N	N	N	N	N	N	N
KY	6639	LANDFILL-1	R D Green	Y	N	N	N	N	Y	N	N	N	N	N	N
KY	6823	LANDFILL-1	D B Wilson	Y	N	N	N	N	N	N	N	N	N	N	N
KY	6823	LANDFILL-2	D B Wilson	Y	N	N	N	N	N	N	N	N	N	N	N
LA	51	LANDFILL-1	Dolet Hills	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
LA	1393	LANDFILL-1	RS Nelson	Y	N	N	Y	N	Y	N	N	N	Y	Y	N

Exhibit H-2
List of Engineering Controls for Each of the 310 Landfills (Existing Units)

State	Plant Code	Landfill ID	Plant Name	Groundwater Monitoring	Liner				Leachate Collection System	Cap			Dust Controls	Run-on/Run-off	Post Closure Monitoring
					Synthetic	Clay	Yes	Unknown		Synthetic	Clay	Soil			
LA	1393	LANDFILL-2	RS Nelson	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
LA	6055	LANDFILL-1	Big Cajun 2	Y	N	Y	N	N	N	N	N	N	Y	Y	N
MA	1619	LANDFILL-1	Brayton Point	N	N	N	Y	N	Y	N	N	N	N	N	N
MD	1570	LANDFILL-1	R. Paul Smith Power Station	N	N	N	Y	N	Y	N	N	N	N	N	N
MD	1571	LANDFILL-1	Chalk Point LLC	N	N	N	Y	N	Y	N	N	N	N	N	N
MD	1571	LANDFILL-2	Chalk Point LLC	N	N	N	Y	N	Y	N	N	N	N	N	N
MD	1572	LANDFILL-2	Dickerson	N	N	N	Y	N	Y	N	N	N	N	N	N
MD	1573	LANDFILL-1	Morgantown Generating Plant	N	N	N	Y	N	Y	N	N	N	N	N	N
MD	1573	LANDFILL-2	Morgantown Generating Plant	N	N	N	Y	N	Y	N	N	N	N	N	N
MI	1702	LANDFILL-1	D.E. Karn	Y	N	N	N	Y	Y	N	N	N	Y	Y	N
MI	1710	LANDFILL-1	Consumers Energy - J.H. Campbell	Y	Y	N	N	N	Y	N	N	N	Y	Y	N
MI	1710	LANDFILL-2	Consumers Energy - J.H. Campbell	Y	Y	N	N	N	Y	N	N	N	Y	Y	N
MI	1710	LANDFILL-3	Consumers Energy - J.H. Campbell	Y	Y	N	N	N	Y	N	N	N	Y	Y	N
MI	1710	LANDFILL-4	Consumers Energy - J.H. Campbell	Y	Y	N	N	N	Y	N	N	N	Y	Y	N
MI	1720	LANDFILL-1	J.C. Weadock	Y	N	N	N	Y	Y	N	N	N	Y	Y	N
MI	1745	LANDFILL-1	Trenton Channel Power Plant	Y	N	N	N	N	N	N	N	N	Y	Y	N
MI	1769	LANDFILL-1	Presque Isle	Y	N	N	Y	N	Y	N	N	N	Y	N	N
MI	1830	LANDFILL-1	James De Young	Y	N	N	N	N	Y	N	N	N	Y	Y	N
MI	6034	LANDFILL-1	Belle River	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
MN	1893	LANDFILL-1	Boswell Energy Center	Y	N	N	N	N	Y	N	N	N	Y	Y	N
MN	1893	LANDFILL-2	Boswell Energy Center	Y	N	N	N	N	Y	N	N	N	Y	Y	N
MN	1915	LANDFILL-1	Allen S King	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
MN	1943	LANDFILL-1	Hoot Lake	Y	N	N	N	N	N	N	N	N	Y	Y	N
MN	1943	LANDFILL-2	Hoot Lake	Y	N	N	N	N	N	N	N	N	Y	Y	N
MN	1943	LANDFILL-3	Hoot Lake	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
MN	6090	LANDFILL-1	Sherburne County	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
MN	10075	LANDFILL-1	Taconite Harbor Energy Center	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
MN	10075	LANDFILL-2	Taconite Harbor Energy Center	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
MN	10075	LANDFILL-3	Taconite Harbor Energy Center	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
MO	2079	LANDFILL	Hawthorn	Y	N	N	N	Y	N	N	N	N	Y	Y	N
MO	2080	LANDFILL-1	Montrose	Y	N	N	Y	N	N	N	N	N	Y	Y	N
MO	2094	LANDFILL-1	Sibley	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
MO	2161	LANDFILL-1	James River Power Station	Y	Y	N	N	N	Y	N	N	N	Y	Y	N
MO	2167	LANDFILL-1	New Madrid	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
MO	2168	LANDFILL-1	Thomas Hill	Y	N	N	N	N	N	N	N	N	Y	Y	N
MO	6065	LANDFILL-1	Iatan	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
MO	6195	LANDFILL-1	Southwest Power Station	Y	N	N	N	N	Y	N	N	N	Y	Y	N
MS	2049	LANDFILL-1	Jack Watson	Y	N	N	Y	N	Y	N	N	N	N	Y	N
MS	6061	LANDFILL-1	South Mississippi El Pwr Assn	Y	N	N	N	Y	N	N	N	N	N	Y	N
MS	6061	LANDFILL-2	South Mississippi El Pwr Assn	Y	N	N	N	Y	N	N	N	N	N	Y	N
MS	6061	LANDFILL-3	South Mississippi El Pwr Assn	Y	N	N	Y	N	Y	N	N	N	N	Y	N
MS	6073	LANDFILL-1	Victor J. Daniel Jr	Y	N	N	Y	N	N	N	N	N	N	Y	N
MS	6073	LANDFILL-2	Victor J. Daniel Jr	Y	N	N	Y	N	N	N	N	N	N	Y	N
MS	55076	LANDFILL-1	Red Hills Generating Facility	Y	N	N	Y	N	Y	N	N	N	N	Y	N
MT	6089	LANDFILL-1	Lewis & Clark	Y	N	N	N	N	N	N	N	N	N	Y	N
MT	10784	LANDFILL-1	Colstrip Energy LP	Y	N	N	N	N	N	N	N	N	N	Y	N
NC	2712	LANDFILL-1	Roxboro Steam Electric Plant	Y	N	N	N	N	Y	N	N	N	N	N	N
NC	2718	LANDFILL-1	G G Allen	Y	N	N	Y	N	Y	N	N	N	N	N	N
NC	2727	LANDFILL-1	Marshall	Y	Y	N	N	N	Y	N	N	N	N	N	N
NC	8042	LANDFILL-1	Belews Creek Steam Station	Y	Y	N	N	N	Y	N	N	N	N	N	N
NC	8042	LANDFILL-2	Belews Creek Steam Station	Y	Y	N	N	N	Y	N	N	N	N	N	N

Exhibit H-2
List of Engineering Controls for Each of the 310 Landfills (Existing Units)

State	Plant Code	Landfill ID	Plant Name	Groundwater Monitoring	Liner				Leachate Collection System	Cap			Dust Controls	Run-on/Run-off	Post Closure Monitoring
					Synthetic	Clay	Yes	Unknown		Synthetic	Clay	Soil			
ND	2790	LANDFILL-1	R.M. Heskett Station	Y	N	N	Y	N	Y	N	N	N	Y	N	N
ND	2817	LANDFILL-1	Leland Olds	Y	N	N	N	N	N	N	N	N	Y	N	N
ND	2817	LANDFILL-2	Leland Olds	Y	N	N	Y	N	N	N	N	N	Y	N	N
ND	2823	LANDFILL-1	Milton R. Young Station	Y	N	N	Y	N	Y	N	N	N	Y	N	N
ND	2823	LANDFILL-2	Milton R. Young Station	Y	N	N	N	N	Y	N	N	N	Y	N	N
ND	2824	LANDFILL-1	Stanton	Y	N	Y	N	N	Y	N	N	N	Y	N	N
ND	2824	LANDFILL-2	Stanton	Y	N	Y	N	N	N	N	N	N	Y	N	N
ND	6030	LANDFILL-1	Coal Creek	Y	N	N	Y	N	N	N	N	N	Y	N	N
ND	6030	LANDFILL-2	Coal Creek	Y	N	N	Y	N	N	N	N	N	Y	N	N
ND	6030	LANDFILL-3	Coal Creek	Y	N	N	Y	N	N	N	N	N	Y	N	N
ND	6469	LANDFILL-1	Antelope Valley Station	Y	N	Y	N	N	N	N	N	N	Y	N	N
ND	6469	LANDFILL-2	Antelope Valley Station	Y	N	Y	N	N	N	N	N	N	Y	N	N
ND	8222	LANDFILL-1	Coyote	Y	N	Y	N	N	N	N	N	N	Y	N	N
ND	8222	LANDFILL-2	Coyote	Y	N	N	N	N	N	N	N	N	Y	N	N
NE	59	LANDFILL-1	Platte	N	N	N	N	N	N	N	N	N	N	N	N
NE	2240	LANDFILL-1	Lon Wright	N	N	N	Y	N	Y	N	N	N	N	N	N
NE	2277	LANDFILL-1	Sheldon Station	N	N	N	Y	N	Y	N	N	N	N	N	N
NE	2291	LANDFILL-1	North Omaha	N	N	N	N	N	N	N	N	N	N	N	N
NE	6077	LANDFILL-1	Gerald Gentleman	N	N	N	Y	N	N	N	N	N	N	N	N
NE	6096	LANDFILL-1	Nebraska City	N	N	N	N	N	N	N	N	N	N	N	N
NE	6096	LANDFILL-2	Nebraska City	N	N	N	Y	N	Y	N	N	N	N	N	N
NH	2364	LANDFILL-1	Merrimack Station	N	N	N	Y	N	Y	N	N	N	N	N	N
NJ	2403	LANDFILL-1	PSEG Hudson Generating Station	N	N	N	N	N	N	N	N	N	N	N	N
NJ	2408	LANDFILL-1	PSEG Mercer Generating Station	N	N	N	N	N	N	N	N	N	N	N	N
NM	87	LANDFILL-1	Escalante	N	N	Y	N	N	N	N	N	N	N	N	N
NM	2442	LANDFILL-1	Four Corners	N	N	Four	Y	N	Y	N	N	N	N	N	N
NM	2442	LANDFILL-2	Four Corners	N	N	N	N	N	N	N	N	N	N	N	N
NV	2324	LANDFILL-1	Reid Gardner	Y	N	N	N	N	N	N	N	N	Y	Y	N
NV	8224	LANDFILL-1	North Valmy	Y	N	N	N	N	N	N	N	N	Y	Y	N
NV	56224	LANDFILL	TS Power Plant	Y	N	N	N	Y	Y	N	N	N	Y	Y	N
NY	2527	LANDFILL-1	AES Greenidge	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
NY	2535	LANDFILL-1	AES Cayuga, LLC	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
NY	2549	LANDFILL-1	CR Huntley Generating Station	Y	N	N	Y	N	N	N	N	N	Y	Y	N
NY	2554	LANDFILL-1	Dunkirk Generating Plant	Y	Y	N	N	N	Y	N	N	N	Y	Y	N
NY	6082	LANDFILL-1	AES Somerset LLC	Y	Y	N	N	N	Y	N	N	N	Y	Y	N
OH	2828	LANDFILL-1	Cardinal	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
OH	2830	LANDFILL-1	Walter C Beckjord	Y	N	Y	N	N	Y	N	N	N	Y	Y	N
OH	2832	LANDFILL-1	Miami Fort	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
OH	2836	LANDFILL	Avon Lake	Y	N	N	N	Y	Y	N	N	N	Y	Y	N
OH	2837	LANDFILL-1	Eastlake	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
OH	2840	LANDFILL-1	Conesville	Y	Y	N	N	N	Y	N	N	N	Y	Y	N
OH	2850	LANDFILL-1	J M Stuart	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
OH	2850	LANDFILL-2	J M Stuart	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
OH	2866	LANDFILL-1	W. H. Sammis	Y	Y	N	N	N	Y	N	N	N	Y	Y	N
OH	2876	LANDFILL-1	Kyger Creek	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
OH	2878	LANDFILL	Bay Shore	Y	N	N	N	Y	Y	N	N	N	Y	Y	N
OH	6019	LANDFILL-1	W H Zimmer	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
OH	8102	LANDFILL-1	General James M. Gavin	Y	Y	N	N	N	Y	N	N	N	Y	Y	N
OK	165	LANDFILL-1	GRDA	Y	N	N	Y	N	N	N	N	N	Y	Y	N
OK	2963	LANDFILL-1	Northeastern	Y	N	N	Y	N	N	N	N	N	Y	Y	N
OK	6772	LANDFILL-1	Hugo	Y	N	Y	N	N	N	N	N	N	Y	Y	N

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State	Plant Code	Landfill ID	Plant Name	Groundwater Monitoring	Liner				Leachate Collection System	Cap			Dust Controls	Run-on/Run-off	Post Closure Monitoring
					Synthetic	Clay	Yes	Unknown		Synthetic	Clay	Soil			
OR	6106	LANDFILL-1	Boardman	N	N	N	N	N	N	N	N	N	N	N	N
PA	3113	LANDFILL-1	Portland	Y	Y	N	N	N	Y	N	N	N	Y	Y	N
PA	3115	LANDFILL-1	Titus	Y	N	N	N	N	Y	N	N	N	Y	Y	N
PA	3118	LANDFILL-1	Conemaugh	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
PA	3122	LANDFILL-1	Homer City Station	Y	N	N	N	N	Y	N	N	N	Y	Y	N
PA	3122	LANDFILL-2	Homer City Station	Y	Y	N	N	N	Y	N	N	N	Y	Y	N
PA	3131	LANDFILL-1	Shawville	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
PA	3136	LANDFILL-1	Keystone	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
PA	3136	LANDFILL-2	Keystone	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
PA	3138	LANDFILL-1	New Castle Plant	Y	Y	N	N	N	Y	N	N	N	Y	Y	N
PA	3140	LANDFILL-1	PPL Brunner Island	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
PA	3149	LANDFILL-1	PPL Montour	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
PA	3178	LANDFILL-1	Armstrong Power Station	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
PA	3179	LANDFILL-1	Hatfield's Ferry Power Station	Y	N	N	N	N	Y	N	N	N	Y	Y	N
PA	3181	LANDFILL-1	Mitchell Power Station	Y	N	N	N	N	Y	N	N	N	Y	Y	N
PA	8226	LANDFILL-1	Cheswick Power Plant	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
PA	10343	LANDFILL-1	Foster Wheeler Mt Carmel Cogen	Y	N	N	N	Y	Y	N	N	N	Y	Y	N
SC	130	LANDFILL-1	Cross	Y	N	N	N	N	N	N	N	N	Y	Y	N
SC	130	LANDFILL-2	Cross	Y	N	N	N	Y	Y	N	N	N	Y	Y	N
SC	130	LANDFILL-3	Cross	Y	N	N	N	Y	Y	N	N	N	Y	Y	N
SC	130	LANDFILL-4	Cross	Y	N	N	N	Y	Y	N	N	N	Y	Y	N
SC	3287	LANDFILL-1	McMeekin	Y	N	N	N	N	N	N	N	N	Y	Y	N
SC	3295	LANDFILL-1	Urquhart	Y	N	N	N	N	N	N	N	N	Y	Y	N
SC	3297	LANDFILL-1	Wateree	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
SC	3298	LANDFILL-1	Williams	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
SC	3298	LANDFILL-2	Williams	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
SC	6249	LANDFILL	Winyah	Y	N	N	N	Y	Y	N	N	N	Y	Y	N
SC	7210	LANDFILL-1	Cope	Y	N	N	N	N	N	N	N	N	Y	Y	N
SD	6098	LANDFILL-1	Big Stone	N	N	N	N	N	N	N	N	N	N	N	N
TN	3396	LANDFILL-1	Bull Run	Y	N	N	N	N	Y	N	N	N	Y	Y	N
TN	3399	LANDFILL	Cumberland	Y	N	N	N	Y	Y	N	N	N	Y	Y	N
TN	3405	LANDFILL-1	John Sevier	Y	Y	N	N	N	Y	N	N	N	Y	Y	N
TN	3406	LANDFILL-1	Johnsonville	Y	N	N	N	N	N	N	N	N	Y	Y	N
TX	127	LANDFILL	Oklaunion	N	N	N	N	Y	N	N	N	N	N	N	N
TX	298	LANDFILL-1	Limestone	N	N	N	Y	N	Y	N	N	N	N	N	N
TX	3470	LANDFILL-1	W. A. Parish	N	N	N	Y	N	N	N	N	N	N	N	N
TX	3497	LANDFILL-1	Big Brown	N	N	Y	N	N	N	N	N	N	N	N	N
TX	6136	LANDFILL-1	Gibbons Creek Steam Electric Station	N	N	N	Y	N	Y	N	N	N	N	N	N
TX	6136	LANDFILL-2	Gibbons Creek Steam Electric Station	N	N	N	Y	N	Y	N	N	N	N	N	N
TX	6139	LANDFILL-1	Welsh	N	N	N	N	N	N	N	N	N	N	N	N
TX	6146	LANDFILL-1	Martin Lake	N	N	N	Y	N	Y	N	N	N	N	N	N
TX	6147	LANDFILL-1	Monticello	N	N	N	N	N	N	N	N	N	N	N	N
TX	6147	LANDFILL-2	Monticello	N	N	N	Y	N	N	N	N	N	N	N	N
TX	6179	LANDFILL-2	Fayette Power Project	N	N	N	Y	N	N	N	N	N	N	N	N
TX	6180	LANDFILL-1	Oak Grove	N	N	N	Y	N	N	N	N	N	N	N	N
TX	6180	LANDFILL-2	Oak Grove	N	N	N	N	N	N	N	N	N	N	N	N
TX	6180	LANDFILL-3	Oak Grove	N	N	N	N	N	N	N	N	N	N	N	N
TX	6181	LANDFILL-1	J T Deely	N	N	N	Y	N	N	N	N	N	N	N	N
TX	6181	LANDFILL-2	J T Deely	N	N	N	N	Y	N	N	N	N	N	N	N
TX	6183	LANDFILL-1	San Miguel	N	N	N	Y	N	N	N	N	N	N	N	N
TX	6193	LANDFILL-1	Harrington	N	N	N	Y	N	N	N	N	N	N	N	N

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State	Plant Code	Landfill ID	Plant Name	Groundwater Monitoring	Liner				Lechate Collection System	Cap			Dust Controls	Run-on/Run-off	Post Closure Monitoring
					Synthetic	Clay	Yes	Unknown		Synthetic	Clay	Soil			
TX	6193	LANDFILL-2	Harrington	N	N	N	Y	N	N	N	N	N	N	N	N
TX	6194	LANDFILL-4	Tolk	N	N	N	N	N	N	N	N	N	N	N	N
TX	6648	LANDFILL-1	Sadow No 4	N	N	Y	N	N	N	N	N	N	N	N	N
TX	6648	LANDFILL-2	Sadow No 4	N	N	N	N	N	N	N	N	N	N	N	N
TX	6648	LANDFILL-3	Sadow No 4	N	N	N	N	N	N	N	N	N	N	N	N
TX	6648	LANDFILL-4	Sadow No 4	N	N	N	N	N	N	N	N	N	N	N	N
TX	7030	LANDFILL-1	Twin Oaks Power One	N	N	N	Y	N	Y	N	N	N	N	N	N
TX	7097	LANDFILL-1	J K Spruce	N	N	N	Y	N	N	N	N	N	N	N	N
TX	7902	LANDFILL-1	Pirkey	N	Y	N	N	N	N	N	N	N	N	N	N
UT	3644	LANDFILL-1	Carbon Plant	Y	N	N	N	N	N	N	N	N	Y	Y	N
UT	6165	LANDFILL-1	Hunter Plant	Y	N	N	N	N	N	N	N	N	Y	Y	N
UT	7790	LANDFILL-1	Bonanza Power Plant	Y	N	N	N	N	N	N	N	N	Y	Y	N
UT	7790	LANDFILL-2	Bonanza Power Plant	Y	N	N	N	N	N	N	N	N	Y	Y	N
UT	8069	LANDFILL-1	Huntington Plant	Y	N	N	N	N	N	N	N	N	Y	Y	N
UT	8069	LANDFILL-2	Huntington Plant	Y	N	N	N	N	N	N	N	N	Y	Y	N
UT	50951	LANDFILL-1	Sunnyside Cogen Associates	Y	N	N	N	N	N	N	N	N	Y	Y	N
VA	3775	LANDFILL-1	Clinch River	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
VA	3776	LANDFILL-1	Glen Lyn	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
VA	3803	LANDFILL-1	Chesapeake Energy Center	Y	N	N	Y	N	N	N	N	N	Y	Y	N
VA	3809	LANDFILL-1	Yorktown	Y	N	Y	N	N	Y	N	N	N	Y	Y	N
VA	7213	LANDFILL-1	Clover	Y	Y	N	N	N	Y	N	N	N	Y	Y	N
WA	3845	LANDFILL-1	TransAlta Centralia Generation	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
WI	3982	LANDFILL-1	Bay Front	N	N	N	Y	N	Y	N	N	N	N	N	N
WI	4041	LANDFILL-1	South Oak Creek	N	N	N	Y	N	Y	N	N	N	N	N	N
WI	4042	LANDFILL-1	Valley	N	N	N	Y	N	Y	N	N	N	N	N	N
WI	4042	LANDFILL-2	Valley	N	N	N	Y	N	Y	N	N	N	N	N	N
WI	4050	LANDFILL-1	Edgewater	N	N	N	Y	N	N	N	N	N	N	N	N
WI	4078	LANDFILL-1	Weston	N	N	N	Y	N	Y	N	N	N	N	N	N
WI	4140	LANDFILL-1	Alma	N	N	N	N	Y	N	N	N	N	N	N	N
WI	4143	LANDFILL-1	Genoa	N	N	N	N	Y	N	N	N	N	N	N	N
WI	4271	LANDFILL-1	John P. Madgett	N	N	N	N	Y	N	N	N	N	N	N	N
WI	6170	LANDFILL-1	Pleasant Prairie	N	N	N	Y	N	Y	N	N	N	N	N	N
WI	8023	LANDFILL-1	Columbia	N	N	N	Y	N	Y	N	N	N	N	N	N
WV	3935	LANDFILL-1	John E. Amos	N	N	N	Y	N	Y	N	N	N	N	N	N
WV	3935	LANDFILL-2	John E. Amos	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
WV	3938	LANDFILL	Philip Sporn	N	N	N	N	Y	N	N	N	N	N	N	N
WV	3942	LANDFILL-1	Albright Power Station	N	N	N	N	N	Y	N	N	N	N	N	N
WV	3943	LANDFILL-1	Fort Martin Power Station	N	N	N	N	N	Y	N	N	N	N	N	N
WV	3943	LANDFILL-2	Fort Martin Power Station	Y	N	N	Y	N	Y	N	N	N	Y	Y	N
WV	3944	LANDFILL-1	Harrison Power Station	N	N	Y	N	N	Y	N	N	N	N	N	N
WV	3945	LANDFILL-1	Rivesville Power Station	N	N	N	N	N	Y	N	N	N	N	N	N
WV	3946	LANDFILL-1	Willow Island	N	N	N	Y	N	Y	N	N	N	N	N	N
WV	3954	LANDFILL-1	Mt. Storm	N	N	N	N	N	Y	N	N	N	N	N	N
WV	3954	LANDFILL-2	Mt. Storm	Y	Y	N	N	N	Y	N	N	N	Y	Y	N
WV	3954	LANDFILL-3	Mt. Storm	N	N	Y	N	N	Y	N	N	N	N	N	N
WV	6004	LANDFILL-1	Pleasants Power Station	N	N	N	Y	N	Y	N	N	N	N	N	N
WV	6264	LANDFILL-1	Mountaineer	N	Y	N	N	N	Y	N	N	N	N	N	N
WV	10151	LANDFILL-1	Grant Town Power Plant	Y	N	N	N	N	N	N	N	N	Y	Y	N
WV	10151	LANDFILL-2	Grant Town Power Plant	Y	N	N	N	N	N	N	N	N	Y	Y	N
WV	10151	LANDFILL-3	Grant Town Power Plant	Y	N	N	N	N	N	N	N	N	Y	Y	N
WY	4158	LANDFILL-1	Dave Johnston Plant	Y	N	N	N	N	N	N	N	N	Y	Y	N

Exhibit H-2															
List of Engineering Controls for Each of the 310 Landfills (Existing Units)															
State	Plant Code	Landfill ID	Plant Name	Groundwater Monitoring	Liner				Lechate Collection System	Cap			Dust Controls	Run-on/ Run-off	Post Closure Monitoring
					Synthetic	Clay	Yes	Unknown		Synthetic	Clay	Soil			
WY	4162	LANDFILL	Naughton Plant	Y	N	N	N	Y	N	N	N	N	Y	Y	N
WY	6101	LANDFILL	Wyodak Plant	Y	N	N	N	Y	N	N	N	N	Y	Y	N
WY	6204	LANDFILL-1	Laramie River Station	Y	N	N	N	N	Y	N	N	N	Y	Y	N
WY	8066	LANDFILL-1	Jim Bridger Plant Units 1-4	Y	N	N	N	N	N	N	N	N	Y	Y	N

Exhibit H-3 List of Engineering Controls for Each of the 735 Surface Impoundments (New Unit Construction)															
State	Plant Code	Unit Name	Plant Name	Groundwater Monitoring	Liner					Leachate Collection System	Cap				Current PCM
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
AK	6288	SPD-1	Healy	N	N	N	N	N	N	N	N	N	N	N	N
AL	3	Barry Ash Pond	Barry	N	N	N	N	N	N	N	N	N	N	N	N
AL	7	Ash Pond (NID #1428)	Gadsden	N	N	N	N	N	Y	N	N	N	N	N	N
AL	8	Ash Pond (NID #1198) Rattlesnake Dam	Gorgas	N	N	N	N	N	N	N	N	N	N	N	N
AL	8	Gypsum Storage Facility	Gorgas	N	Y	N	N	N	N	N	N	N	N	N	N
AL	10	Ash Pond	Greene County	N	N	N	N	N	N	N	N	N	N	N	N
AL	26	Ash Pond Dam	E. C. Gaston	N	N	N	N	N	N	N	N	N	N	N	N
AL	47	Ash Pond 4	Colbert	N	N	N	N	N	Y	N	N	N	N	N	N
AL	47	Disposal Area 5	Colbert	N	N	N	N	N	Y	N	N	N	N	N	N
AL	47	Disposal Area 5 Basin	Colbert	N	N	N	N	N	Y	N	N	N	N	N	N
AL	50	Ash Pond	Widows Creek	N	N	N	N	N	Y	N	N	N	N	N	N
AL	50	Bottom Ash Stack	Widows Creek	N	N	N	N	N	N	N	N	N	N	N	N
AL	50	Dredge Cell	Widows Creek	N	N	N	N	N	N	N	N	N	N	N	N
AL	50	Gypsum Stack (Wet Stacking Area)	Widows Creek	N	N	N	N	N	Y	N	N	N	N	N	N
AL	50	Gypsum Stack Pond 1	Widows Creek	N	N	N	N	N	N	N	N	N	N	N	N
AL	50	Gypsum Stack Pond 2A	Widows Creek	N	N	N	N	N	N	N	N	N	N	N	N
AL	50	Gypsum Stack Pond 2B	Widows Creek	N	N	N	N	N	N	N	N	N	N	N	N
AL	50	Gypsum Stack Pond 3	Widows Creek	N	N	N	N	N	N	N	N	N	N	N	N
AL	50	Gypsum Stack Stilling Pond	Widows Creek	N	N	N	N	N	N	N	N	N	N	N	N
AL	50	Pump Pond	Widows Creek	N	N	N	N	N	N	N	N	N	N	N	N
AL	50	Red Water Pond	Widows Creek	N	N	N	N	N	N	N	N	N	N	N	N
AL	50	Upper/Lower Stilling Pond	Widows Creek	N	N	N	N	N	N	N	N	N	N	N	N
AL	56	#1 Bottom Ash Pond	Charles R. Lowman	N	N	N	N	N	N	N	N	N	N	N	N
AL	56	Process Waste Pond	Charles R. Lowman	N	N	N	N	N	N	N	N	N	N	N	N
AL	56	Scrubber Waste Pond	Charles R. Lowman	N	N	N	N	N	N	N	N	N	N	N	N
AL	56	Units 2-3 Pond	Charles R. Lowman	N	N	N	N	N	N	N	N	N	N	N	N
AL	6002	Ash Pond (NID #1101)	James H. Miller Jr.	N	N	N	N	N	Y	N	N	N	N	N	N
AR	6138	Primary Bottom Ash Pond	Flint Creek	N	N	N	N	N	Y	N	N	N	N	N	N
AR	6138	Secondary Bottom Ash Pond	Flint Creek	N	N	N	N	N	Y	N	N	N	N	N	N
AZ	113	Bottom Ash Pond	Cholla	N	N	N	N	N	N	N	Y	N	N	N	Y
AZ	113	Fly Ash Pond	Cholla	N	N	N	N	N	N	N	Y	N	N	N	Y
AZ	160	Ash Pond 1	Apache Station	N	Y	N	N	N	N	N	Y	N	N	N	Y
AZ	160	Ash Pond 2	Apache Station	N	Y	N	N	N	N	N	Y	N	N	N	Y
AZ	160	Ash Pond 3	Apache Station	N	Y	N	N	N	N	N	Y	N	N	N	Y
AZ	160	Ash Pond 4	Apache Station	N	Y	N	N	N	N	N	Y	N	N	N	Y
AZ	160	Cooling Tower Blowdown Pond	Apache Station	N	N	N	N	N	Y	N	Y	N	N	N	Y
AZ	160	Evaporation 1	Apache Station	N	Y	N	N	N	N	N	Y	N	N	N	Y
AZ	160	Evaporation Pond	Apache Station	N	Y	N	N	N	N	N	Y	N	N	N	Y
AZ	160	Low Volume Wastewater Pond	Apache Station	N	N	N	N	N	Y	N	Y	N	N	N	Y
AZ	160	Scrubber Sludge Pond 1	Apache Station	N	Y	N	N	N	N	N	Y	N	N	N	Y
AZ	160	Scrubber Sludge Pond 2	Apache Station	N	Y	N	N	N	N	N	Y	N	N	N	Y
AZ	6177	Evaporation Pond/Dam	Coronado Generating Station	N	N	N	N	N	N	N	Y	N	N	N	Y
CO	465	Ash Pump Pond	Arapahoe	Y	N	N	N	N	Y	Y	Y	N	N	N	Y
CO	465	South Ash Pond	Arapahoe	Y	N	N	N	N	Y	Y	Y	N	N	N	Y
CO	469	Center Ash Pond	Cherokee	Y	N	N	N	N	Y	Y	Y	N	N	N	Y
CO	469	East Ash Pond	Cherokee	Y	N	N	N	N	Y	Y	Y	N	N	N	Y
CO	469	East Polishing Pond	Cherokee	Y	N	N	N	N	Y	Y	Y	N	N	N	Y
CO	469	Emergency Spill Pond	Cherokee	Y	N	N	N	N	Y	Y	Y	N	N	N	Y
CO	469	West Ash Pond	Cherokee	Y	N	N	N	N	Y	Y	Y	N	N	N	Y
CO	469	West Polishing Pond	Cherokee	Y	N	N	N	N	Y	Y	Y	N	N	N	Y
CO	470	Ash Disposal Facility (ADF) Stormwater Retention Pond	Comanche	Y	N	N	N	N	Y	Y	Y	N	N	N	Y
CO	470	Ash Pond #1	Comanche	Y	N	N	N	N	Y	Y	Y	N	N	N	Y
CO	470	Ash Pond #2	Comanche	Y	N	N	N	N	Y	Y	Y	N	N	N	Y
CO	470	Ash Pond #3	Comanche	Y	N	N	N	N	Y	Y	Y	N	N	N	Y
CO	470	Polishing Pond (#4)	Comanche	Y	N	N	N	N	Y	Y	Y	N	N	N	Y
CO	477	East Ash Settling Pond	Valmont	Y	N	N	N	N	Y	Y	Y	N	N	N	Y

Exhibit H-3 List of Engineering Controls for Each of the 735 Surface Impoundments (New Unit Construction)															
State	Plant Code	Unit Name	Plant Name	Groundwater Monitoring	Liner					Leachate Collection System	Cap				Current PCM
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
CO	477	West Ash Settling Pond	Valmont	Y	N	N	N	N	Y	Y	Y	N	N	N	Y
CO	492	SPD-1	Martin Drake	Y	N	N	N	N	N	Y	Y	N	N	N	Y
CO	492	SPD-5	Martin Drake	Y	N	N	N	N	N	Y	Y	N	N	N	Y
CO	492	SPD-6	Martin Drake	Y	N	N	N	N	N	Y	Y	N	N	N	Y
CO	492	SPD-7	Martin Drake	Y	N	N	N	N	N	Y	Y	N	N	N	Y
CO	525	Ash Disposal Facility (ADF) Contact Storm Water Pond	Hayden	Y	N	N	N	N	Y	Y	Y	N	N	N	Y
CO	525	Common Wet Ash Settling Basin	Hayden	Y	N	N	N	N	Y	Y	Y	N	N	N	Y
CO	525	Fly Ash Decant Basin	Hayden	Y	N	N	N	N	Y	Y	Y	N	N	N	Y
CO	525	Intermediate Quality Pond	Hayden	Y	N	N	N	N	Y	Y	Y	N	N	N	Y
CO	527	Coal/Ash Settling Basin	Nucla	Y	N	N	N	N	Y	Y	Y	N	N	N	Y
CO	6248	Ash Disposal Facility (ADF)	Pawnee	Y	N	N	N	N	Y	Y	Y	N	N	N	Y
CO	6248	Evaporative Pond B	Pawnee	Y	N	N	N	N	Y	Y	Y	N	N	N	Y
CO	6248	Evaporative Pond C	Pawnee	Y	N	N	N	N	Y	Y	Y	N	N	N	Y
CO	6248	Intermediate Quality (IQ) Water Pond	Pawnee	Y	N	N	N	N	Y	Y	Y	N	N	N	Y
CO	6248	New Bottom Ash Water Recovery Pond	Pawnee	Y	N	N	N	N	Y	Y	Y	N	N	N	Y
CO	6761	North Bottom Ash Transfer Pond	Rawhide	Y	N	N	N	N	Y	Y	Y	N	N	N	Y
CO	6761	South Bottom Ash Transfer Pond	Rawhide	Y	N	N	N	N	Y	Y	Y	N	N	N	Y
DE	594	Sedimentation Pond	Indian River Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
DE	10030	Waste Water Pond	NRG Energy Center Dover	N	N	N	N	N	Y	N	N	N	N	N	N
FL	641	SPD-1	Crist	Y	N	N	N	N	N	N	N	N	N	N	N
FL	641	SPD-5	Crist	Y	N	N	N	N	N	N	N	N	N	N	N
FL	641	SPD-6	Crist	Y	Y	N	N	N	N	N	N	N	N	N	N
FL	642	SPD-1	Scholz	Y	N	N	N	N	N	N	N	N	N	N	N
FL	642	SPD-2	Scholz	Y	N	N	N	N	N	N	N	N	N	N	N
FL	642	SPD-3	Scholz	Y	N	N	N	N	N	N	N	N	N	N	N
FL	643	Ash Pond	Lansing Smith	Y	N	N	N	N	N	N	N	N	N	N	N
FL	645	Longterm Flyash Pond	Big Bend	Y	N	N	N	N	Y	N	N	N	N	N	N
FL	645	North Bottom Ash	Big Bend	Y	Y	N	N	N	N	N	N	N	N	N	N
FL	645	North Economizer Ash Pond	Big Bend	Y	Y	N	N	N	N	N	N	N	N	N	N
FL	645	North Recycle Pond	Big Bend	Y	N	N	N	N	Y	N	N	N	N	N	N
FL	645	Settling Pond	Big Bend	Y	N	N	N	N	Y	N	N	N	N	N	N
FL	645	South Bottom Ash Pond	Big Bend	Y	Y	N	N	N	N	N	N	N	N	N	N
FL	645	South Economizer Ash Pond	Big Bend	Y	Y	N	N	N	N	N	N	N	N	N	N
FL	645	South Recycle Pond	Big Bend	Y	N	N	N	N	Y	N	N	N	N	N	N
FL	663	SPD-1	Deerhaven Generating Station	Y	N	N	N	N	N	N	N	N	N	N	N
GA	703	Ash Pond	Bowen	N	N	Y	N	N	N	N	N	N	N	N	N
GA	708	Ash Pond 1	Hammond	N	N	N	N	N	N	N	N	N	N	N	N
GA	708	Ash Pond 2	Hammond	N	N	N	N	N	N	N	N	N	N	N	N
GA	708	Ash Pond 4	Hammond	N	N	N	N	N	N	N	N	N	N	N	N
GA	709	Ash Pond B	Harlee Branch	N	N	N	N	N	N	N	N	N	N	N	N
GA	709	Ash Pond C	Harlee Branch	N	N	N	N	N	N	N	N	N	N	N	N
GA	709	Ash Pond D	Harlee Branch	N	N	N	N	N	N	N	N	N	N	N	N
GA	709	Ash Pond E	Harlee Branch	N	N	N	N	N	N	N	N	N	N	N	N
GA	710	Ash Pond 2	Jack McDonough	N	N	N	N	N	N	N	N	N	N	N	N
GA	710	Ash Pond 3	Jack McDonough	N	N	N	N	N	N	N	N	N	N	N	N
GA	710	Ash Pond 4	Jack McDonough	N	N	N	N	N	N	N	N	N	N	N	N
GA	727	Ash Pond 1	Mitchell	N	N	N	N	N	N	N	N	N	N	N	N
GA	727	Ash Pond 2	Mitchell	N	N	N	N	N	N	N	N	N	N	N	N
GA	727	Ash Pond A	Mitchell	N	N	N	N	N	N	N	N	N	N	N	N
GA	728	Ash Pond 1	Yates	N	N	N	N	N	N	N	N	N	N	N	N
GA	728	Ash Pond 2	Yates	N	N	N	N	N	N	N	N	N	N	N	N
GA	728	Ash Pond 3	Yates	N	N	N	N	N	N	N	N	N	N	N	N
GA	728	B' Pond	Yates	N	N	N	N	N	N	N	N	N	N	N	N
GA	728	Gypsum Solid Waste Facility	Yates	N	Y	N	N	N	N	N	N	N	N	N	N
GA	733	Ash Pond	Kraft	N	N	N	N	N	Y	N	N	N	N	N	N
GA	753	SPD-1	Crisp Plant	N	N	N	N	N	Y	N	N	N	N	N	N

Exhibit H-3 List of Engineering Controls for Each of the 735 Surface Impoundments (New Unit Construction)															
State	Plant Code	Unit Name	Plant Name	Groundwater Monitoring	Liner					Leachate Collection System	Cap				Current PCM
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
GA	6052	Ash Pond	Wansley	N	N	N	N	N	N	N	N	N	N	N	N
GA	6124	Ash Pond	McIntosh	N	N	N	N	N	Y	N	N	N	N	N	N
GA	6257	Ash Pond	Scherer	N	N	N	N	N	N	N	N	N	N	N	N
GA	6257	Settlement-Recycle Pond	Scherer	N	N	N	N	N	N	N	N	N	N	N	N
IA	1046	Ash Channel	Dubuque	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1047	Lower Ash Pond	Lansing	N	N	N	N	N	N	N	N	N	N	N	N
IA	1047	Main Ash Pond	Lansing	N	N	N	N	N	N	N	N	N	N	N	N
IA	1048	Emergency Ash Primary Settling Pond	ML Kapp	N	N	N	N	N	N	N	N	N	N	N	N
IA	1048	Emergency Ash Secondary Settling Pond	ML Kapp	N	N	N	N	N	N	N	N	N	N	N	N
IA	1048	Main Ash Primary Settling Pond	ML Kapp	N	N	N	N	N	N	N	N	N	N	N	N
IA	1048	Main Ash Secondary Settling Pond	ML Kapp	N	N	N	N	N	N	N	N	N	N	N	N
IA	1073	Ash Pond #1	Prairie Creek	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1073	Ash Pond #10	Prairie Creek	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1073	Ash Pond #2	Prairie Creek	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1073	Ash Pond #3	Prairie Creek	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1073	Ash Pond #4	Prairie Creek	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1073	Ash Pond #5	Prairie Creek	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1073	Ash Pond #6	Prairie Creek	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1073	Ash Pond #7	Prairie Creek	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1073	Ash Pond #8 - Plant Drains	Prairie Creek	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1073	Ash Pond #9 - Dumper Building	Prairie Creek	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1077	Main Ash Settling Pond	Sutherland	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1077	Unit 1 & 2 Initial Settling Pond	Sutherland	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1077	Unit 3 Initial Settling Pond	Sutherland	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1081	North Ash Pond	Riverside	N	N	N	N	N	N	N	N	N	N	N	N
IA	1081	South Ash Pond	Riverside	N	N	N	N	N	N	N	N	N	N	N	N
IA	1082	North Surface Impoundment	Walter Scott Jr. Energy Center	N	N	N	N	N	N	N	N	N	N	N	N
IA	1082	South Surface Impoundment	Walter Scott Jr. Energy Center	N	N	N	N	N	N	N	N	N	N	N	N
IA	1091	Surface Impoundment 1	George Neal North	N	N	N	N	N	N	N	N	N	N	N	N
IA	1091	Surface Impoundment 2	George Neal North	N	N	N	N	N	N	N	N	N	N	N	N
IA	1091	Surface Impoundment 3	George Neal North	N	N	N	N	N	N	N	N	N	N	N	N
IA	1104	Economizer Ash Pond	Burlington	N	N	N	N	N	N	N	N	N	N	N	N
IA	1104	Lower Ash Pond	Burlington	N	N	N	N	N	N	N	N	N	N	N	N
IA	1104	Main Ash Pond	Burlington	N	N	N	N	N	N	N	N	N	N	N	N
IA	1104	Upper Ash Pond	Burlington	N	N	N	N	N	N	N	N	N	N	N	N
IA	1122	SPD-1	Ames Electric Services Power Plant	N	N	N	N	N	Y	N	N	N	N	N	N
IA	6254	Main Ash Pond	Ottumwa	N	N	N	N	N	N	N	N	N	N	N	N
IA	6664	Bottom Ash Pond	Louisa	N	N	Y	N	N	N	N	N	N	N	N	N
IA	6664	Louisa Surface Impoundment	Louisa	N	N	Y	N	N	N	N	N	N	N	N	N
IL	856	Ash Pond	ED Edwards	N	N	N	N	N	N	N	N	N	N	N	N
IL	856	Pond 2 - Ash Pond Settling	ED Edwards	N	N	N	N	N	N	N	N	N	N	N	N
IL	856	Pond 3 - Clarification Pond	ED Edwards	N	N	N	N	N	N	N	N	N	N	N	N
IL	861	Gypsum Management Facility Recycle Pond	Coffeen	N	Y	N	N	N	N	N	N	N	N	N	N
IL	874	SPD-1	Joliet 9	N	N	N	N	N	N	N	N	N	N	N	N
IL	874	SPD-2	Joliet 9	N	N	N	N	N	N	N	N	N	N	N	N
IL	876	Slag Field	Kincaid Generation LLC	N	N	N	N	N	N	N	N	N	N	N	N
IL	879	SPD-1	Powerton	N	N	N	N	N	N	N	N	N	N	N	N
IL	879	SPD-2	Powerton	N	N	N	N	N	N	N	N	N	N	N	N
IL	879	SPD-3	Powerton	N	N	N	N	N	N	N	N	N	N	N	N
IL	883	SPD-1	Waukegan	N	Y	N	N	N	N	N	N	N	N	N	N
IL	883	SPD-2	Waukegan	N	Y	N	N	N	N	N	N	N	N	N	N
IL	887	Ash Pond	Joppa Steam	N	N	N	N	N	N	N	N	N	N	N	N
IL	889	Ash Pond System	Baldwin Energy Complex	N	N	N	N	N	Y	N	N	N	N	N	N
IL	891	East Ash Pond	Havana	N	Y	N	N	N	N	N	N	N	N	N	N
IL	891	North Ash Pond System	Havana	N	N	N	N	N	Y	N	N	N	N	N	N
IL	892	Ash Pond System (2 cells)	Hennepin Power Station	N	N	N	N	N	Y	N	N	N	N	N	N
IL	898	East Ash Pond (2 cells)	Wood River	N	Y	N	N	N	N	N	N	N	N	N	N

Exhibit H-3 List of Engineering Controls for Each of the 735 Surface Impoundments (New Unit Construction)															
State	Plant Code	Unit Name	Plant Name	Groundwater Monitoring	Liner					Leachate Collection System	Cap				Current PCM
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
IL	898	West Ash Pond (2 cells) Cells 2E and 3	Wood River	N	N	Y	N	N	N	N	N	N	N	N	N
IL	963	Dallman Ash Pond	Dallman	N	N	N	N	N	N	N	N	N	N	N	N
IL	976	Fly Ash Disposal Pond	Marion Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
IL	976	Pond 1	Marion Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
IL	976	Pond 2	Marion Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
IL	976	Pond 3	Marion Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
IL	976	Pond 3A	Marion Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
IL	976	Pond 4	Marion Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
IL	976	Pond A-1	Marion Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
IL	976	Pond S-1	Marion Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
IL	976	Pond S-2	Marion Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
IL	976	Pond S-3	Marion Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
IL	976	Pond S-6	Marion Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
IL	976	South Fly Ash Pond	Marion Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
IL	6016	Recycle Pond	Duck Creek	N	N	Y	N	N	N	N	N	N	N	N	N
IL	6017	Primary Ash Pond	Newton	N	N	N	N	N	N	N	N	N	N	N	N
IL	6017	Secondary Ash Pond	Newton	N	N	N	N	N	N	N	N	N	N	N	N
IL	6238	SPD-1	Pearl Station	N	N	N	N	N	N	N	N	N	N	N	N
IN	983	South Fly Ash Runoff Pond Site 16	Clifty Creek	N	N	N	N	N	N	N	N	N	N	N	N
IN	983	West Bottom Ash Pond Site 16 (Regn 5)	Clifty Creek	N	N	N	N	N	N	N	N	N	N	N	N
IN	988	Boiler Slag Pond (U-4)	Tanners Creek	N	N	N	N	N	Y	N	N	N	N	N	N
IN	988	Bottom Ash Complex	Tanners Creek	N	N	N	N	N	N	N	N	N	N	N	N
IN	988	Fly Ash Pond	Tanners Creek	N	Y	N	N	N	N	N	N	N	N	N	N
IN		Fly Ash Pond - Clear Pond and Original (Lower Pond) Dike	Tanners Creek	N	Y	N	N	N	N	N	N	N	N	N	N
IN	988	Fly Ash Pond - Upper Pond	Tanners Creek	N	N	N	N	N	N	N	N	N	N	N	N
IN	990	Pond 1	Harding Street	N	N	N	N	N	N	N	N	N	N	N	N
IN	990	Pond 2	Harding Street	N	N	N	N	N	N	N	N	N	N	N	N
IN	990	Pond 3	Harding Street	N	N	N	N	N	N	N	N	N	N	N	N
IN	990	Pond 4	Harding Street	N	N	N	N	N	N	N	N	N	N	N	N
IN	990	Ponds 2A/2B	Harding Street	N	N	N	N	N	N	N	N	N	N	N	N
IN	991	A Pond	Eagle Valley	N	N	N	N	N	N	N	N	N	N	N	N
IN	991	B Pond	Eagle Valley	N	N	N	N	N	N	N	N	N	N	N	N
IN	991	C Pond	Eagle Valley	N	N	N	N	N	N	N	N	N	N	N	N
IN	991	D Pond	Eagle Valley	N	N	N	N	N	N	N	N	N	N	N	N
IN	994	Pond A - Active	AES Petersburg	N	N	N	N	N	N	N	N	N	N	N	N
IN	994	Pond A - Discharge	AES Petersburg	N	N	N	N	N	N	N	N	N	N	N	N
IN	995	Bottom Ash Pond	Bailly	N	N	N	N	N	Y	N	N	N	N	N	N
IN	995	Primary 1	Bailly	N	N	N	N	N	Y	N	N	N	N	N	N
IN	995	Primary 2	Bailly	N	N	N	N	N	Y	N	N	N	N	N	N
IN	995	Secondary 1	Bailly	N	N	N	N	N	Y	N	N	N	N	N	N
IN	995	Secondary 2	Bailly	N	N	N	N	N	Y	N	N	N	N	N	N
IN	997	Bottom Ash Area	Michigan City	N	N	N	N	N	Y	N	N	N	N	N	N
IN	997	Final Settling Pond	Michigan City	N	N	N	N	N	Y	N	N	N	N	N	N
IN	997	Primary 1	Michigan City	N	N	N	N	N	Y	N	N	N	N	N	N
IN	997	Primary 2	Michigan City	N	N	N	N	N	Y	N	N	N	N	N	N
IN	997	Secondary 1	Michigan City	N	N	N	N	N	Y	N	N	N	N	N	N
IN	997	Secondary 2	Michigan City	N	N	N	N	N	Y	N	N	N	N	N	N
IN	1001	Ash Disposal Area #1	Cayuga	N	N	N	N	N	N	N	N	N	N	N	N
IN	1001	Lined Ash Disposal Pond - Cell #1	Cayuga	N	Y	N	N	N	N	N	N	N	N	N	N
IN	1001	Primary Ash Settling Basin	Cayuga	N	N	N	N	N	N	N	N	N	N	N	N
IN	1001	Secondary Ash Settling Basin	Cayuga	N	N	N	N	N	N	N	N	N	N	N	N
IN	1004	Primary Ash Pond	Edwardsport	N	N	N	N	N	N	N	N	N	N	N	N
IN	1004	Secondary Ash Pond	Edwardsport	N	N	N	N	N	N	N	N	N	N	N	N
IN	1008	Ash Pond A	R. Gallagher	N	N	N	N	N	N	N	N	N	N	N	N
IN	1008	Secondary Ash Pond	R. Gallagher	N	N	N	N	N	N	N	N	N	N	N	N
IN	1010	Primary Ash Pond Cell A	Wabash River	N	N	N	N	N	N	N	N	N	N	N	N

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State	Plant Code	Unit Name	Plant Name	Groundwater Monitoring	Liner					Leachate Collection System	Cap				Current PCM
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
IN	1010	Primary Ash Pond Cell B	Wabash River	N	N	N	N	N	N	N	N	N	N	N	N
IN	1010	Secondary Ash Pond	Wabash River	N	N	N	N	N	N	N	N	N	N	N	N
IN	1010	South Ash Pond	Wabash River	N	Y	N	N	N	N	N	N	N	N	N	N
IN	1012	East Pond	F. B. Culley	N	N	N	N	N	N	N	N	N	N	N	N
IN	1040	SPD-5	Whitewater Valley	N	N	N	N	N	N	N	N	N	N	N	N
IN	1043	Bottom Ash Pond	Frank E. Ratts	N	N	N	N	N	N	N	N	N	N	N	N
IN	1043	Fly Ash Pond 1	Frank E. Ratts	N	N	N	N	N	N	N	N	N	N	N	N
IN	1043	Fly Ash Pond 2	Frank E. Ratts	N	N	N	N	N	N	N	N	N	N	N	N
IN	1043	Fly Ash Pond 3	Frank E. Ratts	N	N	N	N	N	N	N	N	N	N	N	N
IN	1043	Pond 1	Frank E. Ratts	N	N	N	N	N	N	N	N	N	N	N	N
IN	1043	Pond 2	Frank E. Ratts	N	N	N	N	N	Y	N	N	N	N	N	N
IN	1043	Pond 3	Frank E. Ratts	N	N	N	N	N	Y	N	N	N	N	N	N
IN	1043	Pond 4	Frank E. Ratts	N	N	N	N	N	Y	N	N	N	N	N	N
IN	6085	FGD Landfill Stormwater Runoff Pond	R.M. Schahfer	N	N	N	N	N	N	N	N	N	N	N	N
IN	6085	Gypsum Storage (Units 14&15)A	R.M. Schahfer	N	N	N	N	N	N	N	N	N	N	N	N
IN	6085	Gypsum Storage (Units 14&15)B	R.M. Schahfer	N	N	N	N	N	N	N	N	N	N	N	N
IN	6085	Material Storage Runoff Basin	R.M. Schahfer	N	N	N	N	N	N	N	N	N	N	N	N
IN	6085	Metal Cleaning Waste Basin	R.M. Schahfer	N	N	N	N	N	N	N	N	N	N	N	N
IN	6085	Recycle Basin	R.M. Schahfer	N	N	N	N	N	N	N	N	N	N	N	N
IN	6113	East Pond #1	Gibson	N	N	N	N	N	N	N	N	N	N	N	N
IN	6113	East Pond #2	Gibson	N	N	N	N	N	N	N	N	N	N	N	N
IN	6113	East Pond #3	Gibson	N	N	N	N	N	N	N	N	N	N	N	N
IN	6113	East Settling Basin	Gibson	N	N	N	N	N	N	N	N	N	N	N	N
IN	6113	North Ash Pond	Gibson	N	N	N	N	N	N	N	N	N	N	N	N
IN	6113	North Settling Basin	Gibson	N	N	N	N	N	N	N	N	N	N	N	N
IN	6137	Lower Ash Pond	A. B. Brown Generating Station	N	N	N	N	N	N	N	N	N	N	N	N
IN	6137	Upper Ash Pond	A. B. Brown Generating Station	N	N	N	N	N	N	N	N	N	N	N	N
IN	6166	Bottom Ash Complex	Rockport	N	N	N	N	N	N	N	N	N	N	N	N
IN	6705	EPRI 9	Warrick Power Plant	N	N	N	N	N	Y	N	N	N	N	N	N
KS	1239	Industrial Landfill-East and West Ponds	Riverton	Y	N	N	N	N	N	N	N	N	N	N	N
KS	1241	Bottom Ash Settling Pond	La Cygne	Y	N	Y	N	N	N	N	N	N	N	N	N
KS	1241	Scrubber Sludge Ponds	La Cygne	Y	N	Y	N	N	N	N	N	N	N	N	N
KS	1250	Area 1	Lawrence Energy Center	Y	N	N	N	N	N	N	N	N	N	N	N
KS	1250	Area 2	Lawrence Energy Center	Y	N	N	N	N	N	N	N	N	N	N	N
KS	1250	Area 3	Lawrence Energy Center	Y	N	Y	N	N	N	N	N	N	N	N	N
KS	1250	Area 4	Lawrence Energy Center	Y	N	N	N	N	N	N	N	N	N	N	N
KS	1252	Area 1	Tecumseh Energy Center	Y	N	N	N	N	N	N	N	N	N	N	N
KS	1252	Area 2	Tecumseh Energy Center	Y	N	N	N	N	N	N	N	N	N	N	N
KS	6064	N/A	Nearman Creek	Y	N	Y	N	N	N	N	N	N	N	N	N
KS	6068	Bottom Ash Lake Dam	Jeffrey Energy Center	Y	N	N	N	N	N	N	N	N	N	N	N
KS	6068	Bottom Ash Pond Dam	Jeffrey Energy Center	Y	N	N	N	N	N	N	N	N	N	N	N
KS	6068	Bottom Ash Settling Pond	Jeffrey Energy Center	Y	N	N	N	N	Y	N	N	N	N	N	N
KY	1353	Bottom Ash Complex	Big Sandy	N	N	N	N	N	N	N	N	N	N	N	N
KY	1353	Fly Ash	Big Sandy	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1353	Horseford Run Dam	Big Sandy	N	N	Y	N	N	N	N	N	N	N	N	N
KY	1355	Ash Pond	E.W. Brown	N	Y	N	N	N	N	N	N	N	N	N	N
KY	1355	Auxiliary Pond	E.W. Brown	N	Y	N	N	N	N	N	N	N	N	N	N
KY	1356	Ash Treatment Basin #1	Ghent	N	N	N	N	N	N	N	N	N	N	N	N
KY	1356	Ash Treatment Basin #2	Ghent	N	N	N	N	N	N	N	N	N	N	N	N
KY	1356	Gypsum Stack Surge/Reclaim Pond	Ghent	N	N	Y	N	N	N	N	N	N	N	N	N
KY	1356	Gypsum Stacking Facility	Ghent	N	N	N	N	N	N	N	N	N	N	N	N
KY	1356	Secondary Ash Treatment Basin	Ghent	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1357	Ash Pond Number 2	Green River	N	N	N	N	N	N	N	N	N	N	N	N
KY	1357	Finishing Pond Number 3	Green River	N	N	N	N	N	N	N	N	N	N	N	N
KY	1357	Former Ash Pond	Green River	N	N	N	N	N	N	N	N	N	N	N	N
KY	1357	Main Ash Pond	Green River	N	N	N	N	N	N	N	N	N	N	N	N
KY	1357	Scrubber Pond	Green River	N	N	N	N	N	N	N	N	N	N	N	N

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					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
KY	1361	Ash Pond	Tyrone	N	N	N	N	N	N	N	N	N	N	N	N
KY	1361	Secondary Ash Pond	Tyrone	N	N	N	N	N	N	N	N	N	N	N	N
KY	1363	Basin Pond	Cane Run	N	N	N	N	N	N	N	N	N	N	N	N
KY	1363	Clearwell Pond	Cane Run	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1363	Dead Storage Pond	Cane Run	N	N	N	N	N	N	N	N	N	N	N	N
KY	1363	Emergency Pond	Cane Run	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1363	Main Ash Pond/E-Pond	Cane Run	N	N	N	N	N	N	N	N	N	N	N	N
KY	1364	Ash Pond	Mill Creek	N	N	N	N	N	N	N	N	N	N	N	N
KY	1364	Clearwell Pond	Mill Creek	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1364	Construction Run Off Pond	Mill Creek	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1364	Dead Storage Pond	Mill Creek	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1364	Emergency Pond	Mill Creek	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1374	SPD-1	Elmer Smith	N	N	N	N	N	N	N	N	N	N	N	N
KY	1374	SPD-2	Elmer Smith	N	N	N	N	N	N	N	N	N	N	N	N
KY	1374	SPD-4	Elmer Smith	N	Y	N	N	N	N	N	N	N	N	N	N
KY	1374	SPD-6	Elmer Smith	N	N	N	N	N	N	N	N	N	N	N	N
KY	1378	Fly Ash Extension Area Pond	Paradise	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1378	Scrubber Sludge Complex	Paradise	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1379	Ash Pond	Shawnee	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1379	Consolidated Waste Dry Stack	Shawnee	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1381	Active Ash Pond A	Kenneth C Coleman	N	N	N	N	N	N	N	N	N	N	N	N
KY	1381	Inactive Ash Pond C	Kenneth C Coleman	N	N	N	N	N	N	N	N	N	N	N	N
KY	1381	New Ash Pond	Kenneth C Coleman	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1382	Ash Pond No. 0855	HMP&L Station Two Henderson	N	N	N	N	N	N	N	N	N	N	N	N
KY	1382	Green Ash Pond	HMP&L Station Two Henderson	N	N	N	N	N	N	N	N	N	N	N	N
KY	1385	Dale Ash Pond #2	Dale Station	N	N	N	N	N	N	N	N	N	N	N	N
KY	1385	Dale Ash Pond #3	Dale Station	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1385	Dale Ash Pond #4	Dale Station	N	N	N	N	N	N	N	N	N	N	N	N
KY	6018	East Bend Station Unit 1	East Bend Station	N	N	N	N	N	N	N	N	N	N	N	N
KY	6018	FGD Pond East	East Bend Station	N	N	N	N	N	Y	N	N	N	N	N	N
KY	6018	FGD Pond West	East Bend Station	N	N	N	N	N	Y	N	N	N	N	N	N
KY	6041	Spurlock Ash Pond	H L Spurlock Station	N	N	Y	N	N	N	N	N	N	N	N	N
KY	6071	Coal Combustion Waste Pond	Trimble Co.	N	N	Y	N	N	N	N	N	N	N	N	N
KY	6639	Ash Pond Dam #0980	R D Green	N	N	N	N	N	N	N	N	N	N	N	N
LA	51	Ash Basin No. 1	Dolet Hills	Y	Y	N	N	N	N	N	N	Y	N	N	Y
LA	51	Ash Basin No. 2	Dolet Hills	Y	Y	N	N	N	N	N	N	Y	N	N	Y
LA	51	Auxiliary Surge Pond	Dolet Hills	Y	Y	N	N	N	N	N	N	Y	N	N	Y
LA	51	Landfill Storm Water/Leachate	Dolet Hills	Y	Y	N	N	N	N	N	N	Y	N	N	Y
LA	51	Secondary Basin	Dolet Hills	Y	Y	N	N	N	N	N	N	Y	N	N	Y
LA	51	Surge Pond No. 1	Dolet Hills	Y	Y	N	N	N	N	N	N	Y	N	N	Y
LA	51	Surge Pond No. 2	Dolet Hills	Y	Y	N	N	N	N	N	N	Y	N	N	Y
LA	6055	Bottom Ash Unit	Big Cajun 2	Y	Y	N	N	N	N	N	N	Y	N	N	Y
LA	6055	Fly Ash Unit	Big Cajun 2	Y	Y	N	N	N	N	N	N	Y	N	N	Y
LA	6055	Water Treatment Unit	Big Cajun 2	Y	Y	N	N	N	N	N	N	Y	N	N	Y
LA	6190	Bottom Ash Pond	Rodemacher	Y	Y	N	N	N	N	N	N	Y	N	N	Y
LA	6190	Fly Ash Pond	Rodemacher	Y	Y	N	N	N	N	N	N	Y	N	N	Y
LA	6190	Leachate Pond	Rodemacher	Y	Y	N	N	N	N	N	N	Y	N	N	Y
MA	1619	SPD-4	Brayton Point	N	Y	N	N	N	N	N	N	N	N	N	N
MA	1619	SPD-5	Brayton Point	N	Y	N	N	N	N	N	N	N	N	N	N
MA	1619	SPD-6	Brayton Point	N	Y	N	N	N	N	N	N	N	N	N	N
MD	602	SPD-5	Brandon Shores	N	Y	N	N	N	N	N	N	N	N	N	N
MD	602	SPD-6	Brandon Shores	N	Y	N	N	N	N	N	N	N	N	N	N
MD	1570	Ash Pond #3	R. Paul Smith Power Station	N	N	N	N	N	N	N	N	N	N	N	N
MD	1570	Ash Pond #4	R. Paul Smith Power Station	N	Y	N	N	N	N	N	N	N	N	N	N
MI	1702	DE Karn 1 and 2 Solid Waste Disposal Area	D.E. Karn	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
MI	1702	Pond A	D.E. Karn	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
MI	1720	East 7 & 8 Ponds	J.C. Weadock	Y	N	Y	N	N	N	Y	Y	N	N	N	Y

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					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
MI	1720	J.C. Weadock Fly Ash Dam	J.C. Weadock	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
MI	1720	Weadock Landfill Embankment	J.C. Weadock	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
MI	1720	West A - E Ponds	J.C. Weadock	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
MI	1723	Pond 1	J.R Whiting	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
MI	1723	Pond 2	J.R Whiting	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
MI	1723	Pond 6	J.R Whiting	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
MI	1723	Ponds 3-5	J.R Whiting	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
MI	1731	Pond	Harbor Beach Power Plant	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
MI	1733	Bottom Ash Basin	Monroe Power Plant	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
MI	1733	Fly Ash Basin	Monroe Power Plant	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
MI	1740	SPD-1	River Rouge	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
MI	1743	Pond	St Clair Power Plant	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
MI	1745	Pond	Trenton Channel Power Plant	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
MI	1825	SPD-1	J B Sims	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
MI	1825	SPD-2	J B Sims	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
MI	1830	SPD-1	James De Young	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
MI	1832	Unit 1	Erickson Station	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
MI	6034	Pond	Belle River	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
MN	1891	Cell E	Laskin Energy Center	N	Y	N	N	N	N	N	N	N	N	N	N
MN	1893	Complex: Pond 3, 4, and Bottom Ash Pond	Boswell Energy Center	N	N	Y	N	N	N	N	N	N	N	N	N
MN	1893	Wastewater Treatment Plant Pond	Boswell Energy Center	N	N	Y	N	N	N	N	N	N	N	N	N
MN	1904	Settling Ponds 1-4	Black Dog	N	N	N	N	N	N	N	N	N	N	N	N
MN	6090	Bottom Ash Pond	Sherburne County	N	N	Y	N	N	N	N	N	N	N	N	N
MN	6090	Pond 3 N	Sherburne County	N	Y	N	N	N	N	N	N	N	N	N	N
MN	6090	Pond No. 1	Sherburne County	N	N	Y	N	N	N	N	N	N	N	N	N
MN	6090	Pond No. 2	Sherburne County	N	N	Y	N	N	N	N	N	N	N	N	N
MN	6090	Recycle Basin	Sherburne County	N	N	N	N	N	Y	N	N	N	N	N	N
MN	6090	Unit No. 3 Dry Ash Landfill Basin	Sherburne County	N	N	N	N	N	Y	N	N	N	N	N	N
MO	2076	Ash Impoundment	Asbury	N	N	N	N	N	Y	N	N	N	N	N	N
MO	2076	Lower Pond	Asbury	N	N	N	N	N	N	N	N	N	N	N	N
MO	2076	Upper Pond	Asbury	N	N	N	N	N	N	N	N	N	N	N	N
MO	2079	Scrubber Waste Settling Pond	Hawthorn	N	N	N	N	N	Y	N	N	N	N	N	N
MO	2080	Ash Settling Pond	Montrose	N	N	N	N	N	Y	N	N	N	N	N	N
MO	2080	North Ash Pond	Montrose	N	N	N	N	N	Y	N	N	N	N	N	N
MO	2080	South Ash Pond	Montrose	N	N	N	N	N	Y	N	N	N	N	N	N
MO	2094	Fly Ash Settling Pond	Sibley	N	N	Y	N	N	N	N	N	N	N	N	N
MO	2094	Slag Settling Pond	Sibley	N	N	N	N	N	N	N	N	N	N	N	N
MO	2098	Settling Pond	Lake Road	N	N	N	N	N	Y	N	N	N	N	N	N
MO	2103	Bottom Ash Pond	Labadie	N	N	N	N	N	N	N	N	N	N	N	N
MO	2103	Fly Ash Pond	Labadie	N	Y	N	N	N	N	N	N	N	N	N	N
MO	2104	Bottom Ash Pond (3)	Meramec	N	N	N	N	N	N	N	N	N	N	N	N
MO	2104	New Fly Ash Pond	Meramec	N	Y	N	N	N	N	N	N	N	N	N	N
MO	2104	Old Fly Ash Pond	Meramec	N	Y	N	N	N	N	N	N	N	N	N	N
MO	2107	Bottom Ash Pond	Sioux	N	N	N	N	N	N	N	N	N	N	N	N
MO	2107	Fly Ash Pond	Sioux	N	Y	N	N	N	N	N	N	N	N	N	N
MO	2123	SPD-1	Columbia	N	N	N	N	N	N	N	N	N	N	N	N
MO	2132	Bottom Ash Pond	Independence Power & Light - Blue Valley Station	N	N	N	N	N	N	N	N	N	N	N	N
MO	2132	North Fly Ash Pond	Independence Power & Light - Blue Valley Station	N	N	N	N	N	N	N	N	N	N	N	N
MO	2161	Pond	James River Power Station	N	N	N	N	N	Y	N	N	N	N	N	N
MO	2167	Ash Pond 1	New Madrid	N	N	N	N	N	N	N	N	N	N	N	N
MO	2167	Ash Pond 2	New Madrid	N	Y	N	N	N	N	N	N	N	N	N	N
MO	2167	Slag Pond 1	New Madrid	N	N	N	N	N	N	N	N	N	N	N	N
MO	2167	Slag Pond 2	New Madrid	N	N	N	N	N	N	N	N	N	N	N	N
MO	2168	Ash - 2 Landfill	Thomas Hill	N	N	N	N	N	Y	N	N	N	N	N	N
MO	2168	Ash - 3 Landfill	Thomas Hill	N	N	N	N	N	Y	N	N	N	N	N	N

Exhibit H-3 List of Engineering Controls for Each of the 735 Surface Impoundments (New Unit Construction)															
State	Plant Code	Unit Name	Plant Name	Groundwater Monitoring	Liner					Leachate Collection System	Cap				Current PCM
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
MO	2168	Ash Pond Cell 1 - Upper	Thomas Hill	N	N	N	N	N	Y	N	N	N	N	N	N
MO	2168	Ash Pond Cell 2 - Middle	Thomas Hill	N	N	N	N	N	N	N	N	N	N	N	N
MO	2168	Ash Pond Cell 3 - Lowest	Thomas Hill	N	N	N	N	N	Y	N	N	N	N	N	N
MO	2168	Ash Pond Slag Dewatering	Thomas Hill	N	N	N	N	N	N	N	N	N	N	N	N
MO	2169	SPD-2	Chamois	N	N	N	N	N	N	N	N	N	N	N	N
MO	2171	SPD-1	Missouri City	N	N	N	N	N	Y	N	N	N	N	N	N
MO	6155	Ash Pond	Rush Island	N	N	N	N	N	N	N	N	N	N	N	N
MO	6195	SPD-1	Southwest Power Station	N	N	Y	N	N	N	N	N	N	N	N	N
MO	6195	SPD-2	Southwest Power Station	N	N	Y	N	N	N	N	N	N	N	N	N
MO	6768	Bottom Ash Pond	Sikeston Power Station	N	N	Y	N	N	N	N	N	N	N	N	N
MO	6768	Fly Ash Pond	Sikeston Power Station	N	N	Y	N	N	N	N	N	N	N	N	N
MS	2049	Ash Pond	Jack Watson	N	N	N	N	N	N	N	N	N	N	N	N
MS	6061	SPD-4	R D Morrow	N	N	N	N	N	Y	N	N	N	N	N	N
MS	6061	SPD-5	R D Morrow	N	N	N	N	N	Y	N	N	N	N	N	N
MS	6073	EPRI 7	Victor J. Daniel Jr	N	N	N	N	N	Y	N	N	N	N	N	N
MS	55076	SPD-1	Red Hills Generating Facility	N	N	N	N	N	Y	N	N	N	N	N	N
MT	2187	SPD-1	J E Corette Plant	N	N	N	N	N	Y	N	N	N	N	N	N
MT	2187	SPD-2	J E Corette Plant	N	N	N	N	N	Y	N	N	N	N	N	N
MT	6076	Units 1 & 2 A Pond	Colstrip	N	N	N	N	N	N	N	N	N	N	N	N
MT	6076	Units 1 & 2 B Fly Ash Pond	Colstrip	N	N	N	N	N	Y	N	N	N	N	N	N
MT	6076	Units 1 & 2 Bottom Ash Pond	Colstrip	N	Y	N	N	N	N	N	N	N	N	N	N
MT	6076	Units 1 & 2 Stage Two Evaporation Ponds (STEP)	Colstrip	N	Y	N	N	N	N	N	N	N	N	N	N
MT	6076	Units 3 & 4 Bottom Ash Pond	Colstrip	N	N	N	N	N	Y	N	N	N	N	N	N
MT	6076	Units 3 & 4 Effluent Holding Pond (EHP)	Colstrip	N	N	N	N	N	N	N	N	N	N	N	N
MT	6089	SPD-1	Lewis & Clark	N	N	Y	N	N	N	N	N	N	N	N	N
MT	6089	SPD-2	Lewis & Clark	N	N	Y	N	N	N	N	N	N	N	N	N
MT	6089	SPD-3	Lewis & Clark	N	N	Y	N	N	N	N	N	N	N	N	N
MT	6089	SPD-4	Lewis & Clark	N	N	Y	N	N	N	N	N	N	N	N	N
MT	6089	SPD-5	Lewis & Clark	N	Y	N	N	N	N	N	N	N	N	N	N
NC	2706	1964 Pond	Asheville Steam Electric Plant	N	Y	N	N	N	N	Y	N	N	N	Y	N
NC	2706	1982 Pond	Asheville Steam Electric Plant	N	Y	N	N	N	N	Y	N	N	N	Y	N
NC	2708	1978 Ash Pond	Cape Fear Steam Electric Plant	N	Y	N	N	N	N	Y	N	N	N	Y	N
NC	2708	1985 Ash Pond	Cape Fear Steam Electric Plant	N	Y	N	N	N	N	Y	N	N	N	Y	N
NC	2709	1980 Pond	H.F. Lee Plant	N	Y	N	N	N	N	Y	N	N	N	Y	N
NC	2709	Active Ash Pond	H.F. Lee Plant	N	Y	N	N	N	N	Y	N	N	N	Y	N
NC	2712	Ash Pond	Roxboro Steam Electric Plant	N	Y	N	N	N	N	Y	N	N	N	Y	N
NC	2712	FGD Flush Pond	Roxboro Steam Electric Plant	N	Y	N	N	N	N	Y	N	N	N	Y	N
NC	2712	FGD Settling Pond	Roxboro Steam Electric Plant	N	Y	N	N	N	N	Y	N	N	N	Y	N
NC	2712	West Ash Pond Dam & Dikes 1, 2,,& 4	Roxboro Steam Electric Plant	N	Y	N	N	N	N	Y	N	N	N	Y	N
NC	2713	1971 Pond	L.V. Sutton Electric Plant	N	Y	N	N	N	N	Y	N	N	N	Y	N
NC	2713	1984 Pond	L.V. Sutton Electric Plant	N	Y	N	N	N	N	Y	N	N	N	Y	N
NC	2718	Active Ash Basin	G G Allen	N	Y	N	N	N	N	Y	N	N	N	Y	N
NC	2718	East Dike - Active Ash Basin	G G Allen	N	Y	N	N	N	N	Y	N	N	N	Y	N
NC	2718	North Dike - Active Ash Basin	G G Allen	N	Y	N	N	N	N	Y	N	N	N	Y	N
NC	2720	Additional Primary Cell Basin	Buck	N	Y	N	N	N	N	Y	N	N	N	Y	N
NC	2720	Old Primary Cell	Buck	N	Y	N	N	N	N	Y	N	N	N	Y	N
NC	2720	Secondary Pond	Buck	N	Y	N	N	N	N	Y	N	N	N	Y	N
NC	2721	Active Ash Pond	Cliffside	N	Y	N	N	N	N	Y	N	N	N	Y	N
NC	2727	Active Ash Pond	Marshall	N	Y	N	N	N	N	Y	N	N	N	Y	N
NC	2732	Primary Ash Disposal Pond	Riverbend	N	Y	N	N	N	N	Y	N	N	N	Y	N
NC	2732	Secondary Pond	Riverbend	N	Y	N	N	N	N	Y	N	N	N	Y	N
NC	6250	1982 Pond	Mayo Electric Generating Facility	N	Y	N	N	N	N	Y	N	N	N	Y	N
NC	8042	Active Ash Pond	Belews Creek Steam Station	N	Y	N	N	N	N	Y	N	N	N	Y	N
ND	2817	Ash Pond #1	Leland Olds	Y	N	Y	N	N	N	Y	N	Y	N	N	Y
ND	2817	Ash Pond #2	Leland Olds	Y	N	Y	N	N	N	Y	N	Y	N	N	Y
ND	2817	Ash Pond #3	Leland Olds	Y	N	Y	N	N	N	Y	N	Y	N	N	Y

Exhibit H-3 List of Engineering Controls for Each of the 735 Surface Impoundments (New Unit Construction)															
State	Plant Code	Unit Name	Plant Name	Groundwater Monitoring	Liner					Leachate Collection System	Cap				Current PCM
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
ND	2823	30 Year Ponds (Cell 2)	Milton R. Young Station	Y	N	Y	N	N	N	Y	N	Y	N	N	Y
ND	2823	Cell 1	Milton R. Young Station	Y	N	Y	N	N	N	Y	N	Y	N	N	Y
ND	2823	Horseshoe Pit Evaporation Pond	Milton R. Young Station	Y	N	Y	N	N	N	Y	N	Y	N	N	Y
ND	2823	Unit 1 Alternative Bottom Ash Pond	Milton R. Young Station	Y	N	Y	N	N	N	Y	N	Y	N	N	Y
ND	2824	Middle Bottom Ash Pond/Retention Cell	Stanton	Y	N	Y	N	N	N	Y	N	Y	N	N	Y
ND	2824	North Bottom Ash Pond/Cell	Stanton	Y	N	Y	N	N	N	Y	N	Y	N	N	Y
ND	6030	Ash Pond 91	Coal Creek	Y	N	Y	N	N	N	Y	N	Y	N	N	Y
ND	6030	Upstream Raise/Ash Pond 92/SW Section 16	Coal Creek	Y	N	Y	N	N	N	Y	N	Y	N	N	Y
ND	8222	Ash Pond	Coyote	Y	N	Y	N	N	N	Y	N	Y	N	N	Y
ND	8222	Nelson Pond	Coyote	Y	N	Y	N	N	N	Y	N	Y	N	N	Y
ND	8222	Sluice Pond	Coyote	Y	N	Y	N	N	N	Y	N	Y	N	N	Y
NE	60	SPD-1	Whelan Energy Center	N	N	N	N	N	N	N	N	N	N	N	N
NE	2291	SPD-1	North Omaha	N	Y	N	N	N	N	N	N	N	N	N	N
NE	2291	SPD-2	North Omaha	N	Y	N	N	N	N	N	N	N	N	N	N
NE	6096	SPD-1	Nebraska City	N	N	N	N	N	N	N	N	N	N	N	N
NE	6096	SPD-2	Nebraska City	N	N	N	N	N	N	N	N	N	N	N	N
NH	2364	SPD-3	Merrimack	N	N	N	N	N	N	N	N	N	N	N	N
NH	2364	SPD-4	Merrimack	N	N	N	N	N	N	N	N	N	N	N	N
NM	87	Emergency Scrubber Pond	Escalante	N	N	N	N	N	Y	N	N	N	N	N	N
NM	87	Evaporation Pond 1a + 1b	Escalante	N	N	N	N	N	Y	N	N	N	N	N	N
NM	87	Evaporation Ponds 2-5	Escalante	N	N	N	N	N	Y	N	N	N	N	N	N
NM	87	Management Units 3 & 4 Bottom Ash	Escalante	N	N	N	N	N	Y	N	N	N	N	N	N
NM	2442	Lined Ash Impoundment	Four Corners	N	Y	N	N	N	N	N	N	N	N	N	N
NM	2442	Lined Water Impoundment	Four Corners	N	Y	N	N	N	N	N	N	N	N	N	N
NM	2442	Low Volume Waste Water Pond	Four Corners	N	N	N	N	N	Y	N	N	N	N	N	N
NM	2442	Low Volume Waste Water System Decant Cells	Four Corners	N	N	N	N	N	Y	N	N	N	N	N	N
NM	2442	Upper Retention Sump	Four Corners	N	N	N	N	N	Y	N	N	N	N	N	N
NV	2324	Pond B1	Reid Gardner	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
NV	2324	Pond B2	Reid Gardner	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
NV	2324	Pond B3	Reid Gardner	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
NV	2324	Pond E1	Reid Gardner	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
NV	2324	Pond E2	Reid Gardner	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
NV	2324	Pond F	Reid Gardner	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
NY	2527	SPD-1	AES Greenidge LLC	Y	Y	N	N	N	N	Y	N	N	N	N	Y
NY	2527	SPD-2	AES Greenidge LLC	Y	Y	N	N	N	N	Y	N	N	N	N	Y
NY	2549	North Equalization Basin	CR Huntley Generating Station	Y	Y	N	N	N	N	Y	N	N	N	N	Y
NY	2549	South Equalization Basin	CR Huntley Generating Station	Y	Y	N	N	N	N	Y	N	N	N	N	Y
NY	2549	South Settling Pond System	CR Huntley Generating Station	Y	Y	N	N	N	N	Y	N	N	N	N	Y
NY	2554	Equalization Basin	Dunkirk Generating Plant	Y	Y	N	N	N	N	Y	N	N	N	N	Y
NY	2554	Settling Pond System	Dunkirk Generating Plant	Y	Y	N	N	N	N	Y	N	N	N	N	Y
NY	6082	SPD-5	AES Somerset LLC	Y	Y	N	N	N	N	Y	N	N	N	N	Y
OH	2828	Bottom Ash Complex	Cardinal	N	N	N	N	N	N	N	N	N	N	N	N
OH	2828	Fly Ash Reservoir 2	Cardinal	N	N	N	N	N	N	N	N	N	N	N	N
OH	2830	Ash Pond B	Walter C Beckjord	N	N	N	N	N	N	N	N	N	N	N	N
OH	2830	Ash Pond C	Walter C Beckjord	N	N	N	N	N	N	N	N	N	N	N	N
OH	2832	Ash Basin A	Miami Fort	N	N	N	N	N	N	N	N	N	N	N	N
OH	2832	Ash Basin B	Miami Fort	N	N	N	N	N	N	N	N	N	N	N	N
OH	2835	SPD-1	Ashtabula	N	N	N	N	N	N	N	N	N	N	N	N
OH	2836	SPD-1	Avon Lake	N	N	N	N	N	N	N	N	N	N	N	N
OH	2836	SPD-2	Avon Lake	N	N	N	N	N	N	N	N	N	N	N	N
OH	2837	SPD-1	Eastlake	N	N	N	N	N	N	N	N	N	N	N	N
OH	2838	SPD-1	Lake Shore	N	N	N	N	N	N	N	N	N	N	N	N
OH	2840	Ash Pond Complex	Conesville	N	N	N	N	N	N	N	N	N	N	N	N
OH	2843	[blank]	Picway	N	N	N	N	N	Y	N	N	N	N	N	N
OH	2848	East Primary Settling Pond	O H Hutchings	N	N	N	N	N	N	N	N	N	N	N	N
OH	2848	Secondary Settling Pond	O H Hutchings	N	N	N	N	N	N	N	N	N	N	N	N

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State	Plant Code	Unit Name	Plant Name	Groundwater Monitoring	Liner					Leachate Collection System	Cap				Current PCM
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
OH	2848	West Primary Settling Pond	O H Hutchings	N	N	N	N	N	N	N	N	N	N	N	N
OH	2850	Ash Pond No. 10	J M Stuart	N	N	Y	N	N	N	N	N	N	N	N	N
OH	2850	Ash Pond No. 3A	J M Stuart	N	N	Y	N	N	N	N	N	N	N	N	N
OH	2866	SPD-1	W H Sammis	N	N	N	N	N	N	N	N	N	N	N	N
OH	2866	SPD-2	W H Sammis	N	N	N	N	N	N	N	N	N	N	N	N
OH	2872	Lower Fly Ash Dam	Muskingum River	N	N	N	N	N	N	N	N	N	N	N	N
OH	2872	Middle Fly Ash Pond	Muskingum River	N	N	N	N	N	N	N	N	N	N	N	N
OH	2872	Unit 1-4 Bottom Ash Pond Dam	Muskingum River	N	N	N	N	N	N	N	N	N	N	N	N
OH	2872	Upper Fly Ash Pond	Muskingum River	N	N	N	N	N	N	N	N	N	N	N	N
OH	2876	Bottom Ash Pond	Kyger Creek	N	N	N	N	N	N	N	N	N	N	N	N
OH	2876	South Fly Ash Pond	Kyger Creek	N	N	N	N	N	N	N	N	N	N	N	N
OH	2878	SPD-1	Bay Shore	N	N	N	N	N	N	N	N	N	N	N	N
OH	6019	Wastewater Pond Complex	W H Zimmer	N	N	Y	N	N	N	N	N	N	N	N	N
OH	6031	Bottom Ash Pond	Killen Station	N	N	N	N	N	Y	N	N	N	N	N	N
OH	6031	Fly Ash Pond	Killen Station	N	N	N	N	N	Y	N	N	N	N	N	N
OH	8102	Bottom Ash Pond	General James M. Gavin	N	N	N	N	N	N	N	N	N	N	N	N
OH	8102	Stingy Run Ash Disposal Pond	General James M. Gavin	N	N	N	N	N	N	N	N	N	N	N	N
OK	165	SPD-12	GRDA	N	Y	N	N	N	N	N	Y	N	N	N	N
OK	2952	SPD-1	Muskogee	N	Y	N	N	N	N	N	Y	N	N	N	N
OK	2952	SPD-3	Muskogee	N	Y	N	N	N	N	N	Y	N	N	N	N
OK	2952	SPD-6	Muskogee	N	Y	N	N	N	N	N	Y	N	N	N	N
OK	2963	Bottom Ash Pond	Northeastern	N	Y	N	N	N	N	N	Y	N	N	N	N
OK	6095	SPD-4	Sooner	N	Y	N	N	N	N	N	Y	N	N	N	N
OK	6772	North Bottom Ash Unit	Hugo	N	Y	N	N	N	N	N	Y	N	N	N	N
OK	6772	North Fly Ash	Hugo	N	Y	N	N	N	N	N	Y	N	N	N	N
OK	6772	South Bottom Ash	Hugo	N	Y	N	N	N	N	N	Y	N	N	N	N
OK	6772	South Fly Ash Unit	Hugo	N	Y	N	N	N	N	N	Y	N	N	N	N
PA	3098	SPD-1	Elrama Power Plant	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3098	SPD-2	Elrama Power Plant	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3098	SPD-4	Elrama Power Plant	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3113	SPD-1	Portland	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3113	SPD-2	Portland	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3118	SPD-3	Conemaugh	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3118	SPD-4	Conemaugh	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3118	SPD-5	Conemaugh	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3118	SPD-6	Conemaugh	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3122	Ash Disposal Site - Polishing Pond	Homer City Station	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3122	Ash Disposal Site - Treatment Pond #1	Homer City Station	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3122	Ash Disposal Site - Treatment Pond #2	Homer City Station	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3122	Ash Recycle Pond #1	Homer City Station	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3122	Ash Recycle Pond #2	Homer City Station	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3122	Ash Recycle Pond #3	Homer City Station	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3122	Ash Recycle Pond #4	Homer City Station	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3122	Coal Refuse Disposal Site - Stage I & II Pond	Homer City Station	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3122	Coal Refuse Disposal Site - Stage III & IV Pond	Homer City Station	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3122	Coal Refuse Disposal Site - Storage Pond #1	Homer City Station	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3122	Coal Refuse Disposal Site - Storage Pond #2	Homer City Station	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3131	SPD-1	Shawville	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3131	SPD-2	Shawville	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3136	SPD-10	Keystone	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3136	SPD-13	Keystone	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3136	SPD-14	Keystone	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3136	SPD-7	Keystone	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3136	SPD-8	Keystone	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3136	SPD-9	Keystone	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3138	SPD-1	New Castle Plant	Y	Y	N	N	N	N	Y	Y	N	N	N	Y

Exhibit H-3 List of Engineering Controls for Each of the 735 Surface Impoundments (New Unit Construction)															
State	Plant Code	Unit Name	Plant Name	Groundwater Monitoring	Liner					Leachate Collection System	Cap				Current PCM
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
PA	3138	SPD-2	New Castle Plant	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3140	Ash Basin No.6	PPL Brunner Island	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3140	Equalizati pond	PPL Brunner Island	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3149	Ash Basin No. 1	PPL Montour	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3152	Residual Waste Ash Basin No. 1	Sunbury Generation LP	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3179	SPD-1	Hatfields Ferry Power Station	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	3179	SPD-2	Hatfields Ferry Power Station	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	6094	East HDS (Decommissioned in 2003) (Add this unit to DB)	Bruce Mansfield	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	6094	Little Blue Run Dam	Bruce Mansfield	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	6094	North LDS Pond (N-LDS)	Bruce Mansfield	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	6094	South LDS Pond (S-LDS)	Bruce Mansfield	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	6094	West HDS Pond (W-HPDS)	Bruce Mansfield	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	8226	SPD-4	Cheswick Power Plant	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
PA	8226	SPD-5	Cheswick Power Plant	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
SC	130	Bottom Ash 1	Cross	N	N	Y	N	N	N	N	N	N	N	N	Y
SC	130	Bottom Ash 2	Cross	N	N	Y	N	N	N	N	N	N	N	N	Y
SC	130	Gypsum Pond	Cross	N	N	Y	N	N	N	N	N	N	N	N	Y
SC	3251	Pond	HB Robinson / Darlington Electric Power Plant	N	N	N	N	N	N	N	N	N	N	N	Y
SC	3264	Primary Active Ash Pond	W. S. Lee	N	N	N	N	N	N	N	N	N	N	N	Y
SC	3264	Secondary Ash Pond	W. S. Lee	N	N	N	N	N	N	N	N	N	N	N	Y
SC	3280	Ash Pond	Canadys Steam	N	N	N	N	N	N	N	N	N	N	N	Y
SC	3280	Inactive Ash Pond	Canadys Steam	N	N	N	N	N	N	N	N	N	N	N	Y
SC	3280	Polishing Pond	Canadys Steam	N	N	N	N	N	N	N	N	N	N	N	Y
SC	3295	Ash Pond	Urquhart	N	N	N	N	N	N	N	N	N	N	N	Y
SC	3295	Ash Pond 1	Urquhart	N	N	N	N	N	Y	N	N	N	N	N	Y
SC	3295	Ash Pond 2	Urquhart	N	N	N	N	N	Y	N	N	N	N	N	Y
SC	3297	Ash Pond No. 1	Waterree	N	N	N	N	N	N	N	N	N	N	N	Y
SC	3297	Ash Pond No. 2	Waterree	N	N	N	N	N	N	N	N	N	N	N	Y
SC	3319	Ash Pond A	Jefferies	N	N	N	N	N	N	N	N	N	N	N	Y
SC	3319	Ash Pond B	Jefferies	N	N	N	N	N	N	N	N	N	N	N	Y
SC	6249	Ash Pond A	Winyah	N	N	N	N	N	N	N	N	N	N	N	Y
SC	6249	Ash Pond B	Winyah	N	N	N	N	N	N	N	N	N	N	N	Y
SC	6249	South Ash Pond	Winyah	N	N	N	N	N	N	N	N	N	N	N	Y
SC	6249	Unit 2 Slurry Pond	Winyah	N	N	N	N	N	N	N	N	N	N	N	Y
SC	6249	Unit 3 & 4 Slurry Pond	Winyah	N	N	N	N	N	N	N	N	N	N	N	Y
SC	6249	West Ash Pond	Winyah	N	N	N	N	N	N	N	N	N	N	N	Y
SD	3325	SPD-1	Ben French	N	N	Y	N	N	N	N	N	N	N	N	N
SD	6098	SPD-2	Big Stone	N	N	N	N	N	N	N	N	N	N	N	N
TN	3393	East Ash Disposal	Allen Steam Plant	N	N	N	N	N	Y	N	Y	N	N	N	N
TN	3393	East Ash Stilling Pond	Allen Steam Plant	N	N	N	N	N	Y	N	Y	N	N	N	N
TN	3396	Bottom Ash Disposal Area 1	Bull Run	N	N	N	N	N	Y	N	Y	N	N	N	N
TN	3396	Dry Fly Ash Disposal Area	Bull Run	N	N	N	N	N	Y	N	Y	N	N	N	N
TN	3396	Fly Ash Pond & Stilling Basin Area 2	Bull Run	N	N	N	N	N	Y	N	Y	N	N	N	N
TN	3396	Gypsum Disposal Area 2A	Bull Run	N	N	N	N	N	Y	N	Y	N	N	N	N
TN	3399	Ash Pond	Cumberland	N	N	N	N	N	Y	N	Y	N	N	N	N
TN	3399	Dry Ash Stack	Cumberland	N	N	N	N	N	Y	N	Y	N	N	N	N
TN	3399	Gypsum Storage Area (North/South)	Cumberland	N	N	N	N	N	Y	N	Y	N	N	N	N
TN	3403	Bottom Ash Pond A	Gallatin	N	N	N	N	N	Y	N	Y	N	N	N	N
TN	3403	Fly Ash Pond E	Gallatin	N	N	N	N	N	Y	N	Y	N	N	N	N
TN	3403	Stilling Pond B, C, D	Gallatin	N	N	N	N	N	Y	N	Y	N	N	N	N
TN	3405	Bottom Ash Pond	John Sevier	N	N	N	N	N	Y	N	Y	N	N	N	N
TN	3405	Dry Ash Stack	John Sevier	N	N	N	N	N	Y	N	Y	N	N	N	N
TN	3406	Ash Disposal Area 2	Johnsonville	N	N	N	N	N	Y	N	Y	N	N	N	N
TN	3406	DuPont Road Dredge Cell	Johnsonville	N	N	N	N	N	N	N	Y	N	N	N	N
TN	3407	Main Ash Pond	Kingston	N	N	N	N	N	Y	N	Y	N	N	N	N

Exhibit H-3 List of Engineering Controls for Each of the 735 Surface Impoundments (New Unit Construction)															
State	Plant Code	Unit Name	Plant Name	Groundwater Monitoring	Liner					Lechate Collection System	Cap				Current PCM
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
TN	3407	Stilling Pond	Kingston	N	N	N	N	N	Y	N	Y	N	N	N	N
TX	127	Pond #23	Oklauion	N	N	N	N	N	Y	N	N	N	N	N	N
TX	127	Sludge Pond	Oklauion	N	N	N	N	N	Y	N	N	N	N	N	N
TX	127	Wastewater Evaporation Pond 6	Oklauion	N	N	Y	N	N	N	N	N	N	N	N	N
TX	298	Bottom Ash Cooling Pond	Limestone	N	N	N	N	N	Y	N	N	N	N	N	N
TX	298	FGD Emergency Pond E	Limestone	N	N	N	N	N	Y	N	N	N	N	N	N
TX	3470	Flue Gas Desulfurization Emergency Pond (E-Pond)	W. A. Parish	N	N	N	N	N	Y	N	N	N	N	N	N
TX		Unit 5 Bottom Ash Overflow Basin	W. A. Parish	N	N	N	N	N	Y	N	N	N	N	N	N
TX	3470	Unit 6 Bottom Ash Overflow Basin	W. A. Parish	N	N	N	N	N	Y	N	N	N	N	N	N
TX	3470	Unit 7 Bottom Ash Overflow Basin	W. A. Parish	N	N	N	N	N	Y	N	N	N	N	N	N
TX	3470	Unit 8 Bottom Ash Overflow Basin	W. A. Parish	N	N	N	N	N	Y	N	N	N	N	N	N
TX	3497	SPD-4	Big Brown	N	N	Y	N	N	N	N	N	N	N	N	N
TX	3497	SPD-5	Big Brown	N	N	N	N	N	N	N	N	N	N	N	N
TX	6136	SPD-1	Gibbons Creek	N	N	Y	N	N	N	N	N	N	N	N	N
TX	6136	SPD-2	Gibbons Creek	N	N	Y	N	N	N	N	N	N	N	N	N
TX	6136	SPD-3	Gibbons Creek	N	N	Y	N	N	N	N	N	N	N	N	N
TX	6136	SPD-5	Gibbons Creek	N	Y	N	N	N	N	N	N	N	N	N	N
TX	6139	Active Bottom Ash Storage	Welsh	N	Y	N	N	N	N	N	N	N	N	N	N
TX	6139	Primary Ash Pond	Welsh	N	N	N	N	N	N	N	N	N	N	N	N
TX	6139	Secondary Ash Pond	Welsh	N	N	N	N	N	N	N	N	N	N	N	N
TX	6146	SPD-3	Martin Lake	N	Y	N	N	N	N	N	N	N	N	N	N
TX	6146	SPD-4	Martin Lake	N	Y	N	N	N	N	N	N	N	N	N	N
TX	6146	SPD-5	Martin Lake	N	Y	N	N	N	N	N	N	N	N	N	N
TX	6146	SPD-6	Martin Lake	N	Y	N	N	N	N	N	N	N	N	N	N
TX	6147	SPD-4	Monticello	N	N	Y	N	N	N	N	N	N	N	N	N
TX	6178	Primary Ash Pond	Coletto Creek	N	N	Y	N	N	N	N	N	N	N	N	N
TX	6178	Secondary Settling Pond	Coletto Creek	N	N	Y	N	N	N	N	N	N	N	N	N
TX	6179	Management Unit 002	Fayette Power Project	N	N	Y	N	N	N	N	N	N	N	N	N
TX	6179	Management Unit 009	Fayette Power Project	N	N	Y	N	N	N	N	N	N	N	N	N
TX	6180	SPD-2	Oak Grove Power Plant	N	N	Y	N	N	N	N	N	N	N	N	N
TX	6181	SPD-1	J T Deely	N	N	N	N	N	N	N	N	N	N	N	N
TX	6181	SPD-2	J T Deely	N	N	N	N	N	N	N	N	N	N	N	N
TX	6183	SPD-3	San Miguel	N	N	Y	N	N	N	N	N	N	N	N	N
TX	6183	SPD-4	San Miguel	N	N	Y	N	N	N	N	N	N	N	N	N
TX	6648	EPRI 8	Sandow No 4	N	N	N	N	N	Y	N	N	N	N	N	N
TX	7097	SPD-1	J K Spruce	N	Y	N	N	N	N	N	N	N	N	N	N
TX	7097	SPD-2	J K Spruce	N	Y	N	N	N	N	N	N	N	N	N	N
TX	7902	Auxilliary Surge Pond	Pirkey	N	N	N	N	N	N	N	N	N	N	N	N
TX	7902	East Bottom Ash Pond	Pirkey	N	N	N	N	N	N	N	N	N	N	N	N
TX	7902	Secondary Bottom Ash Pond	Pirkey	N	N	N	N	N	N	N	N	N	N	N	N
TX	7902	West Bottom Ash Pond	Pirkey	N	N	N	N	N	N	N	N	N	N	N	N
UT	3644	SPD-1	Carbon	N	N	N	N	N	N	N	N	N	N	N	N
UT	3644	SPD-2	Carbon	N	N	N	N	N	N	N	N	N	N	N	N
UT	6481	Ash Water Recycle	Intermountain Power Project	N	Y	N	N	N	N	N	N	N	N	N	N
UT	6481	Bottom Ash Basin	Intermountain Power Project	N	Y	N	N	N	N	N	N	N	N	N	N
UT	6481	Evaporation Ponds (6 Ponds)	Intermountain Power Project	N	Y	N	N	N	N	N	N	N	N	N	N
UT	6481	Land Fill Run-Off	Intermountain Power Project	N	Y	N	N	N	N	N	N	N	N	N	N
UT	6481	Settling Basin	Intermountain Power Project	N	Y	N	N	N	N	N	N	N	N	N	N
UT	6481	Wastewater Holding Basin	Intermountain Power Project	N	Y	N	N	N	N	N	N	N	N	N	N
UT	7790	SPD-3	Bonanza	N	N	N	N	N	N	N	N	N	N	N	N
UT	7790	SPD-5	Bonanza	N	N	N	N	N	N	N	N	N	N	N	N
UT	7790	SPD-6	Bonanza	N	N	N	N	N	N	N	N	N	N	N	N
UT	8069	SPD-4	Huntington	N	Y	N	N	N	N	N	N	N	N	N	N
VA	3775	Bottom Ash Pond 1A/1B	Clinch River	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
VA	3776	Auxiliary Fly Ash Pond	Glen Lyn	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
VA	3776	Bottom Ash Pond	Glen Lyn	Y	N	Y	N	N	N	Y	Y	N	N	N	Y

Exhibit H-3 List of Engineering Controls for Each of the 735 Surface Impoundments (New Unit Construction)															
State	Plant Code	Unit Name	Plant Name	Groundwater Monitoring	Liner					Leachate Collection System	Cap				Current PCM
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
VA	3796	North Ash Pond	Bremo Bluff	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
VA	3796	West Ash Pond	Bremo Bluff	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
VA	3797	Lower (Old) Ash Pond	Chesterfield	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
VA	3797	Upper (New) Ash Pond	Chesterfield	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
VA	3803	Bottom Ash/Sedimentation Pond	Chesapeake Energy Center	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
VA	7213	SPD-2	Clover	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
VA	7213	SPD-3	Clover	Y	Y	N	N	N	N	Y	Y	N	N	N	Y
VA	10771	SPD-1	Hopewell Power Station	Y	N	Y	N	N	N	Y	Y	N	N	N	Y
WI	3982	Polishing Pond	Bay Front	N	N	N	N	N	Y	N	N	N	N	N	N
WI	3982	Surge Basin	Bay Front	N	N	N	N	N	Y	N	N	N	N	N	N
WI	4050	A Ponds (Two)	Edgewater	N	N	N	N	N	Y	N	N	N	N	N	N
WI	4050	B Pond	Edgewater	N	N	N	N	N	Y	N	N	N	N	N	N
WI	4050	C Pond	Edgewater	N	N	N	N	N	Y	N	N	N	N	N	N
WI	4050	F Pond	Edgewater	N	N	N	N	N	Y	N	N	N	N	N	N
WI	4050	Slag Pond	Edgewater	N	N	N	N	N	Y	N	N	N	N	N	N
WI	4054	Slag Pond	Nelson Dewey	N	N	N	N	N	Y	N	N	N	N	N	N
WI	4057	Final WPDES Pond	WI Power & Light Co -Rock River Generating	N	N	N	N	N	Y	N	N	N	N	N	N
WI	4057	Slag Pond	WI Power & Light Co -Rock River Generating	N	N	N	N	N	Y	N	N	N	N	N	N
WI	4057	WPDES Pond 1	WI Power & Light Co -Rock River Generating	N	N	N	N	N	Y	N	N	N	N	N	N
WI	4057	WPDES Pond 2	WI Power & Light Co -Rock River Generating	N	N	N	N	N	Y	N	N	N	N	N	N
WI	4072	SPD-1	Pulliam	N	N	N	N	N	N	N	N	N	N	N	N
WI	4078	SPD-1	Weston	N	N	N	N	N	N	N	N	N	N	N	N
WI	4078	SPD-2	Weston	N	N	Y	N	N	N	N	N	N	N	N	N
WI	4078	SPD-3	Weston	N	N	Y	N	N	N	N	N	N	N	N	N
WI	4078	SPD-4	Weston	N	N	Y	N	N	N	N	N	N	N	N	N
WI	4078	SPD-5	Weston	N	N	Y	N	N	N	N	N	N	N	N	N
WI	4078	SPD-6	Weston	N	N	Y	N	N	N	N	N	N	N	N	N
WI	8023	Polishing Pond	Columbia	N	N	N	N	N	N	N	N	N	N	N	N
WI	8023	Primary Ash Pond	Columbia	N	N	N	N	N	N	N	N	N	N	N	N
WI	8023	Secondary Ash Pond	Columbia	N	N	N	N	N	N	N	N	N	N	N	N
WV	3935	Bottom Ash Complex	John E. Amos	Y	Y	N	N	N	N	Y	N	N	N	N	Y
WV	3935	Fly Ash Pond	John E. Amos	Y	Y	N	N	N	N	Y	N	N	N	N	Y
WV	3936	Bottom Ash Complex	Kanawha River	Y	Y	N	N	N	N	Y	N	N	N	N	Y
WV	3938	Bottom Ash Pond	Philip Sporn	Y	Y	N	N	N	N	Y	N	N	N	N	Y
WV	3938	Unit 5 (Fly Ash Pond)	Philip Sporn	Y	Y	N	N	N	N	Y	N	N	N	N	Y
WV	3942	SPD-1	Albright	Y	Y	N	N	N	N	Y	N	N	N	N	Y
WV	3942	SPD-2	Albright	Y	Y	N	N	N	N	Y	N	N	N	N	Y
WV	3945	SPD-4	Rivesville	Y	Y	N	N	N	N	Y	N	N	N	N	Y
WV	3947	Boiler Slag Pond	Kammer	Y	Y	N	N	N	N	Y	N	N	N	N	Y
WV	3948	Bottom Ash Complex	Mitchell	Y	Y	N	N	N	N	Y	N	N	N	N	Y
WV	3948	Fly Ash Pond	Mitchell	Y	Y	N	N	N	N	Y	N	N	N	N	Y
WV	6004	McElroy's Run Embankment	Pleasants Power Station	Y	Y	N	N	N	N	Y	N	N	N	N	Y
WV	6264	Bottom Ash Complex	Mountaineer	Y	Y	N	N	N	N	Y	N	N	N	N	Y
WV	10151	SPD-3	Grant Town Power Plant	Y	Y	N	N	N	N	Y	N	N	N	N	Y
WV	10151	SPD-4	Grant Town Power Plant	Y	Y	N	N	N	N	Y	N	N	N	N	Y
WV	10151	SPD-7	Grant Town Power Plant	Y	Y	N	N	N	N	Y	N	N	N	N	Y
WV	10151	SPD-8	Grant Town Power Plant	Y	Y	N	N	N	N	Y	N	N	N	N	Y
WV	10151	SPD-9	Grant Town Power Plant	Y	Y	N	N	N	N	Y	N	N	N	N	Y
WY	4158	1A Clear Pond	Dave Johnston Plant	N	N	N	N	N	N	N	N	N	N	N	Y
WY	4158	1B Ash Pond	Dave Johnston Plant	N	Y	N	N	N	N	N	N	N	N	N	Y
WY	4158	1B Clear Pond	Dave Johnston Plant	N	N	N	N	N	N	N	N	N	N	N	Y
WY	4158	4 Clear Pond	Dave Johnston Plant	N	N	N	N	N	N	N	N	N	N	N	Y
WY	4158	4A Ash Pond	Dave Johnston Plant	N	Y	N	N	N	N	N	N	N	N	N	Y

Exhibit H-3 List of Engineering Controls for Each of the 735 Surface Impoundments (New Unit Construction)															
State	Plant Code	Unit Name	Plant Name	Groundwater Monitoring	Liner					Lechate Collection System	Cap				Current PCM
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
WY	4158	4B Ash Pond	Dave Johnston Plant	N	Y	N	N	N	N	N	N	N	N	N	Y
WY	4162	FGD Pond #1	Naughton Plant	N	Y	N	N	N	N	N	N	N	N	N	Y
WY	4162	FGD Pond #2	Naughton Plant	N	Y	N	N	N	N	N	N	N	N	N	Y
WY	4162	North Ash Pond	Naughton Plant	N	N	N	N	N	N	N	N	N	N	N	Y
WY	4162	South Ash Pond	Naughton Plant	N	N	N	N	N	N	N	N	N	N	N	Y
WY	6101	Wyodak	Wyodak Plant	N	N	N	N	N	N	N	N	N	N	N	Y
WY	6204	Bottom Ash Ponds 1 & 2 (BAP1 & BAP2)	Laramie River Station	N	Y	N	N	N	N	N	N	N	N	N	Y
WY	6204	Emergency Holding Pond	Laramie River Station	N	Y	N	N	N	N	N	N	N	N	N	Y
WY	8066	FGD Pond #2	Jim Bridger Plant Units 1-4	N	N	N	N	N	N	N	N	N	N	N	Y

Exhibit H-4 List of Engineering Controls for Each of the 735 Surface Impoundments (Existing Units)															
State	Plant Code	Unit Name	Plant Name	Groundwater Monitoring	Liner					Lechate Collection System	Cap				PCM
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
AK	6288	SPD-1	Healy	N	N	N	N	N	N	N	N	N	N	N	N
AL	3	Barry Ash Pond	Barry	N	N	N	N	N	N	N	N	N	N	N	N
AL	7	Ash Pond (NID #1428)	Gadsden	N	N	N	N	N	Y	N	N	N	N	N	N
AL	8	Ash Pond (NID #1198) Rattlesnake Dam	Gorgas	N	N	N	N	N	N	N	N	N	N	N	N
AL	8	Gypsum Storage Facility	Gorgas	N	Y	N	N	N	N	N	N	N	N	N	N
AL	10	Ash Pond	Greene County	N	N	N	N	N	N	N	N	N	N	N	N
AL	26	Ash Pond Dam	E. C. Gaston	N	N	N	N	N	N	N	N	N	N	N	N
AL	47	Ash Pond 4	Colbert	N	N	N	N	N	Y	N	N	N	N	N	N
AL	47	Disposal Area 5	Colbert	N	N	N	N	N	Y	N	N	N	N	N	N
AL	47	Disposal Area 5 Basin	Colbert	N	N	N	N	N	Y	N	N	N	N	N	N
AL	50	Ash Pond	Widows Creek	N	N	N	N	N	Y	N	N	N	N	N	N
AL	50	Bottom Ash Stack	Widows Creek	N	N	N	N	N	N	N	N	N	N	N	N
AL	50	Dredge Cell	Widows Creek	N	N	N	N	N	N	N	N	N	N	N	N
AL	50	Gypsum Stack (Wet Stacking Area)	Widows Creek	N	N	N	N	N	Y	N	N	N	N	N	N
AL	50	Gypsum Stack Pond 1	Widows Creek	N	N	N	N	N	N	N	N	N	N	N	N
AL	50	Gypsum Stack Pond 2A	Widows Creek	N	N	N	N	N	N	N	N	N	N	N	N
AL	50	Gypsum Stack Pond 2B	Widows Creek	N	N	N	N	N	N	N	N	N	N	N	N
AL	50	Gypsum Stack Pond 3	Widows Creek	N	N	N	N	N	N	N	N	N	N	N	N
AL	50	Gypsum Stack Stilling Pond	Widows Creek	N	N	N	N	N	N	N	N	N	N	N	N
AL	50	Pump Pond	Widows Creek	N	N	N	N	N	N	N	N	N	N	N	N
AL	50	Red Water Pond	Widows Creek	N	N	N	N	N	N	N	N	N	N	N	N
AL	50	Upper/Lower Stilling Pond	Widows Creek	N	N	N	N	N	N	N	N	N	N	N	N
AL	56	#1 Bottom Ash Pond	Charles R. Lowman	N	N	N	N	N	N	N	N	N	N	N	N
AL	56	Process Waste Pond	Charles R. Lowman	N	N	N	N	N	N	N	N	N	N	N	N
AL	56	Scrubber Waste Pond	Charles R. Lowman	N	N	N	N	N	N	N	N	N	N	N	N
AL	56	Units 2-3 Pond	Charles R. Lowman	N	N	N	N	N	N	N	N	N	N	N	N
AL	6002	Ash Pond (NID #1101)	James H. Miller Jr.	N	N	N	N	N	Y	N	N	N	N	N	N
AR	6138	Primary Bottom Ash Pond	Flint Creek	N	N	N	N	N	Y	N	N	N	N	N	N
AR	6138	Secondary Bottom Ash Pond	Flint Creek	N	N	N	N	N	Y	N	N	N	N	N	N
AZ	113	Bottom Ash Pond	Cholla	N	N	N	N	N	N	N	N	N	N	N	N
AZ	113	Fly Ash Pond	Cholla	N	N	N	N	N	N	N	N	N	N	N	N
AZ	160	Ash Pond 1	Apache Station	N	Y	N	N	N	N	N	N	N	N	N	N
AZ	160	Ash Pond 2	Apache Station	N	Y	N	N	N	N	N	N	N	N	N	N
AZ	160	Ash Pond 3	Apache Station	N	Y	N	N	N	N	N	N	N	N	N	N
AZ	160	Ash Pond 4	Apache Station	N	Y	N	N	N	N	N	N	N	N	N	N
AZ	160	Cooling Tower Blowdown Pond	Apache Station	N	N	N	N	N	Y	N	N	N	N	N	N
AZ	160	Evaporation 1	Apache Station	N	Y	N	N	N	N	N	N	N	N	N	N
AZ	160	Evaporation Pond	Apache Station	N	Y	N	N	N	N	N	N	N	N	N	N
AZ	160	Low Volume Wastewater Pond	Apache Station	N	N	N	N	N	Y	N	N	N	N	N	N
AZ	160	Scrubber Sludge Pond 1	Apache Station	N	Y	N	N	N	N	N	N	N	N	N	N
AZ	160	Scrubber Sludge Pond 2	Apache Station	N	Y	N	N	N	N	N	N	N	N	N	N
AZ	6177	Evaporation Pond/Dam	Coronado Generating Station	N	N	N	N	N	N	N	N	N	N	N	N
CO	465	Ash Pump Pond	Arapahoe	N	N	N	N	N	Y	N	N	N	N	N	N
CO	465	South Ash Pond	Arapahoe	N	N	N	N	N	Y	N	N	N	N	N	N
CO	469	Center Ash Pond	Cherokee	N	N	N	N	N	Y	N	N	N	N	N	N
CO	469	East Ash Pond	Cherokee	N	N	N	N	N	Y	N	N	N	N	N	N
CO	469	East Polishing Pond	Cherokee	N	N	N	N	N	Y	N	N	N	N	N	N
CO	469	Emergency Spill Pond	Cherokee	N	N	N	N	N	Y	N	N	N	N	N	N
CO	469	West Ash Pond	Cherokee	N	N	N	N	N	Y	N	N	N	N	N	N
CO	469	West Polishing Pond	Cherokee	N	N	N	N	N	Y	N	N	N	N	N	N
CO	470	Ash Disposal Facility (ADF) Stormwater Retention Pond	Comanche	N	N	N	N	N	Y	N	N	N	N	N	N
CO	470	Ash Pond #1	Comanche	N	N	N	N	N	Y	N	N	N	N	N	N
CO	470	Ash Pond #2	Comanche	N	N	N	N	N	Y	N	N	N	N	N	N
CO	470	Ash Pond #3	Comanche	N	N	N	N	N	Y	N	N	N	N	N	N
CO	470	Polishing Pond (#4)	Comanche	N	N	N	N	N	Y	N	N	N	N	N	N
CO	477	East Ash Settling Pond	Valmont	N	N	N	N	N	Y	N	N	N	N	N	N

Exhibit H-4 List of Engineering Controls for Each of the 735 Surface Impoundments (Existing Units)															
State	Plant Code	Unit Name	Plant Name	Groundwater Monitoring	Liner					Leachate Collection System	Cap				PCM
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
CO	477	West Ash Settling Pond	Valmont	N	N	N	N	N	Y	N	N	N	N	N	N
CO	492	SPD-1	Martin Drake	N	N	N	N	N	N	N	N	N	N	N	N
CO	492	SPD-5	Martin Drake	N	N	N	N	N	N	N	N	N	N	N	N
CO	492	SPD-6	Martin Drake	N	N	N	N	N	N	N	N	N	N	N	N
CO	492	SPD-7	Martin Drake	N	N	N	N	N	N	N	N	N	N	N	N
CO	525	Ash Disposal Facility (ADF) Contact Storm Water Pond	Hayden	N	N	N	N	N	Y	N	N	N	N	N	N
CO	525	Common Wet Ash Settling Basin	Hayden	N	N	N	N	N	Y	N	N	N	N	N	N
CO	525	Fly Ash Decant Basin	Hayden	N	N	N	N	N	Y	N	N	N	N	N	N
CO	525	Intermediate Quality Pond	Hayden	N	N	N	N	N	Y	N	N	N	N	N	N
CO	527	Coal/Ash Settling Basin	Nucla	Y	N	N	N	N	Y	Y	N	N	N	N	N
CO	6248	Ash Disposal Facility (ADF)	Pawnee	N	N	N	N	N	Y	N	N	N	N	N	N
CO	6248	Evaporative Pond B	Pawnee	N	N	N	N	N	Y	N	N	N	N	N	N
CO	6248	Evaporative Pond C	Pawnee	N	N	N	N	N	Y	N	N	N	N	N	N
CO	6248	Intermediate Quality (IQ) Water Pond	Pawnee	N	N	N	N	N	Y	N	N	N	N	N	N
CO	6248	New Bottom Ash Water Recovery Pond	Pawnee	Y	N	N	N	N	Y	Y	N	N	N	N	N
CO	6761	North Bottom Ash Transfer Pond	Rawhide	N	N	N	N	N	Y	N	N	N	N	N	N
CO	6761	South Bottom Ash Transfer Pond	Rawhide	N	N	N	N	N	Y	N	N	N	N	N	N
DE	594	Sedimentation Pond	Indian River Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
DE	10030	Waste Water Pond	NRG Energy Center Dover	N	N	N	N	N	Y	N	N	N	N	N	N
FL	641	SPD-1	Crist	N	N	N	N	N	N	N	N	N	N	N	N
FL	641	SPD-5	Crist	N	N	N	N	N	N	N	N	N	N	N	N
FL	641	SPD-6	Crist	N	Y	N	N	N	N	N	N	N	N	N	N
FL	642	SPD-1	Scholz	N	N	N	N	N	N	N	N	N	N	N	N
FL	642	SPD-2	Scholz	N	N	N	N	N	N	N	N	N	N	N	N
FL	642	SPD-3	Scholz	N	N	N	N	N	N	N	N	N	N	N	N
FL	643	Ash Pond	Lansing Smith	N	N	N	N	N	N	N	N	N	N	N	N
FL	645	Longterm Flyash Pond	Big Bend	N	N	N	N	N	Y	N	N	N	N	N	N
FL	645	North Bottom Ash	Big Bend	N	Y	N	N	N	N	N	N	N	N	N	N
FL	645	North Economizer Ash Pond	Big Bend	N	Y	N	N	N	N	N	N	N	N	N	N
FL	645	North Recycle Pond	Big Bend	Y	N	N	N	N	Y	N	N	N	N	N	N
FL	645	Settling Pond	Big Bend	Y	N	N	N	N	Y	N	N	N	N	N	N
FL	645	South Bottom Ash Pond	Big Bend	N	Y	N	N	N	N	N	N	N	N	N	N
FL	645	South Economizer Ash Pond	Big Bend	N	Y	N	N	N	N	N	N	N	N	N	N
FL	645	South Recycle Pond	Big Bend	Y	N	N	N	N	Y	N	N	N	N	N	N
FL	663	SPD-1	Deerhaven Generating Station	N	N	N	N	N	N	N	N	N	N	N	N
GA	703	Ash Pond	Bowen	N	N	Y	N	N	N	N	N	N	N	N	N
GA	708	Ash Pond 1	Hammond	N	N	N	N	N	N	N	N	N	N	N	N
GA	708	Ash Pond 2	Hammond	N	N	N	N	N	N	N	N	N	N	N	N
GA	708	Ash Pond 4	Hammond	N	N	N	N	N	N	N	N	N	N	N	N
GA	709	Ash Pond B	Harlee Branch	N	N	N	N	N	N	N	N	N	N	N	N
GA	709	Ash Pond C	Harlee Branch	N	N	N	N	N	N	N	N	N	N	N	N
GA	709	Ash Pond D	Harlee Branch	N	N	N	N	N	N	N	N	N	N	N	N
GA	709	Ash Pond E	Harlee Branch	N	N	N	N	N	N	N	N	N	N	N	N
GA	710	Ash Pond 2	Jack McDonough	N	N	N	N	N	N	N	N	N	N	N	N
GA	710	Ash Pond 3	Jack McDonough	N	N	N	N	N	N	N	N	N	N	N	N
GA	710	Ash Pond 4	Jack McDonough	N	N	N	N	N	N	N	N	N	N	N	N
GA	727	Ash Pond 1	Mitchell	N	N	N	N	N	N	N	N	N	N	N	N
GA	727	Ash Pond 2	Mitchell	N	N	N	N	N	N	N	N	N	N	N	N
GA	727	Ash Pond A	Mitchell	N	N	N	N	N	N	N	N	N	N	N	N
GA	728	Ash Pond 1	Yates	N	N	N	N	N	N	N	N	N	N	N	N
GA	728	Ash Pond 2	Yates	N	N	N	N	N	N	N	N	N	N	N	N
GA	728	Ash Pond 3	Yates	N	N	N	N	N	N	N	N	N	N	N	N
GA	728	B' Pond	Yates	N	N	N	N	N	N	N	N	N	N	N	N
GA	728	Gypsum Solid Waste Facility	Yates	N	Y	N	N	N	N	N	N	N	N	N	N
GA	733	Ash Pond	Kraft	N	N	N	N	N	Y	N	N	N	N	N	N
GA	753	SPD-1	Crisp Plant	N	N	N	N	N	Y	N	N	N	N	N	N

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State	Plant Code	Unit Name	Plant Name	Groundwater Monitoring	Liner					Leachate Collection System	Cap				PCM
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
GA	6052	Ash Pond	Wansley	N	N	N	N	N	N	N	N	N	N	N	N
GA	6124	Ash Pond	McIntosh	N	N	N	N	N	Y	N	N	N	N	N	N
GA	6257	Ash Pond	Scherer	N	N	N	N	N	N	N	N	N	N	N	N
GA	6257	Settlement-Recycle Pond	Scherer	N	N	N	N	N	N	N	N	N	N	N	N
IA	1046	Ash Channel	Dubuque	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1047	Lower Ash Pond	Lansing	N	N	N	N	N	N	N	N	N	N	N	N
IA	1047	Main Ash Pond	Lansing	N	N	N	N	N	N	N	N	N	N	N	N
IA	1048	Emergency Ash Primary Settling Pond	ML Kapp	N	N	N	N	N	N	N	N	N	N	N	N
IA	1048	Emergency Ash Secondary Settling Pond	ML Kapp	N	N	N	N	N	N	N	N	N	N	N	N
IA	1048	Main Ash Primary Settling Pond	ML Kapp	N	N	N	N	N	N	N	N	N	N	N	N
IA	1048	Main Ash Secondary Settling Pond	ML Kapp	N	N	N	N	N	N	N	N	N	N	N	N
IA	1073	Ash Pond #1	Prairie Creek	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1073	Ash Pond #10	Prairie Creek	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1073	Ash Pond #2	Prairie Creek	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1073	Ash Pond #3	Prairie Creek	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1073	Ash Pond #4	Prairie Creek	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1073	Ash Pond #5	Prairie Creek	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1073	Ash Pond #6	Prairie Creek	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1073	Ash Pond #7	Prairie Creek	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1073	Ash Pond #8 - Plant Drains	Prairie Creek	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1073	Ash Pond #9 - Dumper Building	Prairie Creek	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1077	Main Ash Settling Pond	Sutherland	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1077	Unit 1 & 2 Initial Settling Pond	Sutherland	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1077	Unit 3 Initial Settling Pond	Sutherland	N	N	N	N	N	Y	N	N	N	N	N	N
IA	1081	North Ash Pond	Riverside	N	N	N	N	N	N	N	N	N	N	N	N
IA	1081	South Ash Pond	Riverside	N	N	N	N	N	N	N	N	N	N	N	N
IA	1082	North Surface Impoundment	Walter Scott Jr. Energy Center	N	N	N	N	N	N	N	N	N	N	N	N
IA	1082	South Surface Impoundment	Walter Scott Jr. Energy Center	N	N	N	N	N	N	N	N	N	N	N	N
IA	1091	Surface Impoundment 1	George Neal North	N	N	N	N	N	N	N	N	N	N	N	N
IA	1091	Surface Impoundment 2	George Neal North	N	N	N	N	N	N	N	N	N	N	N	N
IA	1091	Surface Impoundment 3	George Neal North	N	N	N	N	N	N	N	N	N	N	N	N
IA	1104	Economizer Ash Pond	Burlington	N	N	N	N	N	N	N	N	N	N	N	N
IA	1104	Lower Ash Pond	Burlington	N	N	N	N	N	N	N	N	N	N	N	N
IA	1104	Main Ash Pond	Burlington	N	N	N	N	N	N	N	N	N	N	N	N
IA	1104	Upper Ash Pond	Burlington	N	N	N	N	N	N	N	N	N	N	N	N
IA	1122	SPD-1	Ames Electric Services Power Plant	N	N	N	N	N	Y	N	N	N	N	N	N
IA	6254	Main Ash Pond	Ottumwa	N	N	N	N	N	N	N	N	N	N	N	N
IA	6664	Bottom Ash Pond	Louisa	N	N	Y	N	N	N	N	N	N	N	N	N
IA	6664	Louisa Surface Impoundment	Louisa	N	N	Y	N	N	N	N	N	N	N	N	N
IL	856	Ash Pond	ED Edwards	N	N	N	N	N	N	N	N	N	N	N	N
IL	856	Pond 2 - Ash Pond Settling	ED Edwards	N	N	N	N	N	N	N	N	N	N	N	N
IL	856	Pond 3 - Clarification Pond	ED Edwards	N	N	N	N	N	N	N	N	N	N	N	N
IL	861	Gypsum Management Facility Recycle Pond	Coffeen	N	Y	N	N	N	N	N	N	N	N	N	N
IL	874	SPD-1	Joliet 9	N	N	N	N	N	N	N	N	N	N	N	N
IL	874	SPD-2	Joliet 9	N	N	N	N	N	N	N	N	N	N	N	N
IL	876	Slag Field	Kincaid Generation LLC	N	N	N	N	N	N	N	N	N	N	N	N
IL	879	SPD-1	Powerton	N	N	N	N	N	N	N	N	N	N	N	N
IL	879	SPD-2	Powerton	N	N	N	N	N	N	N	N	N	N	N	N
IL	879	SPD-3	Powerton	N	N	N	N	N	N	N	N	N	N	N	N
IL	883	SPD-1	Waukegan	N	Y	N	N	N	N	N	N	N	N	N	N
IL	883	SPD-2	Waukegan	N	Y	N	N	N	N	N	N	N	N	N	N
IL	887	Ash Pond	Joppa Steam	N	N	N	N	N	N	N	N	N	N	N	N
IL	889	Ash Pond System	Baldwin Energy Complex	N	N	N	N	N	Y	N	N	N	N	N	N
IL	891	East Ash Pond	Havana	N	Y	N	N	N	N	N	N	N	N	N	N
IL	891	North Ash Pond System	Havana	N	N	N	N	N	Y	N	N	N	N	N	N
IL	892	Ash Pond System (2 cells)	Hennepin Power Station	N	N	N	N	N	Y	N	N	N	N	N	N
IL	898	East Ash Pond (2 cells)	Wood River	N	Y	N	N	N	N	N	N	N	N	N	N

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State	Plant Code	Unit Name	Plant Name	Groundwater Monitoring	Liner					Lechate Collection System	Cap				PCM
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
IL	898	West Ash Pond (2 cells) Cells 2E and 3	Wood River	N	N	Y	N	N	N	N	N	N	N	N	N
IL	963	Dallman Ash Pond	Dallman	N	N	N	N	N	N	N	N	N	N	N	N
IL	976	Fly Ash Disposal Pond	Marion Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
IL	976	Pond 1	Marion Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
IL	976	Pond 2	Marion Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
IL	976	Pond 3	Marion Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
IL	976	Pond 3A	Marion Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
IL	976	Pond 4	Marion Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
IL	976	Pond A-1	Marion Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
IL	976	Pond S-1	Marion Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
IL	976	Pond S-2	Marion Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
IL	976	Pond S-3	Marion Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
IL	976	Pond S-6	Marion Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
IL	976	South Fly Ash Pond	Marion Generating Station	N	N	N	N	N	Y	N	N	N	N	N	N
IL	6016	Recycle Pond	Duck Creek	N	N	Y	N	N	N	N	N	N	N	N	N
IL	6017	Primary Ash Pond	Newton	N	N	N	N	N	N	N	N	N	N	N	N
IL	6017	Secondary Ash Pond	Newton	N	N	N	N	N	N	N	N	N	N	N	N
IL	6238	SPD-1	Pearl Station	N	N	N	N	N	N	N	N	N	N	N	N
IN	983	South Fly Ash Runoff Pond Site 16	Clifty Creek	N	N	N	N	N	N	N	N	N	N	N	N
IN	983	West Bottom Ash Pond Site 16 (Regn 5)	Clifty Creek	N	N	N	N	N	N	N	N	N	N	N	N
IN	988	Boiler Slag Pond (U-4)	Tanners Creek	N	N	N	N	N	Y	N	N	N	N	N	N
IN	988	Bottom Ash Complex	Tanners Creek	N	N	N	N	N	N	N	N	N	N	N	N
IN	988	Fly Ash Pond	Tanners Creek	N	Y	N	N	N	N	N	N	N	N	N	N
IN	988	Fly Ash Pond - Clear Pond and Original (Lower Pond) Dike	Tanners Creek	N	Y	N	N	N	N	N	N	N	N	N	N
IN	988	Fly Ash Pond - Upper Pond	Tanners Creek	N	N	N	N	N	N	N	N	N	N	N	N
IN	990	Pond 1	Harding Street	N	N	N	N	N	N	N	N	N	N	N	N
IN	990	Pond 2	Harding Street	N	N	N	N	N	N	N	N	N	N	N	N
IN	990	Pond 3	Harding Street	N	N	N	N	N	N	N	N	N	N	N	N
IN	990	Pond 4	Harding Street	N	N	N	N	N	N	N	N	N	N	N	N
IN	990	Ponds 2A/2B	Harding Street	N	N	N	N	N	N	N	N	N	N	N	N
IN	991	A Pond	Eagle Valley	N	N	N	N	N	N	N	N	N	N	N	N
IN	991	B Pond	Eagle Valley	N	N	N	N	N	N	N	N	N	N	N	N
IN	991	C Pond	Eagle Valley	N	N	N	N	N	N	N	N	N	N	N	N
IN	991	D Pond	Eagle Valley	N	N	N	N	N	N	N	N	N	N	N	N
IN	994	Pond A - Active	AES Petersburg	N	N	N	N	N	N	N	N	N	N	N	N
IN	994	Pond A - Discharge	AES Petersburg	N	N	N	N	N	N	N	N	N	N	N	N
IN	995	Bottom Ash Pond	Bailly	N	N	N	N	N	Y	N	N	N	N	N	N
IN	995	Primary 1	Bailly	N	N	N	N	N	Y	N	N	N	N	N	N
IN	995	Primary 2	Bailly	N	N	N	N	N	Y	N	N	N	N	N	N
IN	995	Secondary 1	Bailly	N	N	N	N	N	Y	N	N	N	N	N	N
IN	995	Secondary 2	Bailly	N	N	N	N	N	Y	N	N	N	N	N	N
IN	997	Bottom Ash Area	Michigan City	N	N	N	N	N	Y	N	N	N	N	N	N
IN	997	Final Settling Pond	Michigan City	N	N	N	N	N	Y	N	N	N	N	N	N
IN	997	Primary 1	Michigan City	N	N	N	N	N	Y	N	N	N	N	N	N
IN	997	Primary 2	Michigan City	N	N	N	N	N	Y	N	N	N	N	N	N
IN	997	Secondary 1	Michigan City	N	N	N	N	N	Y	N	N	N	N	N	N
IN	997	Secondary 2	Michigan City	N	N	N	N	N	Y	N	N	N	N	N	N
IN	1001	Ash Disposal Area #1	Cayuga	N	N	N	N	N	N	N	N	N	N	N	N
IN	1001	Lined Ash Disposal Pond - Cell #1	Cayuga	N	Y	N	N	N	N	N	N	N	N	N	N
IN	1001	Primary Ash Settling Basin	Cayuga	N	N	N	N	N	N	N	N	N	N	N	N
IN	1001	Secondary Ash Settling Basin	Cayuga	N	N	N	N	N	N	N	N	N	N	N	N
IN	1004	Primary Ash Pond	Edwardsport	N	N	N	N	N	N	N	N	N	N	N	N
IN	1004	Secondary Ash Pond	Edwardsport	N	N	N	N	N	N	N	N	N	N	N	N
IN	1008	Ash Pond A	R. Gallagher	N	N	N	N	N	N	N	N	N	N	N	N
IN	1008	Secondary Ash Pond	R. Gallagher	N	N	N	N	N	N	N	N	N	N	N	N
IN	1010	Primary Ash Pond Cell A	Wabash River	N	N	N	N	N	N	N	N	N	N	N	N

Exhibit H-4 List of Engineering Controls for Each of the 735 Surface Impoundments (Existing Units)															
State	Plant Code	Unit Name	Plant Name	Groundwater Monitoring	Liner					Leachate Collection System	Cap				PCM
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
IN	1010	Primary Ash Pond Cell B	Wabash River	N	N	N	N	N	N	N	N	N	N	N	N
IN	1010	Secondary Ash Pond	Wabash River	N	N	N	N	N	N	N	N	N	N	N	N
IN	1010	South Ash Pond	Wabash River	N	Y	N	N	N	N	N	N	N	N	N	N
IN	1012	East Pond	F. B. Culley	N	N	N	N	N	N	N	N	N	N	N	N
IN	1040	SPD-5	Whitewater Valley	N	N	N	N	N	N	N	N	N	N	N	N
IN	1043	Bottom Ash Pond	Frank E. Ratts	N	N	N	N	N	N	N	N	N	N	N	N
IN	1043	Fly Ash Pond 1	Frank E. Ratts	N	N	N	N	N	N	N	N	N	N	N	N
IN	1043	Fly Ash Pond 2	Frank E. Ratts	N	N	N	N	N	N	N	N	N	N	N	N
IN	1043	Fly Ash Pond 3	Frank E. Ratts	N	N	N	N	N	N	N	N	N	N	N	N
IN	1043	Pond 1	Frank E. Ratts	N	N	N	N	N	N	N	N	N	N	N	N
IN	1043	Pond 2	Frank E. Ratts	N	N	N	N	N	Y	N	N	N	N	N	N
IN	1043	Pond 3	Frank E. Ratts	N	N	N	N	N	Y	N	N	N	N	N	N
IN	1043	Pond 4	Frank E. Ratts	N	N	N	N	N	Y	N	N	N	N	N	N
IN	6085	FGD Landfill Stormwater Runoff Pond	R.M. Schahfer	N	N	N	N	N	N	N	N	N	N	N	N
IN	6085	Gypsum Storage (Units 14&15)A	R.M. Schahfer	N	N	N	N	N	N	N	N	N	N	N	N
IN	6085	Gypsum Storage (Units 14&15)B	R.M. Schahfer	N	N	N	N	N	N	N	N	N	N	N	N
IN	6085	Material Storage Runoff Basin	R.M. Schahfer	N	N	N	N	N	N	N	N	N	N	N	N
IN	6085	Metal Cleaning Waste Basin	R.M. Schahfer	N	N	N	N	N	N	N	N	N	N	N	N
IN	6085	Recycle Basin	R.M. Schahfer	N	N	N	N	N	N	N	N	N	N	N	N
IN	6113	East Pond #1	Gibson	N	N	N	N	N	N	N	N	N	N	N	N
IN	6113	East Pond #2	Gibson	N	N	N	N	N	N	N	N	N	N	N	N
IN	6113	East Pond #3	Gibson	N	N	N	N	N	N	N	N	N	N	N	N
IN	6113	East Settling Basin	Gibson	N	N	N	N	N	N	N	N	N	N	N	N
IN	6113	North Ash Pond	Gibson	N	N	N	N	N	N	N	N	N	N	N	N
IN	6113	North Settling Basin	Gibson	N	N	N	N	N	N	N	N	N	N	N	N
IN	6137	Lower Ash Pond	A. B. Brown Generating Station	N	N	N	N	N	N	N	N	N	N	N	N
IN	6137	Upper Ash Pond	A. B. Brown Generating Station	N	N	N	N	N	N	N	N	N	N	N	N
IN	6166	Bottom Ash Complex	Rockport	N	N	N	N	N	N	N	N	N	N	N	N
IN	6705	EPRI 9	Warrick Power Plant	N	N	N	N	N	Y	N	N	N	N	N	N
KS	1239	Industrial Landfill-East and West Ponds	Riverton	Y	N	N	N	N	N	N	N	N	N	N	N
KS	1241	Bottom Ash Settling Pond	La Cygne	Y	N	Y	N	N	N	N	N	N	N	N	N
KS	1241	Scrubber Sludge Ponds	La Cygne	Y	N	Y	N	N	N	N	N	N	N	N	N
KS	1250	Area 1	Lawrence Energy Center	Y	N	N	N	N	N	N	N	N	N	N	N
KS	1250	Area 2	Lawrence Energy Center	Y	N	N	N	N	N	N	N	N	N	N	N
KS	1250	Area 3	Lawrence Energy Center	Y	N	Y	N	N	N	N	N	N	N	N	N
KS	1250	Area 4	Lawrence Energy Center	Y	N	N	N	N	N	N	N	N	N	N	N
KS	1252	Area 1	Tecumseh Energy Center	Y	N	N	N	N	N	N	N	N	N	N	N
KS	1252	Area 2	Tecumseh Energy Center	Y	N	N	N	N	N	N	N	N	N	N	N
KS	6064	N/A	Nearman Creek	Y	N	Y	N	N	N	N	N	N	N	N	N
KS	6068	Bottom Ash Lake Dam	Jeffrey Energy Center	Y	N	N	N	N	N	N	N	N	N	N	N
KS	6068	Bottom Ash Pond Dam	Jeffrey Energy Center	Y	N	N	N	N	N	N	N	N	N	N	N
KS	6068	Bottom Ash Settling Pond	Jeffrey Energy Center	Y	N	N	N	N	Y	N	N	N	N	N	N
KY	1353	Bottom Ash Complex	Big Sandy	N	N	N	N	N	N	N	N	N	N	N	N
KY	1353	Fly Ash	Big Sandy	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1353	Horseford Run Dam	Big Sandy	N	N	Y	N	N	N	N	N	N	N	N	N
KY	1355	Ash Pond	E.W. Brown	N	Y	N	N	N	N	N	N	N	N	N	N
KY	1355	Auxiliary Pond	E.W. Brown	N	Y	N	N	N	N	N	N	N	N	N	N
KY	1356	Ash Treatment Basin #1	Ghent	N	N	N	N	N	N	N	N	N	N	N	N
KY	1356	Ash Treatment Basin #2	Ghent	N	N	N	N	N	N	N	N	N	N	N	N
KY	1356	Gypsum Stack Surge/Reclaim Pond	Ghent	N	N	Y	N	N	N	N	N	N	N	N	N
KY	1356	Gypsum Stacking Facility	Ghent	N	N	N	N	N	N	N	N	N	N	N	N
KY	1356	Secondary Ash Treatment Basin	Ghent	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1357	Ash Pond Number 2	Green River	N	N	N	N	N	N	N	N	N	N	N	N
KY	1357	Finishing Pond Number 3	Green River	N	N	N	N	N	N	N	N	N	N	N	N
KY	1357	Former Ash Pond	Green River	N	N	N	N	N	N	N	N	N	N	N	N
KY	1357	Main Ash Pond	Green River	N	N	N	N	N	N	N	N	N	N	N	N
KY	1357	Scrubber Pond	Green River	N	N	N	N	N	N	N	N	N	N	N	N

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State	Plant Code	Unit Name	Plant Name	Groundwater Monitoring	Liner					Leachate Collection System	Cap				PCM
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
KY	1361	Ash Pond	Tyrone	N	N	N	N	N	N	N	N	N	N	N	N
KY	1361	Secondary Ash Pond	Tyrone	N	N	N	N	N	N	N	N	N	N	N	N
KY	1363	Basin Pond	Cane Run	N	N	N	N	N	N	N	N	N	N	N	N
KY	1363	Clearwell Pond	Cane Run	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1363	Dead Storage Pond	Cane Run	N	N	N	N	N	N	N	N	N	N	N	N
KY	1363	Emergency Pond	Cane Run	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1363	Main Ash Pond/E-Pond	Cane Run	N	N	N	N	N	N	N	N	N	N	N	N
KY	1364	Ash Pond	Mill Creek	N	N	N	N	N	N	N	N	N	N	N	N
KY	1364	Clearwell Pond	Mill Creek	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1364	Construction Run Off Pond	Mill Creek	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1364	Dead Storage Pond	Mill Creek	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1364	Emergency Pond	Mill Creek	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1374	SPD-1	Elmer Smith	N	N	N	N	N	N	N	N	N	N	N	N
KY	1374	SPD-2	Elmer Smith	N	N	N	N	N	N	N	N	N	N	N	N
KY	1374	SPD-4	Elmer Smith	N	Y	N	N	N	N	N	N	N	N	N	N
KY	1374	SPD-6	Elmer Smith	N	N	N	N	N	N	N	N	N	N	N	N
KY	1378	Fly Ash Extension Area Pond	Paradise	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1378	Scrubber Sludge Complex	Paradise	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1379	Ash Pond	Shawnee	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1379	Consolidated Waste Dry Stack	Shawnee	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1381	Active Ash Pond A	Kenneth C Coleman	N	N	N	N	N	N	N	N	N	N	N	N
KY	1381	Inactive Ash Pond C	Kenneth C Coleman	N	N	N	N	N	N	N	N	N	N	N	N
KY	1381	New Ash Pond	Kenneth C Coleman	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1382	Ash Pond No. 0855	HMP&L Station Two Henderson	N	N	N	N	N	N	N	N	N	N	N	N
KY	1382	Green Ash Pond	HMP&L Station Two Henderson	N	N	N	N	N	N	N	N	N	N	N	N
KY	1385	Dale Ash Pond #2	Dale Station	N	N	N	N	N	N	N	N	N	N	N	N
KY	1385	Dale Ash Pond #3	Dale Station	N	N	N	N	N	Y	N	N	N	N	N	N
KY	1385	Dale Ash Pond #4	Dale Station	N	N	N	N	N	N	N	N	N	N	N	N
KY	6018	East Bend Station Unit 1	East Bend Station	N	N	N	N	N	N	N	N	N	N	N	N
KY	6018	FGD Pond East	East Bend Station	N	N	N	N	N	Y	N	N	N	N	N	N
KY	6018	FGD Pond West	East Bend Station	N	N	N	N	N	Y	N	N	N	N	N	N
KY	6041	Spurlock Ash Pond	H L Spurlock Station	N	N	Y	N	N	N	N	N	N	N	N	N
KY	6071	Coal Combustion Waste Pond	Trimble Co.	N	N	Y	N	N	N	N	N	N	N	N	N
KY	6639	Ash Pond Dam #0980	R D Green	N	N	N	N	N	N	N	N	N	N	N	N
LA	51	Ash Basin No. 1	Dolet Hills	Y	N	Y	N	N	N	N	N	N	N	N	N
LA	51	Ash Basin No. 2	Dolet Hills	Y	N	Y	N	N	N	N	N	N	N	N	N
LA	51	Auxiliary Surge Pond	Dolet Hills	Y	N	Y	N	N	N	N	N	N	N	N	N
LA	51	Landfill Storm Water/Leachate	Dolet Hills	Y	N	Y	N	N	N	N	N	N	N	N	N
LA	51	Secondary Basin	Dolet Hills	Y	N	N	N	N	N	N	N	N	N	N	N
LA	51	Surge Pond No. 1	Dolet Hills	Y	N	Y	N	N	N	N	N	N	N	N	N
LA	51	Surge Pond No. 2	Dolet Hills	Y	N	Y	N	N	N	N	N	N	N	N	N
LA	6055	Bottom Ash Unit	Big Cajun 2	Y	N	Y	N	N	N	N	N	N	N	N	N
LA	6055	Fly Ash Unit	Big Cajun 2	Y	N	Y	N	N	N	N	N	N	N	N	N
LA	6055	Water Treatment Unit	Big Cajun 2	Y	N	Y	N	N	N	N	N	N	N	N	N
LA	6190	Bottom Ash Pond	Rodemacher	Y	N	Y	N	N	N	N	N	N	N	N	N
LA	6190	Fly Ash Pond	Rodemacher	Y	N	Y	N	N	N	N	N	N	N	N	N
LA	6190	Leachate Pond	Rodemacher	Y	Y	N	N	N	N	N	N	N	N	N	N
MA	1619	SPD-4	Brayton Point	N	Y	N	N	N	N	N	N	N	N	N	N
MA	1619	SPD-5	Brayton Point	N	Y	N	N	N	N	N	N	N	N	N	N
MA	1619	SPD-6	Brayton Point	N	Y	N	N	N	N	N	N	N	N	N	N
MD	602	SPD-5	Brandon Shores	N	Y	N	N	N	N	N	N	N	N	N	N
MD	602	SPD-6	Brandon Shores	N	Y	N	N	N	N	N	N	N	N	N	N
MD	1570	Ash Pond #3	R. Paul Smith Power Station	N	N	N	N	N	N	N	N	N	N	N	N
MD	1570	Ash Pond #4	R. Paul Smith Power Station	N	Y	N	N	N	N	N	N	N	N	N	N
MI	1702	DE Karn 1 and 2 Solid Waste Disposal Area	D.E. Karn	Y	N	N	N	N	N	N	N	N	N	N	N
MI	1702	Pond A	D.E. Karn	Y	N	N	N	N	N	N	N	N	N	N	N
MI	1720	East 7 & 8 Ponds	J.C. Weadock	Y	N	N	N	N	Y	N	N	N	N	N	N

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State	Plant Code	Unit Name	Plant Name	Groundwater Monitoring	Liner					Lechate Collection System	Cap				PCM
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
MI	1720	J.C. Weadock Fly Ash Dam	J.C. Weadock	Y	N	Y	N	N	N	N	N	N	N	N	N
MI	1720	Weadock Landfill Embankment	J.C. Weadock	Y	N	Y	N	N	N	N	N	N	N	N	N
MI	1720	West A - E Ponds	J.C. Weadock	Y	N	N	N	N	Y	N	N	N	N	N	N
MI	1723	Pond 1	J.R Whiting	Y	N	N	N	N	N	N	N	N	N	N	N
MI	1723	Pond 2	J.R Whiting	Y	N	N	N	N	N	N	N	N	N	N	N
MI	1723	Pond 6	J.R Whiting	Y	N	N	N	N	N	N	N	N	N	N	N
MI	1723	Ponds 3-5	J.R Whiting	Y	N	N	N	N	Y	N	N	N	N	N	N
MI	1731	Pond	Harbor Beach Power Plant	Y	N	N	N	N	Y	N	N	N	N	N	N
MI	1733	Bottom Ash Basin	Monroe Power Plant	Y	N	N	N	N	Y	N	N	N	N	N	N
MI	1733	Fly Ash Basin	Monroe Power Plant	Y	N	N	N	N	N	N	N	N	N	N	N
MI	1740	SPD-1	River Rouge	Y	N	N	N	N	N	N	N	N	N	N	N
MI	1743	Pond	St Clair Power Plant	Y	N	N	N	N	Y	N	N	N	N	N	N
MI	1745	Pond	Trenton Channel Power Plant	Y	N	N	N	N	Y	N	N	N	N	N	N
MI	1825	SPD-1	J B Sims	Y	N	Y	N	N	N	N	N	N	N	N	N
MI	1825	SPD-2	J B Sims	Y	N	Y	N	N	N	N	N	N	N	N	N
MI	1830	SPD-1	James De Young	Y	N	N	N	N	N	N	N	N	N	N	N
MI	1832	Unit 1	Erickson Station	Y	N	N	N	N	Y	N	N	N	N	N	N
MI	6034	Pond	Belle River	Y	N	N	N	N	Y	N	N	N	N	N	N
MN	1891	Cell E	Laskin Energy Center	N	Y	N	N	N	N	N	N	N	N	N	N
MN	1893	Complex: Pond 3, 4, and Bottom Ash Pond	Boswell Energy Center	N	N	Y	N	N	N	N	N	N	N	N	N
MN	1893	Wastewater Treatment Plant Pond	Boswell Energy Center	N	N	Y	N	N	N	N	N	N	N	N	N
MN	1904	Settling Ponds 1-4	Black Dog	N	N	N	N	N	N	N	N	N	N	N	N
MN	6090	Bottom Ash Pond	Sherburne County	N	N	Y	N	N	N	N	N	N	N	N	N
MN	6090	Pond 3 N	Sherburne County	N	Y	N	N	N	N	N	N	N	N	N	N
MN	6090	Pond No. 1	Sherburne County	N	N	Y	N	N	N	N	N	N	N	N	N
MN	6090	Pond No. 2	Sherburne County	N	N	Y	N	N	N	N	N	N	N	N	N
MN	6090	Recycle Basin	Sherburne County	N	N	N	N	N	Y	N	N	N	N	N	N
MN	6090	Unit No. 3 Dry Ash Landfill Basin	Sherburne County	N	N	N	N	N	Y	N	N	N	N	N	N
MO	2076	Ash Impoundment	Asbury	N	N	N	N	N	Y	N	N	N	N	N	N
MO	2076	Lower Pond	Asbury	N	N	N	N	N	N	N	N	N	N	N	N
MO	2076	Upper Pond	Asbury	N	N	N	N	N	N	N	N	N	N	N	N
MO	2079	Scrubber Waste Settling Pond	Hawthorn	N	N	N	N	N	Y	N	N	N	N	N	N
MO	2080	Ash Settling Pond	Montrose	N	N	N	N	N	Y	N	N	N	N	N	N
MO	2080	North Ash Pond	Montrose	N	N	N	N	N	Y	N	N	N	N	N	N
MO	2080	South Ash Pond	Montrose	N	N	N	N	N	Y	N	N	N	N	N	N
MO	2094	Fly Ash Settling Pond	Sibley	N	N	Y	N	N	N	N	N	N	N	N	N
MO	2094	Slag Settling Pond	Sibley	N	N	N	N	N	N	N	N	N	N	N	N
MO	2098	Settling Pond	Lake Road	N	N	N	N	N	Y	N	N	N	N	N	N
MO	2103	Bottom Ash Pond	Labadie	N	N	N	N	N	N	N	N	N	N	N	N
MO	2103	Fly Ash Pond	Labadie	N	Y	N	N	N	N	N	N	N	N	N	N
MO	2104	Bottom Ash Pond (3)	Meramec	N	N	N	N	N	N	N	N	N	N	N	N
MO	2104	New Fly Ash Pond	Meramec	N	Y	N	N	N	N	N	N	N	N	N	N
MO	2104	Old Fly Ash Pond	Meramec	N	Y	N	N	N	N	N	N	N	N	N	N
MO	2107	Bottom Ash Pond	Sioux	N	N	N	N	N	N	N	N	N	N	N	N
MO	2107	Fly Ash Pond	Sioux	N	Y	N	N	N	N	N	N	N	N	N	N
MO	2123	SPD-1	Columbia	N	N	N	N	N	N	N	N	N	N	N	N
MO	2132	Bottom Ash Pond	Independence Power & Light - Blue Valley Station	N	N	N	N	N	N	N	N	N	N	N	N
MO	2132	North Fly Ash Pond	Independence Power & Light - Blue Valley Station	N	N	N	N	N	N	N	N	N	N	N	N
MO	2161	Pond	James River Power Station	N	N	N	N	N	Y	N	N	N	N	N	N
MO	2167	Ash Pond 1	New Madrid	N	N	N	N	N	N	N	N	N	N	N	N
MO	2167	Ash Pond 2	New Madrid	N	Y	N	N	N	N	N	N	N	N	N	N
MO	2167	Slag Pond 1	New Madrid	N	N	N	N	N	N	N	N	N	N	N	N
MO	2167	Slag Pond 2	New Madrid	N	N	N	N	N	N	N	N	N	N	N	N
MO	2168	Ash - 2 Landfill	Thomas Hill	N	N	N	N	N	Y	N	N	N	N	N	N
MO	2168	Ash -3 Landfill	Thomas Hill	N	N	N	N	N	Y	N	N	N	N	N	N

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					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
MO	2168	Ash Pond Cell 1 - Upper	Thomas Hill	N	N	N	N	N	Y	N	N	N	N	N	N
MO	2168	Ash Pond Cell 2 - Middle	Thomas Hill	N	N	N	N	N	N	N	N	N	N	N	N
MO	2168	Ash Pond Cell 3 - Lowest	Thomas Hill	N	N	N	N	N	Y	N	N	N	N	N	N
MO	2168	Ash Pond Slag Dewatering	Thomas Hill	N	N	N	N	N	N	N	N	N	N	N	N
MO	2169	SPD-2	Chamois	N	N	N	N	N	N	N	N	N	N	N	N
MO	2171	SPD-1	Missouri City	N	N	N	N	N	Y	N	N	N	N	N	N
MO	6155	Ash Pond	Rush Island	N	N	N	N	N	N	N	N	N	N	N	N
MO	6195	SPD-1	Southwest Power Station	N	N	Y	N	N	N	N	N	N	N	N	N
MO	6195	SPD-2	Southwest Power Station	N	N	Y	N	N	N	N	N	N	N	N	N
MO	6768	Bottom Ash Pond	Sikeston Power Station	N	N	Y	N	N	N	N	N	N	N	N	N
MO	6768	Fly Ash Pond	Sikeston Power Station	N	N	Y	N	N	N	N	N	N	N	N	N
MS	2049	Ash Pond	Jack Watson	N	N	N	N	N	N	N	N	N	N	N	N
MS	6061	SPD-4	R D Morrow	N	N	N	N	N	Y	N	N	N	N	N	N
MS	6061	SPD-5	R D Morrow	N	N	N	N	N	Y	N	N	N	N	N	N
MS	6073	EPRI 7	Victor J. Daniel Jr	N	N	N	N	N	Y	N	N	N	N	N	N
MS	55076	SPD-1	Red Hills Generating Facility	N	N	N	N	N	Y	N	N	N	N	N	N
MT	2187	SPD-1	J E Corette Plant	N	N	N	N	N	Y	N	N	N	N	N	N
MT	2187	SPD-2	J E Corette Plant	N	N	N	N	N	Y	N	N	N	N	N	N
MT	6076	Units 1 & 2 A Pond	Colstrip	N	N	N	N	N	N	N	N	N	N	N	N
MT	6076	Units 1 & 2 B Fly Ash Pond	Colstrip	N	N	N	N	N	Y	N	N	N	N	N	N
MT	6076	Units 1 & 2 Bottom Ash Pond	Colstrip	N	Y	N	N	N	N	N	N	N	N	N	N
MT	6076	Units 1 & 2 Stage Two Evaporation Ponds (STEP)	Colstrip	N	Y	N	N	N	N	N	N	N	N	N	N
MT	6076	Units 3 & 4 Bottom Ash Pond	Colstrip	N	N	N	N	N	Y	N	N	N	N	N	N
MT	6076	Units 3 & 4 Effluent Holding Pond (EHP)	Colstrip	N	N	N	N	N	N	N	N	N	N	N	N
MT	6089	SPD-1	Lewis & Clark	N	N	Y	N	N	N	N	N	N	N	N	N
MT	6089	SPD-2	Lewis & Clark	N	N	Y	N	N	N	N	N	N	N	N	N
MT	6089	SPD-3	Lewis & Clark	N	N	Y	N	N	N	N	N	N	N	N	N
MT	6089	SPD-4	Lewis & Clark	N	N	Y	N	N	N	N	N	N	N	N	N
MT	6089	SPD-5	Lewis & Clark	N	Y	N	N	N	N	N	N	N	N	N	N
NC	2706	1964 Pond	Asheville Steam Electric Plant	N	Y	N	N	N	N	N	N	N	N	N	N
NC	2706	1982 Pond	Asheville Steam Electric Plant	N	N	N	N	N	N	N	N	N	N	N	N
NC	2708	1978 Ash Pond	Cape Fear Steam Electric Plant	N	N	N	N	N	N	N	N	N	N	N	N
NC	2708	1985 Ash Pond	Cape Fear Steam Electric Plant	N	N	N	N	N	N	N	N	N	N	N	N
NC	2709	1980 Pond	H.F. Lee Plant	N	N	N	N	N	Y	N	N	N	N	N	N
NC	2709	Active Ash Pond	H.F. Lee Plant	N	N	N	N	N	N	N	N	N	N	N	N
NC	2712	Ash Pond	Roxboro Steam Electric Plant	N	N	N	N	N	N	N	N	N	N	N	N
NC	2712	FGD Flush Pond	Roxboro Steam Electric Plant	N	Y	N	N	N	N	Y	N	N	N	N	N
NC	2712	FGD Settling Pond	Roxboro Steam Electric Plant	N	Y	N	N	N	N	Y	N	N	N	N	N
NC	2712	West Ash Pond Dam & Dikes 1, 2,,& 4	Roxboro Steam Electric Plant	N	N	N	N	N	Y	N	N	N	N	N	N
NC	2713	1971 Pond	L.V. Sutton Electric Plant	N	N	N	N	N	N	N	N	N	N	N	N
NC	2713	1984 Pond	L.V. Sutton Electric Plant	N	N	Y	N	N	N	N	N	N	N	N	N
NC	2718	Active Ash Basin	G G Allen	N	N	N	N	N	N	N	N	N	N	N	N
NC	2718	East Dike - Active Ash Basin	G G Allen	N	N	N	N	N	N	N	N	N	N	N	N
NC	2718	North Dike - Active Ash Basin	G G Allen	N	N	N	N	N	N	N	N	N	N	N	N
NC	2720	Additional Primary Cell Basin	Buck	N	N	N	N	N	N	N	N	N	N	N	N
NC	2720	Old Primary Cell	Buck	N	N	N	N	N	N	N	N	N	N	N	N
NC	2720	Secondary Pond	Buck	N	N	N	N	N	N	N	N	N	N	N	N
NC	2721	Active Ash Pond	Cliffside	N	N	N	N	N	N	N	N	N	N	N	N
NC	2727	Active Ash Pond	Marshall	N	N	N	N	N	N	N	N	N	N	N	N
NC	2732	Primary Ash Disposal Pond	Riverbend	N	N	N	N	N	N	N	N	N	N	N	N
NC	2732	Secondary Pond	Riverbend	N	N	N	N	N	N	N	N	N	N	N	N
NC	6250	1982 Pond	Mayo Electric Generating Facility	N	N	N	N	N	N	N	N	N	N	N	N
NC	8042	Active Ash Pond	Belews Creek Steam Station	N	N	N	N	N	N	N	N	N	N	N	N
ND	2817	Ash Pond #1	Leland Olds	Y	N	N	N	N	N	Y	N	N	N	N	N
ND	2817	Ash Pond #2	Leland Olds	Y	N	N	N	N	N	Y	N	N	N	N	N
ND	2817	Ash Pond #3	Leland Olds	Y	N	N	N	N	N	Y	N	N	N	N	N

Exhibit H-4 List of Engineering Controls for Each of the 735 Surface Impoundments (Existing Units)															
State	Plant Code	Unit Name	Plant Name	Groundwater Monitoring	Liner					Leachate Collection System	Cap				PCM
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
ND	2823	30 Year Ponds (Cell 2)	Milton R. Young Station	Y	N	Y	N	N	N	Y	N	N	N	N	N
ND	2823	Cell 1	Milton R. Young Station	Y	N	Y	N	N	N	Y	N	N	N	N	N
ND	2823	Horseshoe Pit Evaporation Pond	Milton R. Young Station	Y	N	N	N	N	Y	Y	N	N	N	N	N
ND	2823	Unit 1 Alternative Bottom Ash Pond	Milton R. Young Station	Y	N	Y	N	N	N	Y	N	N	N	N	N
ND	2824	Middle Bottom Ash Pond/Retention Cell	Stanton	Y	N	N	N	N	Y	Y	N	N	N	N	N
ND	2824	North Bottom Ash Pond/Cell	Stanton	Y	N	N	N	N	Y	Y	N	N	N	N	N
ND	6030	Ash Pond 91	Coal Creek	Y	N	N	N	N	Y	Y	N	N	N	N	N
ND	6030	Upstream Raise/Ash Pond 92/SW Section 16	Coal Creek	Y	N	N	N	N	Y	Y	N	N	N	N	N
ND	8222	Ash Pond	Coyote	Y	N	N	N	N	Y	Y	N	N	N	N	N
ND	8222	Nelson Pond	Coyote	Y	N	N	N	N	Y	Y	N	N	N	N	N
ND	8222	Sluice Pond	Coyote	Y	N	N	N	N	Y	Y	N	N	N	N	N
NE	60	SPD-1	Whelan Energy Center	N	N	N	N	N	N	N	N	N	N	N	N
NE	2291	SPD-1	North Omaha	N	Y	N	N	N	N	N	N	N	N	N	N
NE	2291	SPD-2	North Omaha	N	Y	N	N	N	N	N	N	N	N	N	N
NE	6096	SPD-1	Nebraska City	N	N	N	N	N	N	N	N	N	N	N	N
NE	6096	SPD-2	Nebraska City	N	N	N	N	N	N	N	N	N	N	N	N
NH	2364	SPD-3	Merrimack	N	N	N	N	N	N	N	N	N	N	N	N
NH	2364	SPD-4	Merrimack	N	N	N	N	N	N	N	N	N	N	N	N
NM	87	Emergency Scrubber Pond	Escalante	N	N	N	N	N	Y	N	N	N	N	N	N
NM	87	Evaporation Pond 1a + 1b	Escalante	N	N	N	N	N	Y	N	N	N	N	N	N
NM	87	Evaporation Ponds 2-5	Escalante	N	N	N	N	N	Y	N	N	N	N	N	N
NM	87	Management Units 3 & 4 Bottom Ash	Escalante	N	N	N	N	N	Y	N	N	N	N	N	N
NM	2442	Lined Ash Impoundment	Four Corners	N	Y	N	N	N	N	N	N	N	N	N	N
NM	2442	Lined Water Impoundment	Four Corners	N	Y	N	N	N	N	N	N	N	N	N	N
NM	2442	Low Volume Waste Water Pond	Four Corners	N	N	N	N	N	Y	N	N	N	N	N	N
NM	2442	Low Volume Waste Water System Decant Cells	Four Corners	N	N	N	N	N	Y	N	N	N	N	N	N
NM	2442	Upper Retention Sump	Four Corners	N	N	N	N	N	Y	N	N	N	N	N	N
NV	2324	Pond B1	Reid Gardner	Y	Y	N	N	N	N	Y	N	N	N	N	N
NV	2324	Pond B2	Reid Gardner	Y	Y	N	N	N	N	Y	N	N	N	N	N
NV	2324	Pond B3	Reid Gardner	Y	Y	N	N	N	N	Y	N	N	N	N	N
NV	2324	Pond E1	Reid Gardner	Y	Y	N	N	N	N	Y	N	N	N	N	N
NV	2324	Pond E2	Reid Gardner	Y	Y	N	N	N	N	Y	N	N	N	N	N
NV	2324	Pond F	Reid Gardner	Y	Y	N	N	N	N	Y	N	N	N	N	N
NY	2527	SPD-1	AES Greenidge LLC	Y	N	N	N	N	N	N	N	N	N	N	N
NY	2527	SPD-2	AES Greenidge LLC	Y	N	N	N	N	N	N	N	N	N	N	N
NY	2549	North Equalization Basin	CR Huntley Generating Station	Y	N	N	N	N	Y	N	N	N	N	N	N
NY	2549	South Equalization Basin	CR Huntley Generating Station	Y	N	N	N	N	Y	N	N	N	N	N	N
NY	2549	South Settling Pond System	CR Huntley Generating Station	Y	N	N	N	N	Y	N	N	N	N	N	N
NY	2554	Equalization Basin	Dunkirk Generating Plant	Y	N	N	N	N	Y	N	N	N	N	N	N
NY	2554	Settling Pond System	Dunkirk Generating Plant	Y	N	N	N	N	Y	N	N	N	N	N	N
NY	6082	SPD-5	AES Somerset LLC	Y	N	N	N	N	Y	N	N	N	N	N	N
OH	2828	Bottom Ash Complex	Cardinal	N	N	N	N	N	N	N	N	N	N	N	N
OH	2828	Fly Ash Reservoir 2	Cardinal	N	N	N	N	N	N	N	N	N	N	N	N
OH	2830	Ash Pond B	Walter C Beckjord	N	N	N	N	N	N	N	N	N	N	N	N
OH	2830	Ash Pond C	Walter C Beckjord	N	N	N	N	N	N	N	N	N	N	N	N
OH	2832	Ash Basin A	Miami Fort	N	N	N	N	N	N	N	N	N	N	N	N
OH	2832	Ash Basin B	Miami Fort	N	N	N	N	N	N	N	N	N	N	N	N
OH	2835	SPD-1	Ashtabula	N	N	N	N	N	N	N	N	N	N	N	N
OH	2836	SPD-1	Avon Lake	N	N	N	N	N	N	N	N	N	N	N	N
OH	2836	SPD-2	Avon Lake	N	N	N	N	N	N	N	N	N	N	N	N
OH	2837	SPD-1	Eastlake	N	N	N	N	N	N	N	N	N	N	N	N
OH	2838	SPD-1	Lake Shore	N	N	N	N	N	N	N	N	N	N	N	N
OH	2840	Ash Pond Complex	Conesville	N	N	N	N	N	N	N	N	N	N	N	N
OH	2843	[blank]	Picway	N	N	N	N	N	Y	N	N	N	N	N	N
OH	2848	East Primary Settling Pond	O H Hutchings	N	N	N	N	N	N	N	N	N	N	N	N
OH	2848	Secondary Settling Pond	O H Hutchings	N	N	N	N	N	N	N	N	N	N	N	N

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State	Plant Code	Unit Name	Plant Name	Groundwater Monitoring	Liner					Leachate Collection System	Cap				PCM
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
OH	2848	West Primary Settling Pond	O H Hutchings	N	N	N	N	N	N	N	N	N	N	N	N
OH	2850	Ash Pond No. 10	J M Stuart	N	N	Y	N	N	N	N	N	N	N	N	N
OH	2850	Ash Pond No. 3A	J M Stuart	N	N	Y	N	N	N	N	N	N	N	N	N
OH	2866	SPD-1	W H Sammis	N	N	N	N	N	N	N	N	N	N	N	N
OH	2866	SPD-2	W H Sammis	N	N	N	N	N	N	N	N	N	N	N	N
OH	2872	Lower Fly Ash Dam	Muskingum River	N	N	N	N	N	N	N	N	N	N	N	N
OH	2872	Middle Fly Ash Pond	Muskingum River	N	N	N	N	N	N	N	N	N	N	N	N
OH	2872	Unit 1-4 Bottom Ash Pond Dam	Muskingum River	N	N	N	N	N	N	N	N	N	N	N	N
OH	2872	Upper Fly Ash Pond	Muskingum River	N	N	N	N	N	N	N	N	N	N	N	N
OH	2876	Bottom Ash Pond	Kyger Creek	N	N	N	N	N	N	N	N	N	N	N	N
OH	2876	South Fly Ash Pond	Kyger Creek	N	N	N	N	N	N	N	N	N	N	N	N
OH	2878	SPD-1	Bay Shore	N	N	N	N	N	N	N	N	N	N	N	N
OH	6019	Wastewater Pond Complex	W H Zimmer	N	N	Y	N	N	N	N	N	N	N	N	N
OH	6031	Bottom Ash Pond	Killen Station	N	N	N	N	N	Y	N	N	N	N	N	N
OH	6031	Fly Ash Pond	Killen Station	N	N	N	N	N	Y	N	N	N	N	N	N
OH	8102	Bottom Ash Pond	General James M. Gavin	N	N	N	N	N	N	N	N	N	N	N	N
OH	8102	Stingy Run Ash Disposal Pond	General James M. Gavin	N	N	N	N	N	N	N	N	N	N	N	N
OK	165	SPD-12	GRDA	N	N	N	N	N	N	N	N	N	N	N	N
OK	2952	SPD-1	Muskogee	N	N	Y	N	N	N	N	N	N	N	N	N
OK	2952	SPD-3	Muskogee	N	N	N	N	N	N	N	N	N	N	N	N
OK	2952	SPD-6	Muskogee	N	N	N	N	N	Y	N	N	N	N	N	N
OK	2963	Bottom Ash Pond	Northeastern	N	N	Y	N	N	N	N	N	N	N	N	N
OK	6095	SPD-4	Sooner	N	N	Y	N	N	N	N	N	N	N	N	N
OK	6772	North Bottom Ash Unit	Hugo	N	N	Y	N	N	N	N	N	N	N	N	N
OK	6772	North Fly Ash	Hugo	N	N	Y	N	N	N	N	N	N	N	N	N
OK	6772	South Bottom Ash	Hugo	N	N	Y	N	N	N	N	N	N	N	N	N
OK	6772	South Fly Ash Unit	Hugo	N	N	Y	N	N	N	N	N	N	N	N	N
PA	3098	SPD-1	Elrama Power Plant	Y	N	N	N	N	Y	N	N	N	N	N	N
PA	3098	SPD-2	Elrama Power Plant	Y	N	N	N	N	Y	N	N	N	N	N	N
PA	3098	SPD-4	Elrama Power Plant	Y	N	N	N	N	Y	N	N	N	N	N	N
PA	3113	SPD-1	Portland	Y	N	N	N	N	N	N	N	N	N	N	N
PA	3113	SPD-2	Portland	Y	N	N	N	N	N	N	N	N	N	N	N
PA	3118	SPD-3	Conemaugh	Y	N	Y	N	N	N	N	N	N	N	N	N
PA	3118	SPD-4	Conemaugh	Y	N	Y	N	N	N	N	N	N	N	N	N
PA	3118	SPD-5	Conemaugh	Y	N	Y	N	N	N	N	N	N	N	N	N
PA	3118	SPD-6	Conemaugh	Y	N	Y	N	N	N	N	N	N	N	N	N
PA	3122	Ash Disposal Site - Polishing Pond	Homer City Station	Y	N	N	N	N	Y	N	N	N	N	N	N
PA	3122	Ash Disposal Site - Treatment Pond #1	Homer City Station	Y	N	N	N	N	Y	N	N	N	N	N	N
PA	3122	Ash Disposal Site - Treatment Pond #2	Homer City Station	Y	N	N	N	N	Y	N	N	N	N	N	N
PA	3122	Ash Recycle Pond #1	Homer City Station	Y	N	N	N	N	Y	N	N	N	N	N	N
PA	3122	Ash Recycle Pond #2	Homer City Station	Y	N	N	N	N	Y	N	N	N	N	N	N
PA	3122	Ash Recycle Pond #3	Homer City Station	Y	N	N	N	N	Y	N	N	N	N	N	N
PA	3122	Ash Recycle Pond #4	Homer City Station	Y	N	N	N	N	Y	N	N	N	N	N	N
PA	3122	Coal Refuse Disposal Site - Stage I & II Pond	Homer City Station	Y	N	N	N	N	Y	N	N	N	N	N	N
PA	3122	Coal Refuse Disposal Site - Stage III & IV Pond	Homer City Station	Y	N	N	N	N	Y	N	N	N	N	N	N
PA	3122	Coal Refuse Disposal Site - Storage Pond #1	Homer City Station	Y	N	N	N	N	Y	Y	N	N	N	N	N
PA	3122	Coal Refuse Disposal Site - Storage Pond #2	Homer City Station	Y	N	N	N	N	Y	Y	N	N	N	N	N
PA	3131	SPD-1	Shawville	Y	Y	N	N	N	N	N	N	N	N	N	N
PA	3131	SPD-2	Shawville	Y	Y	N	N	N	N	N	N	N	N	N	N
PA	3136	SPD-10	Keystone	Y	Y	N	N	N	N	N	N	N	N	N	N
PA	3136	SPD-13	Keystone	Y	N	N	N	N	Y	N	N	N	N	N	N
PA	3136	SPD-14	Keystone	Y	N	N	N	N	Y	N	N	N	N	N	N
PA	3136	SPD-7	Keystone	Y	N	Y	N	N	N	N	N	N	N	N	N
PA	3136	SPD-8	Keystone	Y	N	Y	N	N	N	N	N	N	N	N	N
PA	3136	SPD-9	Keystone	Y	N	Y	N	N	N	N	N	N	N	N	N
PA	3138	SPD-1	New Castle Plant	Y	N	N	N	N	N	N	N	N	N	N	N

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State	Plant Code	Unit Name	Plant Name	Groundwater Monitoring	Liner					Leachate Collection System	Cap				PCM
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
PA	3138	SPD-2	New Castle Plant	Y	N	N	N	N	N	N	N	N	N	N	N
PA	3140	Ash Basin No.6	PPL Brunner Island	Y	N	N	N	N	Y	N	N	N	N	N	N
PA	3140	Equalizati pond	PPL Brunner Island	Y	N	N	N	N	Y	N	N	N	N	N	N
PA	3149	Ash Basin No. 1	PPL Montour	Y	N	N	N	N	Y	N	N	N	N	N	N
PA	3152	Residual Waste Ash Basin No. 1	Sunbury Generation LP	Y	N	N	N	N	N	N	N	N	N	N	N
PA	3179	SPD-1	Hatfields Ferry Power Station	Y	N	N	N	N	N	N	N	N	N	N	N
PA	3179	SPD-2	Hatfields Ferry Power Station	Y	N	N	N	N	N	N	N	N	N	N	N
PA	6094	East HDS (Decommissioned in 2003) (Add this unit to DB)	Bruce Mansfield	Y	N	N	N	N	N	N	N	N	N	N	N
PA	6094	Little Blue Run Dam	Bruce Mansfield	Y	N	N	N	N	N	N	N	N	N	N	N
PA	6094	North LDS Pond (N-LDS)	Bruce Mansfield	Y	N	N	N	N	N	N	N	N	N	N	N
PA	6094	South LDS Pond (S-LDS)	Bruce Mansfield	Y	N	N	N	N	N	N	N	N	N	N	N
PA	6094	West HDS Pond (W-HPDS)	Bruce Mansfield	Y	N	N	N	N	N	N	N	N	N	N	N
PA	8226	SPD-4	Cheswick Power Plant	Y	N	Y	N	N	N	N	N	N	N	N	N
PA	8226	SPD-5	Cheswick Power Plant	Y	N	Y	N	N	N	N	N	N	N	N	N
SC	130	Bottom Ash 1	Cross	N	N	Y	N	N	N	N	N	N	N	N	N
SC	130	Bottom Ash 2	Cross	N	N	Y	N	N	N	N	N	N	N	N	N
SC	130	Gypsum Pond	Cross	N	N	Y	N	N	N	N	N	N	N	N	N
SC	3251	Pond	HB Robinson / Darlington Electric Power Plant	N	N	N	N	N	N	N	N	N	N	N	N
SC	3264	Primary Active Ash Pond	W. S. Lee	N	N	N	N	N	N	N	N	N	N	N	N
SC	3264	Secondary Ash Pond	W. S. Lee	N	N	N	N	N	N	N	N	N	N	N	N
SC	3280	Ash Pond	Canadys Steam	N	N	N	N	N	N	N	N	N	N	N	N
SC	3280	Inactive Ash Pond	Canadys Steam	N	N	N	N	N	N	N	N	N	N	N	N
SC	3280	Polishing Pond	Canadys Steam	N	N	N	N	N	N	N	N	N	N	N	N
SC	3295	Ash Pond	Urquhart	N	N	N	N	N	N	N	N	N	N	N	N
SC	3295	Ash Pond 1	Urquhart	N	N	N	N	N	Y	N	N	N	N	N	N
SC	3295	Ash Pond 2	Urquhart	N	N	N	N	N	Y	N	N	N	N	N	N
SC	3297	Ash Pond No. 1	Waterree	N	N	N	N	N	N	N	N	N	N	N	N
SC	3297	Ash Pond No. 2	Waterree	N	N	N	N	N	N	N	N	N	N	N	N
SC	3319	Ash Pond A	Jefferies	N	N	N	N	N	N	N	N	N	N	N	N
SC	3319	Ash Pond B	Jefferies	N	N	N	N	N	N	N	N	N	N	N	N
SC	6249	Ash Pond A	Winyah	N	N	N	N	N	N	N	N	N	N	N	N
SC	6249	Ash Pond B	Winyah	N	N	N	N	N	N	N	N	N	N	N	N
SC	6249	South Ash Pond	Winyah	N	N	N	N	N	N	N	N	N	N	N	N
SC	6249	Unit 2 Slurry Pond	Winyah	N	N	N	N	N	N	N	N	N	N	N	N
SC	6249	Unit 3 & 4 Slurry Pond	Winyah	N	N	N	N	N	N	N	N	N	N	N	N
SC	6249	West Ash Pond	Winyah	N	N	N	N	N	N	N	N	N	N	N	N
SD	3325	SPD-1	Ben French	N	N	Y	N	N	N	N	N	N	N	N	N
SD	6098	SPD-2	Big Stone	N	N	N	N	N	N	N	N	N	N	N	N
TN	3393	East Ash Disposal	Allen Steam Plant	N	N	N	N	N	Y	N	N	N	N	N	N
TN	3393	East Ash Stilling Pond	Allen Steam Plant	N	N	N	N	N	Y	N	N	N	N	N	N
TN	3396	Bottom Ash Disposal Area 1	Bull Run	N	N	N	N	N	Y	N	N	N	N	N	N
TN	3396	Dry Fly Ash Disposal Area	Bull Run	N	N	N	N	N	Y	N	N	N	N	N	N
TN	3396	Fly Ash Pond & Stilling Basin Area 2	Bull Run	N	N	N	N	N	Y	N	N	N	N	N	N
TN	3396	Gypsum Disposal Area 2A	Bull Run	N	N	N	N	N	Y	N	N	N	N	N	N
TN	3399	Ash Pond	Cumberland	N	N	N	N	N	Y	N	N	N	N	N	N
TN	3399	Dry Ash Stack	Cumberland	N	N	N	N	N	Y	N	N	N	N	N	N
TN	3399	Gypsum Storage Area (North/South)	Cumberland	N	N	N	N	N	Y	N	N	N	N	N	N
TN	3403	Bottom Ash Pond A	Gallatin	N	N	N	N	N	Y	N	N	N	N	N	N
TN	3403	Fly Ash Pond E	Gallatin	N	N	N	N	N	Y	N	N	N	N	N	N
TN	3403	Stilling Pond B, C, D	Gallatin	N	N	N	N	N	Y	N	N	N	N	N	N
TN	3405	Bottom Ash Pond	John Sevier	N	N	N	N	N	Y	N	N	N	N	N	N
TN	3405	Dry Ash Stack	John Sevier	N	N	N	N	N	Y	N	N	N	N	N	N
TN	3406	Ash Disposal Area 2	Johnsonville	N	N	N	N	N	Y	N	N	N	N	N	N
TN	3406	DuPont Road Dredge Cell	Johnsonville	N	N	N	N	N	N	N	N	N	N	N	N
TN	3407	Main Ash Pond	Kingston	N	N	N	N	N	Y	N	N	N	N	N	N

Exhibit H-4 List of Engineering Controls for Each of the 735 Surface Impoundments (Existing Units)															
State	Plant Code	Unit Name	Plant Name	Groundwater Monitoring	Liner					Lechate Collection System	Cap				PCM
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
TN	3407	Stilling Pond	Kingston	N	N	N	N	N	Y	N	N	N	N	N	N
TX	127	Pond #23	Oklauion	N	N	N	N	N	Y	N	N	N	N	N	N
TX	127	Sludge Pond	Oklauion	N	N	N	N	N	Y	N	N	N	N	N	N
TX	127	Wastewater Evaporation Pond 6	Oklauion	N	N	Y	N	N	N	N	N	N	N	N	N
TX	298	Bottom Ash Cooling Pond	Limestone	N	N	N	N	N	Y	N	N	N	N	N	N
TX	298	FGD Emergency Pond E	Limestone	N	N	N	N	N	Y	N	N	N	N	N	N
TX	3470	Flue Gas Desulfurization Emergency Pond (E-Pond)	W. A. Parish	N	N	N	N	N	Y	N	N	N	N	N	N
TX		Unit 5 Bottom Ash Overflow Basin	W. A. Parish	N	N	N	N	N	Y	N	N	N	N	N	N
TX	3470	Unit 6 Bottom Ash Overflow Basin	W. A. Parish	N	N	N	N	N	Y	N	N	N	N	N	N
TX	3470	Unit 7 Bottom Ash Overflow Basin	W. A. Parish	N	N	N	N	N	Y	N	N	N	N	N	N
TX	3470	Unit 8 Bottom Ash Overflow Basin	W. A. Parish	N	N	N	N	N	Y	N	N	N	N	N	N
TX	3497	SPD-4	Big Brown	N	N	Y	N	N	N	N	N	N	N	N	N
TX	3497	SPD-5	Big Brown	N	N	N	N	N	N	N	N	N	N	N	N
TX	6136	SPD-1	Gibbons Creek	N	N	Y	N	N	N	N	N	N	N	N	N
TX	6136	SPD-2	Gibbons Creek	N	N	Y	N	N	N	N	N	N	N	N	N
TX	6136	SPD-3	Gibbons Creek	N	N	Y	N	N	N	N	N	N	N	N	N
TX	6136	SPD-5	Gibbons Creek	N	Y	N	N	N	N	N	N	N	N	N	N
TX	6139	Active Bottom Ash Storage	Welsh	N	Y	N	N	N	N	N	N	N	N	N	N
TX	6139	Primary Ash Pond	Welsh	N	N	N	N	N	N	N	N	N	N	N	N
TX	6139	Secondary Ash Pond	Welsh	N	N	N	N	N	N	N	N	N	N	N	N
TX	6146	SPD-3	Martin Lake	N	Y	N	N	N	N	N	N	N	N	N	N
TX	6146	SPD-4	Martin Lake	N	Y	N	N	N	N	N	N	N	N	N	N
TX	6146	SPD-5	Martin Lake	N	Y	N	N	N	N	N	N	N	N	N	N
TX	6146	SPD-6	Martin Lake	N	Y	N	N	N	N	N	N	N	N	N	N
TX	6147	SPD-4	Monticello	N	N	Y	N	N	N	N	N	N	N	N	N
TX	6178	Primary Ash Pond	Coletto Creek	N	N	Y	N	N	N	N	N	N	N	N	N
TX	6178	Secondary Settling Pond	Coletto Creek	N	N	Y	N	N	N	N	N	N	N	N	N
TX	6179	Management Unit 002	Fayette Power Project	N	N	Y	N	N	N	N	N	N	N	N	N
TX	6179	Management Unit 009	Fayette Power Project	N	N	Y	N	N	N	N	N	N	N	N	N
TX	6180	SPD-2	Oak Grove Power Plant	N	N	Y	N	N	N	N	N	N	N	N	N
TX	6181	SPD-1	J T Deely	N	N	N	N	N	N	N	N	N	N	N	N
TX	6181	SPD-2	J T Deely	N	N	N	N	N	N	N	N	N	N	N	N
TX	6183	SPD-3	San Miguel	N	N	Y	N	N	N	N	N	N	N	N	N
TX	6183	SPD-4	San Miguel	N	N	Y	N	N	N	N	N	N	N	N	N
TX	6648	EPRI 8	Sandow No 4	N	N	N	N	N	Y	N	N	N	N	N	N
TX	7097	SPD-1	J K Spruce	N	Y	N	N	N	N	N	N	N	N	N	N
TX	7097	SPD-2	J K Spruce	N	Y	N	N	N	N	N	N	N	N	N	N
TX	7902	Auxilliary Surge Pond	Pirkey	N	N	N	N	N	N	N	N	N	N	N	N
TX	7902	East Bottom Ash Pond	Pirkey	N	N	N	N	N	N	N	N	N	N	N	N
TX	7902	Secondary Bottom Ash Pond	Pirkey	N	N	N	N	N	N	N	N	N	N	N	N
TX	7902	West Bottom Ash Pond	Pirkey	N	N	N	N	N	N	N	N	N	N	N	N
UT	3644	SPD-1	Carbon	N	N	N	N	N	N	N	N	N	N	N	N
UT	3644	SPD-2	Carbon	N	N	N	N	N	N	N	N	N	N	N	N
UT	6481	Ash Water Recycle	Intermountain Power Project	N	Y	N	N	N	N	N	N	N	N	N	N
UT	6481	Bottom Ash Basin	Intermountain Power Project	N	Y	N	N	N	N	N	N	N	N	N	N
UT	6481	Evaporation Ponds (6 Ponds)	Intermountain Power Project	N	Y	N	N	N	N	N	N	N	N	N	N
UT	6481	Land Fill Run-Off	Intermountain Power Project	N	Y	N	N	N	N	N	N	N	N	N	N
UT	6481	Settling Basin	Intermountain Power Project	N	Y	N	N	N	N	N	N	N	N	N	N
UT	6481	Wastewater Holding Basin	Intermountain Power Project	N	Y	N	N	N	N	N	N	N	N	N	N
UT	7790	SPD-3	Bonanza	N	N	N	N	N	N	N	N	N	N	N	N
UT	7790	SPD-5	Bonanza	N	N	N	N	N	N	N	N	N	N	N	N
UT	7790	SPD-6	Bonanza	N	N	N	N	N	N	N	N	N	N	N	N
UT	8069	SPD-4	Huntington	N	Y	N	N	N	N	N	N	N	N	N	N
VA	3775	Bottom Ash Pond 1A/1B	Clinch River	Y	N	N	N	N	N	N	N	N	N	N	N
VA	3776	Auxiliary Fly Ash Pond	Glen Lyn	Y	N	N	N	N	N	N	N	N	N	N	N
VA	3776	Bottom Ash Pond	Glen Lyn	Y	N	N	N	N	N	N	N	N	N	N	N

Exhibit H-4 List of Engineering Controls for Each of the 735 Surface Impoundments (Existing Units)															
State	Plant Code	Unit Name	Plant Name	Groundwater Monitoring	Liner					Lechate Collection System	Cap				PCM
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
VA	3796	North Ash Pond	Bremo Bluff	Y	N	N	N	N	N	N	N	N	N	N	N
VA	3796	West Ash Pond	Bremo Bluff	Y	N	N	N	N	N	N	N	N	N	N	N
VA	3797	Lower (Old) Ash Pond	Chesterfield	Y	N	N	N	N	N	N	N	N	N	N	N
VA	3797	Upper (New) Ash Pond	Chesterfield	Y	N	N	N	N	N	N	N	N	N	N	N
VA	3803	Bottom Ash/Sedimentation Pond	Chesapeake Energy Center	Y	N	N	N	N	N	N	N	N	N	N	N
VA	7213	SPD-2	Clover	Y	Y	N	N	N	N	N	N	N	N	N	N
VA	7213	SPD-3	Clover	Y	Y	N	N	N	N	N	N	N	N	N	N
VA	10771	SPD-1	Hopewell Power Station	Y	N	N	N	N	N	N	N	N	N	N	N
WI	3982	Polishing Pond	Bay Front	N	N	N	N	N	Y	N	N	N	N	N	N
WI	3982	Surge Basin	Bay Front	N	N	N	N	N	Y	N	N	N	N	N	N
WI	4050	A Ponds (Two)	Edgewater	N	N	N	N	N	Y	N	N	N	N	N	N
WI	4050	B Pond	Edgewater	N	N	N	N	N	Y	N	N	N	N	N	N
WI	4050	C Pond	Edgewater	N	N	N	N	N	Y	N	N	N	N	N	N
WI	4050	F Pond	Edgewater	N	N	N	N	N	Y	N	N	N	N	N	N
WI	4050	Slag Pond	Edgewater	N	N	N	N	N	Y	N	N	N	N	N	N
WI	4054	Slag Pond	Nelson Dewey	N	N	N	N	N	Y	N	N	N	N	N	N
WI	4057	Final WPDES Pond	WI Power & Light Co -Rock River Generating	N	N	N	N	N	Y	N	N	N	N	N	N
WI	4057	Slag Pond	WI Power & Light Co -Rock River Generating	N	N	N	N	N	Y	N	N	N	N	N	N
WI	4057	WPDES Pond 1	WI Power & Light Co -Rock River Generating	N	N	N	N	N	Y	N	N	N	N	N	N
WI	4057	WPDES Pond 2	WI Power & Light Co -Rock River Generating	N	N	N	N	N	Y	N	N	N	N	N	N
WI	4072	SPD-1	Pulliam	N	N	N	N	N	N	N	N	N	N	N	N
WI	4078	SPD-1	Weston	N	N	N	N	N	N	N	N	N	N	N	N
WI	4078	SPD-2	Weston	N	N	Y	N	N	N	N	N	N	N	N	N
WI	4078	SPD-3	Weston	N	N	Y	N	N	N	N	N	N	N	N	N
WI	4078	SPD-4	Weston	N	N	Y	N	N	N	N	N	N	N	N	N
WI	4078	SPD-5	Weston	N	N	Y	N	N	N	N	N	N	N	N	N
WI	4078	SPD-6	Weston	N	N	Y	N	N	N	N	N	N	N	N	N
WI	8023	Polishing Pond	Columbia	N	N	N	N	N	N	N	N	N	N	N	N
WI	8023	Primary Ash Pond	Columbia	N	N	N	N	N	N	N	N	N	N	N	N
WI	8023	Secondary Ash Pond	Columbia	N	N	N	N	N	N	N	N	N	N	N	N
WV	3935	Bottom Ash Complex	John E. Amos	N	N	N	N	N	N	N	N	N	N	N	N
WV	3935	Fly Ash Pond	John E. Amos	N	N	N	N	N	N	N	N	N	N	N	N
WV	3936	Bottom Ash Complex	Kanawha River	N	N	N	N	N	Y	N	N	N	N	N	N
WV	3938	Bottom Ash Pond	Philip Sporn	N	N	N	N	N	N	N	N	N	N	N	N
WV	3938	Unit 5 (Fly Ash Pond)	Philip Sporn	N	N	N	N	N	N	N	N	N	N	N	N
WV	3942	SPD-1	Albright	N	N	Y	N	N	N	N	N	N	N	N	N
WV	3942	SPD-2	Albright	N	N	Y	N	N	N	N	N	N	N	N	N
WV	3945	SPD-4	Rivesville	N	N	N	N	N	N	N	N	N	N	N	N
WV	3947	Boiler Slag Pond	Kammer	N	N	N	N	N	Y	N	N	N	N	N	N
WV	3948	Bottom Ash Complex	Mitchell	N	Y	N	N	N	N	N	N	N	N	N	N
WV	3948	Fly Ash Pond	Mitchell	N	N	N	N	N	Y	N	N	N	N	N	N
WV	6004	McElroy's Run Embankment	Pleasants Power Station	N	N	N	N	N	N	N	N	N	N	N	N
WV	6264	Bottom Ash Complex	Mountaineer	N	N	Y	N	N	N	N	N	N	N	N	N
WV	10151	SPD-3	Grant Town Power Plant	Y	N	N	N	N	N	Y	N	N	N	N	N
WV	10151	SPD-4	Grant Town Power Plant	Y	N	N	N	N	N	Y	N	N	N	N	N
WV	10151	SPD-7	Grant Town Power Plant	Y	N	N	N	N	N	Y	N	N	N	N	N
WV	10151	SPD-8	Grant Town Power Plant	Y	N	N	N	N	N	Y	N	N	N	N	N
WV	10151	SPD-9	Grant Town Power Plant	Y	N	N	N	N	N	Y	N	N	N	N	N
WY	4158	1A Clear Pond	Dave Johnston Plant	N	N	N	N	N	N	N	N	N	N	N	N
WY	4158	1B Ash Pond	Dave Johnston Plant	N	Y	N	N	N	N	N	N	N	N	N	N
WY	4158	1B Clear Pond	Dave Johnston Plant	N	N	N	N	N	N	N	N	N	N	N	N
WY	4158	4 Clear Pond	Dave Johnston Plant	N	N	N	N	N	N	N	N	N	N	N	N
WY	4158	4A Ash Pond	Dave Johnston Plant	N	Y	N	N	N	N	N	N	N	N	N	N

Exhibit H-4 List of Engineering Controls for Each of the 735 Surface Impoundments (Existing Units)															
State	Plant Code	Unit Name	Plant Name	Groundwater Monitoring	Liner					Lechate Collection System	Cap				PCM
					Synthetic	Clay	Ash	Yes	Unknown		Synthetic	Clay	Ash	Soil	
WY	4158	4B Ash Pond	Dave Johnston Plant	N	Y	N	N	N	N	N	N	N	N	N	N
WY	4162	FGD Pond #1	Naughton Plant	N	Y	N	N	N	N	N	N	N	N	N	N
WY	4162	FGD Pond #2	Naughton Plant	N	Y	N	N	N	N	N	N	N	N	N	N
WY	4162	North Ash Pond	Naughton Plant	N	N	N	N	N	N	N	N	N	N	N	N
WY	4162	South Ash Pond	Naughton Plant	N	N	N	N	N	N	N	N	N	N	N	N
WY	6101	Wyodak	Wyodak Plant	N	N	N	N	N	N	N	N	N	N	N	N
WY	6204	Bottom Ash Ponds 1 & 2 (BAP1 & BAP2)	Laramie River Station	N	Y	N	N	N	N	N	N	N	N	N	N
WY	6204	Emergency Holding Pond	Laramie River Station	N	Y	N	N	N	N	N	N	N	N	N	N
WY	8066	FGD Pond #2	Jim Bridger Plant Units 1-4	N	N	N	N	N	N	N	N	N	N	N	N

APPENDIX I

Note: This appendix was originally included for the RIA for the proposed CCR rule. The information and equation on the following pages remains accurate and properly reflects the underlying Fortran-based equations used in this RIA, with one exception:

- *While all cost equations presented in this appendix are in 2011\$, they have been inflated to 2013\$ using the Engineering News Record Construction Cost Index for use in this RIA.*

Construction & Debris Landfill Prices

State*	2006 Average Fee	2011 Average Fee per Ton**
AK	\$78	\$85.49
AL	\$24	\$26.30
AR	\$30	\$32.88
AZ	\$35	\$38.36
CA	\$46	\$50.42
CO	\$27	\$29.59
CT	\$86	\$94.26
DC	\$50.5	\$55.35
DE	\$59	\$64.66
FL	\$39	\$42.74
GA	\$30	\$32.88
HI	\$54	\$59.18
IA	\$38	\$41.65
ID	\$23	\$25.21
IL	\$43	\$47.13
IN	\$33	\$36.17
KS	\$25	\$27.40
KY	\$28	\$30.69
LA	\$25	\$27.40
MA	\$96	\$105.22
MD	\$57	\$62.47
ME	\$74	\$81.10
MI	\$47	\$51.51
MN	\$32	\$35.07
MO	\$41	\$44.94

State*	2006 Average Fee	2011 Average Fee per Ton**
MS	\$24	\$26.30
MT	\$43	\$47.13
NC	\$35	\$38.36
ND	\$19	\$20.82
NE	\$30	\$32.88
NH	\$91	\$99.74
NJ	\$76	\$83.30
NM	\$32	\$35.07
NV	\$23	\$25.21
NY	\$67	\$73.43
OH	\$32	\$35.07
OK	\$24	\$26.30
OR	\$46	\$50.42
PA	\$59	\$64.66
PR	-	\$48.84
RI	\$75	\$82.20
SC	\$30	\$32.88
SD	\$26	\$28.50
TN	\$30	\$32.88
TX	\$26	\$28.50
UT	\$22	\$24.11
VA	\$44	\$48.22
VT	\$129	\$141.38
WA	\$55	\$60.28
WI	\$40	\$43.84
WV	\$41	\$44.94
WY	\$33	\$36.17
Source: Offsite Disposal Unit Costs are from the Chartwell Solid Waste Group. 2007. Solid Waste Digest, Digest Year 17. Notes: * DC unit cost is comprised of the average of Virginia and Maryland. Puerto Rico is based on the average of all other states/territories. ** Calculated with a GDP Implicit Price Deflator Update Factor of 1.096.		
2006 Annual US Department of Commerce, Bureau of Economic Analysis, Implicit Price Deflator for Gross Domestic Product	103.231	
2011 Quarter II US Department of Commerce, Bureau of Economic Analysis, Implicit Price Deflator for Gross Domestic Product	113.094	

APPENDIX J

State Cost Adjustment Factors

State	State Cost Adjustment Factor*
AK	1.22
AL	0.806
AR	0.771
AZ	0.844
CA	1.07
CO	0.898
CT	1.086
DC	0.988
DE	1.039
FL	0.871
GA	0.822
HI	1.164
IA	0.817
ID	0.877
IL	1.039
IN	0.902
KS	0.828
KY	0.868
LA	0.817
MA	1.083
MD	0.854
ME	0.892
MI	0.937
MN	1.008
MO	0.905
MS	0.815

State	State Cost Adjustment Factor*
MT	0.878
NC	0.748
ND	0.814
NE	0.878
NH	0.85
NJ	1.099
NM	0.877
NV	0.943
NY	1.115
OH	0.92
OK	0.782
OR	0.969
PA	0.978
PR	0.785
RI	1.055
SC	0.778
SD	0.791
TN	0.817
TX	0.775
UT	0.832
VA	0.849
VT	0.827
WA	0.976
WI	0.953
WV	0.931
WY	0.805

*Source: *R.S. Means Building Construction Cost Data 2010*, 68th annual edition, pp. 737-741.

Average of all city location factors listed in each state.

APPENDIX K

Cost Estimates for Dust Controls

Landfills

Note: All costs presented in this section are in 2011\$ in accordance with the first creation of this appendix. All costs have been inflated to 2013\$ using the Engineering News Record Construction Cost Index for use in this RIA.

Compaction Equipment. Ash is assumed to be compacted in the waste management area by self-propelled rollers for regulatory scenarios including dust controls. A model cost assumption is that four passes are made by the roller in 6-inch lifts. With these assumptions, the roller can compact approximately 1,300 cy of ash per day. The operating life of purchased compaction equipment is assumed to be five years. The number of sheepsfoot rollers required is estimated as follows:

$$\text{Rollers} = (\text{tons/yr}) \times (2,000 \text{ lb/ton}) \times (16.02 \text{ kg/m}^3/\text{lb/cf}) \times (1,190 \text{ kg/m}^3) \times (27 \text{ cf/cy}) \times (1,300 \text{ cy/day}) \times (300 \text{ days/yr})$$

The cost of a sheepsfoot roller is assumed to be \$75,000 in 1995 dollars. Plants will incur annual costs for equipment operation (\$0.63/cy in 1995) and maintenance. Maintenance costs are assumed to be 5% of capital costs. Annual costs for compaction are estimated as follows:

$$\begin{aligned} \text{Annual Cost} = & [(\text{tons/yr}) \times (2,000 \text{ lb/ton}) \times (16.02 \text{ kg/m}^3/\text{lb/cf}) \times (\$0.63/\text{cy}) + \\ & \$75,000 \times 0.05 \times \text{Rollers} \times (1,190 \text{ kg/m}^3) \times (27 \text{ cf/cy})] \times (9053 \text{ June 2011 ENR} \\ & \text{Construction Cost Index} / 5471 \text{ 1995 ENR Construction Cost Index}) \end{aligned}$$

Water Truck for Compaction. Ash is assumed to be wetted in the waste management area by water trucks to facilitate compaction and to control dust. A model assumption is that plants currently use water trucks 50% of the operational day to control dust on roads (see Water Spray on Roads). It is reasonable to assume that the same water trucks will be used for the roads and the ash management unit. Therefore, it is assumed that an existing water truck is available for compaction 50% of the operational day. Additional water trucks are assumed to be necessary to facilitate compaction for large facilities. The cost of tarps, tarp mechanisms, and installation of the mechanisms, as well as the life of each tarp were estimated by ICF in “Cost Functions for Alternative CKD Control Technologies” (Draft), 19 July 1996. A model assumption is that a water truck will be necessary for compaction 50% of the time required by the compaction equipment. The water truck time for compaction is estimated as follows:

$$\text{Water Truck Time for Compaction} = (\text{tons/yr}) \times (2,000 \text{ lb/ton}) \times (16.02 \text{ kg/m}^3/\text{lb/cf}) \times (8 \text{ hr/day}) \times (0.5) \times (1,190 \text{ kg/m}^3) \times (27 \text{ cf/cy}) \times (1,300 \text{ cy/day})$$

One existing water truck for compaction and water spray on roads is estimated to be sufficient for plants managing less than 391,000 tons per year of ash. Facilities managing between 391,000 and 1,173,000 tons per year are assumed to purchase one additional water truck. Facilities managing between 1,173,000 and 1,955,000 tons per year are assumed to purchase two additional water trucks. Facilities managing more than 1,955,000 tons per year to the maximum facility size modeled of 2,000,000 tons per year are assumed to purchase three additional water trucks.

The cost of a water truck is assumed to be \$101,000 in 1995 dollars. The water truck operating life is assumed to be five years. The operating costs for water spray for compaction are estimated assuming that the truck travels approximately five miles per day, for each day used, with a fuel consumption of five miles per gallon at a fuel cost of \$1.15 per gallon. The truck is assumed to operate 50% of the hours required for compaction. The daily water volume used is assumed to be 10,000 gallons, at a cost of \$2 per 1,000 gallons. The annual cost associated with ash management is estimated as follows:

$$\text{Annual Cost} = (\text{tons/yr}) \times (2,000 \text{ lb/MT}) \times (16.02 \text{ kg/m}^3/\text{lb/cf}) \times (0.5) \times [(8\text{hr/day}) \times (\$31.50/\text{hr}) \times (1,190 \text{ kg/m}^3) \times (27 \text{ cf/cy}) \times (1,300 \text{ cy/day}) + (5 \text{ mi/day}) \times (\$1.15/\text{gal}) / (5 \text{ mi/gal}) + (10,000 \text{ gal/day}) \times (\$2/1,000 \text{ gal})] \times (9053 \text{ June 2011 ENR Construction Cost Index} / 5471 \text{ 1995 ENR Construction Cost Index})$$

Covers on Trucks. Covers on hauling trucks as a fugitive dust control technology is an option for the compliance scenarios. Capital costs for this dust control technology include the cost of the roll-on tarp mechanism and the installation of this mechanism. Capital costs for covers on trucks are estimated as follows:

$$\text{Capital Cost} = [(\text{tons/year}) \times (2,000 \text{ lb/ton}) \times (16.02 \text{ kg/m}^3/\text{lb/cf}) \times (0.65 \text{ hr/load})] \times (\$4,800) \times (9053 \text{ June 2011 ENR Construction Cost Index} / 5471 \text{ 1995 ENR Construction Cost Index})$$

Annual costs for this dust control technology include the cost of the tarps and the cost to replace the tarps. Tarps are estimated to be replaced every 150 loads. Replacement of a tarp is estimated to require 15 minutes. Annual costs for covers on trucks are estimated as follows:

$$\text{Annual Cost} = (\text{tons/yr}) \times (2,000 \text{ lb/ton}) \times (16.02 \text{ kg/m}^3/\text{lb/cf}) \times (\$155/\text{tarp} + 0.25\text{hr/tarp} \times \$19/\text{hr}) \times (1,190 \text{ kg/m}^3) \times (0.80) \times (27 \text{ cf/cy}) \times (9 \text{ cy/load}) \times (150 \text{ load/tarp}) \times (9053 \text{ June 2011 ENR Construction Cost Index} / 5471 \text{ 1995 ENR Construction Cost Index})$$

Water Spray on Roads. Water spray on roads is required as a fugitive dust control technology for the compliance scenarios. A model assumption is that plants currently have water trucks and use water spray on roads as a baseline management practice. A model assumption is that dust control is required for a road length of 1.5 miles (3 miles round trip), with a road width of 10 meters. The water truck capacity is assumed to be 5,000 gallons and requires approximately one hour to fill. The water truck can spray a width of five meters at an assumed speed of 10 miles per hour.

For the baseline scenario, a model assumption is that the entire water volume (5,000 gallons) will be sprayed on each pass of the truck along one side of the road (i.e., 1.5 miles x 5 meters).¹ The resulting water volume per road area, averaged over the 1.25 hours required to spray the road and refill the truck, is approximately 2.5 times that of the average hourly daytime evaporation rate. Therefore, water spray on roads will be required 3 times per day. The water volume sprayed per road area is estimated as follows:

$$\text{Water per Area} = (1.5 \text{ mi}) \times (5,280 \text{ ft/mi}) \times (0.3048 \text{ m/ft}) \times (10 \text{ m}) \times (5,000 \text{ gal}) / (3.785 \text{ L/gal}) = 0.784 \text{ L/m}^2$$

The time required for the water truck to be filled, spray along both sides of the road, and return for refilling is estimated as follows:

$$\text{Time} = (1 \text{ hour}) + (3 \text{ miles}) / (10 \text{ miles/hour}) = 1.3 \text{ hour}$$

Therefore, the total time for one pass is assumed to be 1 hour and 15 minutes. The average rate of water spray is estimated as follows:

$$\text{Spray Rate} = (0.784 \text{ L/m}^2) \times (1,000 \text{ ml/L}) \times (1 \text{ cm}^3/\text{ml}) \times (1,000 \text{ mm/m}) = (0.6272 \text{ mm/hr}) \times (100 \text{ cm/m})^3 \times (1.25 \text{ hr})$$

The average hourly daytime evaporation rate is approximately 0.25 mm/hr. Therefore, the water spray rate is approximately 2.5 times the evaporation rate. Since the total time required for water spray (1.25 hour) times 2.5 is approximately 3, a model assumption is that water spray on roads is required approximately every 3 hours. In order to coordinate the water truck use for road spray and ash compaction, it is assumed that the truck alternates between these two requirements during the day. Therefore, over a nine-hour day (eight working hours plus one hour for lunch), roads are sprayed 3 times, requiring a total of approximately 4 hours, or 50% of the operational day. Because it is assumed that coal-fired electrical generating plants currently spray water on roads for dust control, the incremental cost from the baseline to the compliance scenarios is zero.

For additional information on the integration of dust controls for landfills in this RIA under both the baseline and CCR final rule scenarios, see **Chapters 3 and 4** of this RIA.

Surface Impoundments

For information on the costs associated with dust controls used in this RIA, see **Section 4.3.5.2**. The key information from that section is provided below for completeness.

This RIA assumes that dust control for surface impoundments is not required under any state regulatory baseline; correspondingly, dust control costs resulting from the CCR final rule are fully incremental. This RIA estimates dust control costs for impoundments as follows, noting

¹ Water truck capacity, refill time, and spray width were estimated by ICF in “Cost Functions for Alternative CKD Control Technologies” (Draft), dated July 19, 1996.

that it includes a number of dust control technologies as a conservative estimate in order to avoid underestimating costs associated with dust controls (all costs below in 2013\$):

- \$30,688 per acre for topsoil and seeding, annualized over 40 years as an assumed lifespan;
- \$944 per day for a water spray truck, applied only for half the days in a given year based on the assumption that water spraying is not required daily;
- \$2,700 per acre for a long-term Posi-Shell treatment assumed to last for one year;
- \$1,000 per week for a stationary sprayer (dust boss); and
- \$1,600 per acre for soil “sement,” applied semiannually.

In general, however, this RIA assumes that for surface impoundments, ash is sluiced from the boiler or air pollution control device to the pond, and never handled as “dry” ash. This RIA also assumes that all surface impoundment units undergo closure as landfills, meaning that surface impoundments are not excavated, nor is their ash trucked off-site. In summary, dust controls are generally unnecessary for surface impoundment units, except in cases where frozen wet ash (due to low temperatures) combines with high wind speeds to lead to fugitive dust associated with frozen wet ash from surface impoundments.²

In order to scale down the dust control costs given that dust controls may not be needed in most cases, this RIA collected historical data on the number of freezing, high-wind days in each state; on average, states have experienced fewer than two freezing, high-wind days a year. For each surface impoundment, this RIA scales down the dust control costs above by the number of freezing, high-wind days in the state in which the impoundment is located. As a result, these scaled-down annual costs for dust controls for surface impoundments are relatively low and average no more than \$3,000 per year, depending on impoundment acreage and the state.³ These costs are consistent with assumptions regarding the need for dust controls at impoundments and the associated dust control costs for landfills, which are approximately \$30,000 per year.

Exhibit K-1 below indicates the number of freezing, high-wind days for each state, as well as the proportion of days in a year meeting these criteria. For six states and territories with coal-fired electric utility plants (AK, HI, PR, WV, WI, WY), data on freezing, high-wind days were not available; this RIA uses the average across all other states and territories as a proxy. This results in a slight overestimate for certain areas unlikely to have freezing, high-wind days (Hawaii and Puerto Rico) but may be an underestimate for Wyoming, Wisconsin, and Alaska.

² Some very large surface impoundments or impoundments in dry, desert-like areas may also have portions of their CCR and/or periods of time when their contents may become dry enough to require dust controls. We use the frozen, high-wind days scenario as a proxy for these cases as well.

³ In cases where impoundment acreage was not available from the impoundment identification and survey data discussed in **Chapter 2**, this RIA applied equations based on average impoundment dimensions if other dimensions (e.g., impoundment capacity, impoundment depth, etc.) were available. In cases where no impoundment dimension data were available, this RIA maps each impoundment to the average acreage among all impoundments.

Exhibit K-1		
Dust Control Scaling Factors		
State	Freezing, High-Wind Days	% of Freezing, High-Wind Days per Year
AL	0.944	0.258%
AK	1.990*	0.545%
AZ	6.186	1.694%
AR	0.787	0.216%
CA	1.173	0.321%
CO	3.939	1.078%
CT	1.769	0.484%
DE	3.100	0.849%
DC	0.357	0.098%
FL	0.091	0.025%
GA	0.821	0.225%
HI	1.990*	0.545%
ID	2.714	0.743%
IL	1.820	0.498%
IN	1.553	0.425%
IA	0.680	0.186%
KS	1.779	0.487%
KY	1.588	0.435%
LA	0.147	0.040%
ME	2.585	0.708%
MD	2.394	0.655%
MA	2.691	0.737%
MI	2.293	0.628%
MN	1.272	0.348%
MS	0.939	0.257%
MO	1.099	0.301%
MT	5.145	1.409%
NE	1.325	0.363%
NV	5.939	1.626%
NH	3.097	0.848%
NJ	1.315	0.360%
NM	2.710	0.742%
NY	2.130	0.583%
NC	1.512	0.414%
ND	1.168	0.320%
OH	1.462	0.400%
OK	0.513	0.140%
OR	2.808	0.769%

Exhibit K-1		
Dust Control Scaling Factors		
State	Freezing, High-Wind Days	% of Freezing, High-Wind Days per Year
PA	2.382	0.652%
PR	1.990*	0.545%
RI	2.056	0.563%
SC	0.599	0.164%
SD	0.376	0.103%
TN	1.313	0.360%
TX	0.959	0.262%
UT	5.124	1.403%
VT	2.708	0.741%
VA	1.774	0.486%
WA	2.405	0.658%
WV	1.990*	0.545%
WI	1.990*	0.545%
WY	1.990*	0.545%
Notes: * No data were available for the number of freezing, high-wind days for these states and territories. The average number of freezing, high-wind days among all states and territories with available data was assigned to these states and territories. Count of freezing, high-wind days calculated by first calculating an average annual count of freezing days by state from NOAA National Weather Data (the number of freezing days across all locations in a state were averaged to create one statewide figure) and then multiplying this count by the average proportion of annual high-wind days as obtained from the NOAA National Climatic Data Center Storm Events Database, querying for both “high winds” and “strong winds.” The proportion of freezing, high-wind days in a given state in a given year calculated by dividing the annual number of freezing, high-wind days by 365.25, the average number of days in a given year.		

Lastly, this appendix presents three historical cases of fugitive dust from CCR surface impoundments during subfreezing temperatures below.

Three Documented Historical “Notice of Violation” Cases (1993 & 2009) of CCR Fugitive Dust Emitted from Surface Impoundments During Subfreezing Temperatures

First Energy’s Bruce Mansfield, Shippingport, PA:

References: Lisa Evans email, 5/18/2011; PADEP’s comment to the 2011 NODA

- **CASE #1 of 3:** PA DEP has issued several NOV’s for GW contamination and fugitive dust; the earliest NOV on hand is a March 8, 1993 PA Air Quality Control/DENR letter to the Bruce Mansfield Power Company indicating violations of Sections 6.1 (a), 6.1(b) and 8 of the Air Pollution Control Act, and violations of 25 Pa Code §§123.1(a) and 123.2, that have occurred in the LBR impoundment, between 1/30 and 2/4/1993. Subfreezing temperatures combined with strong winds lifted up CCRs (gypsum, lime,

limestone, and possibly, calcium sulfite) from an elevated bar in the LBR, generating heavy dust clouds that settled on adjacent properties, barns and range areas. It lead state and local officials to issue an air advisory for Greene Township and Hookstown. The advisory recommended that people stay indoors, especially those with respiratory problems, and those that have to be outdoors, protect themselves with a mask to avoid breathing in the dust. The PP responded by raising the water levels in the SI and by spraying a dust-inhibiting chemical on the sludge. The Company also said it is willing to provide lodging or other assistance for affected residents.

- Analyses of the exposed CCRs collected on 2/2/1993 from the surface of the SI, yielded, among others (in PPMs) As: 18; Cr: 33; Pb: 3.2; Ni: 18; and Se: 1.5.
- **CASE #2 of 3:** On 3/12/2009, Waste Management SW Region/DENR issued another NOV alleging violation, on 3/4/2009, of §§ 289.271(a)(7); and the Solid Waste Management Act, July 7, 1980, P.L. 380, as amended, 35 P.S. §§ 6018.101-6018.1003, for a repeat of the 1993 dust dispersion event under similar circumstances (subfreezing temperatures combined with high winds, resulting in settling of significant amounts of CCRs on the ground, houses/lawns/decks, and automobiles). First Energy applied wetting of the SI and latex soil cementing agent for mitigation/control. A \$24,500 penalty was paid. In addition, DEP required a modification of the permit requiring more frequent inspections by FirstEnergy to reduce dusting potential.
- “In 2009, dry conditions on the surface of the impoundment covered nearby residents’ homes in a layer of coal ash fugitive dust, prompting an NOV”. First Energy notified DEP of a potential dusting problem at the impoundment and initiated actions to quickly address the dusting. DEP immediately responded by issuing an NOV, assessing a civil penalty and mandating that corrective actions be taken. DEP required First Energy to modify its permitted nuisance control plan and submit regular documentation on inspections and corrective actions to reduce dusting potential. FirstEnergy responded to the NOV and corrected the situation (PADEP’s comment to the 2011 NODA docket, #2011-0392-0201⁴).

Progress Energy, Asheville (Arden), NC

References: Charlotte public hearing, cited in *Out of Control* (2/2010), in ICF’s report (10/2010) as Potential DC; two consecutive emails by Lisa Evans on 5/19/2011, and one - on 5/21/2011.

- **CASE #3 of 3:** Coal ash from waste disposal blowing and covering houses, garages and cars/
- NC’s Division of Water Quality issued (1/22/2009) a NOV of Permit WQ0000020 for failing to take adequate provisions to prevent wind erosion and surface runoff from conveying ash from stockpile/storage areas onto adjacent property or into any surface waters. This resulted in the deposition of ash on property adjacent to Progress Energy’s

⁴ Commonwealth of Pennsylvania Department of Environmental Protection Southwest Region: Review of the Environmental Integrity Project, Earthjustice and Sierra Club Report: In Harm’s Way: Lack of Federal Coal Ash Regulations Endangers Americans and Their Environment, Thirty-nine New Damage Cases of Contamination, From Improperly Disposed Coal Combustion Waste August 26, 2010; Page 26.

ash storage pond: ash from the ash pond had blown and accumulated on several properties (homes, cars and lawns) in the Lake Julian Trails housing development.

- According to Progress Energy's response letter (2/9/2009), the source area is an NPDES permitted SI rather than a stockpile area, hence no permit conditions are violated. The fugitive dust comprises cenospheres that in spite of the application of dust suppressing measures (mulch with dust suppressant, straw and wetting) become airborne during extended periods of winter subfreezing temperatures, when their harvesting from the top of the frozen pond is halted. In response to the NOV, Progress Energy stated that they are evaluating the establishment of an alternate harvesting area that has more wind buffer, as well as wind break options at the existing harvesting area.
- One of the neighboring residents stated that after one bad incident Progress Energy washed everyone's house and had someone specially vacuum people's homes.
- The same neighbor also stated that there was little or no enforcement, until the community started pushing someone to do something about it. They finally were able to get their state aquifer protection branch to issue an NOV. They are supposed to be putting up an air monitoring system and coming up with a plan to reduce dust. They already came up with one plan to spray more and planted trees and shrubs for additional buffering.

APPENDIX L

Location Restriction Data

Note: EPA has updated the universe to reflect 61 actual and projected plant retirements occurring after 2012 according to the National Electric Energy Data System (NEEDS) v.5.13 dataset; see **Section 9.2.1** in **Chapter 9** for a description of the relevant updates. Exhibits in this appendix have not been updated to reflect the revisions described in **Section 9.2.1**.

Exhibit L-1: Fault Line Data Listed by Plant

Exhibit L-2: Seismic Impact Data Listed by Plant

Exhibit L-3: Karst Data Listed by Plant

Exhibit L-1: Fault Line Data Listed by Plant

Plant ID	Plant Name	Nearest Fault	Distance (miles)	Age	Fault Type
3	Barry	Meers fault, southeastern section	622.63244	<15,000	Well constrained
7	Gadsden	Meers fault, southeastern section	668.32655	<15,000	Well constrained
8	Gorgas	Meers fault, southeastern section	606.15862	<15,000	Well constrained
10	Greene County	Meers fault, southeastern section	592.43558	<15,000	Well constrained
26	E C Gaston	Meers fault, southeastern section	651.64380	<15,000	Well constrained
47	Colbert	Meers fault, southeastern section	562.21898	<15,000	Well constrained
50	Widows Creek	Meers fault, southeastern section	674.23647	<15,000	Well constrained
51	Dolet Hills	Meers fault, southeastern section	318.25391	<15,000	Well constrained
56	Charles R Lowman	Meers fault, southeastern section	613.23402	<15,000	Well constrained
59	Platte	Crooked Creek fault (Class B)	250.03997	Class B	Well constrained
60	Whelan Energy Center	Crooked Creek fault (Class B)	233.37179	Class B	Well constrained
79	Aurora Energy LLC Chena	Unnamed faults in Strait of Juan de Fuca and Puget Sound (Class B)	1410.16375	Class B	Well constrained
87	Escalante	Unnamed fault of Bonita Canyon (Class B)	29.42116	Class B	Moderately constrained
108	Holcomb	Crooked Creek fault (Class B)	52.23891	Class B	Well constrained
113	Cholla	Vernon fault zone	46.70579	<750,000	Well constrained
126	H Wilson Sundt Generating Station	Santa Rita fault zone	15.00701	<130,000	Moderately constrained
127	Oklaunion	Meers fault, northwestern section	59.99028	<1,600,000	Well constrained
130	Cross	Meers fault, southeastern section	991.42698	<15,000	Well constrained
136	Seminole	Meers fault, southeastern section	988.54267	<15,000	Well constrained
160	Apache Station	North Swisshelm fault	23.24815	<1,600,000	Inferred
165	GRDA	Meers fault, southeastern section	189.75369	<15,000	Well constrained
207	St Johns River Power Park	Meers fault, southeastern section	973.22438	<15,000	Well constrained
298	Limestone	Meers fault, southeastern section	252.93844	<15,000	Well constrained
384	Joliet 29	Crooked Creek fault (Class B)	664.53864	Class B	Well constrained
462	W N Clark	Ute Pass fault zone	25.13771	<750,000	Well constrained
465	Arapahoe	Golden fault (Class B)	6.96190	Class B	Inferred
469	Cherokee	Walnut Creek fault (Class B)	12.39378	Class B	Moderately constrained
470	Comanche	Goodpasture fault	20.46758	<1,600,000	Well constrained
477	Valmont	Valmont fault (Class B)	0.83768	Class B	Well constrained
492	Martin Drake	Rampart Range fault	2.31728	<750,000	Well constrained
508	Lamar Plant ^(k)	Cheraw fault	210.05195	<15,000	Well constrained
525	Hayden	Killarney faults	22.10969	<1,600,000	Well constrained
527	Nucla	Paradox Valley graben (Class B)	4.91641	Class B	Well constrained
564	Stanton Energy Center	Meers fault, southeastern section	1052.20269	<15,000	Well constrained
568	Bridgeport Station	Meers fault, southeastern section	1360.71750	<15,000	Well constrained
594	Indian River Generating Station	Meers fault, southeastern section	1234.02042	<15,000	Well constrained
602	Brandon Shores	Meers fault, southeastern section	1173.12483	<15,000	Well constrained
628	Crystal River	Meers fault, southeastern section	958.18049	<15,000	Well constrained
641	Crist	Meers fault, southeastern section	676.36986	<15,000	Well constrained
642	Scholz	Meers fault, southeastern section	792.40369	<15,000	Well constrained
643	Lansing Smith	Meers fault, southeastern section	762.84973	<15,000	Well constrained
645	Big Bend	Meers fault, southeastern section	1014.47962	<15,000	Well constrained
663	Deerhaven Generating Station	Meers fault, southeastern section	948.60980	<15,000	Well constrained
667	Northside Generating Station	Meers fault, southeastern section	973.22925	<15,000	Well constrained
676	C D McIntosh Jr	Meers fault, southeastern section	1027.85726	<15,000	Well constrained
703	Bowen	Meers fault, southeastern section	723.94099	<15,000	Well constrained
708	Hammond	Meers fault, southeastern section	699.89228	<15,000	Well constrained
709	Harlee Branch	Meers fault, southeastern section	822.11455	<15,000	Well constrained
710	Jack McDonough	Meers fault, southeastern section	750.84212	<15,000	Well constrained

Exhibit L-1: Fault Line Data Listed by Plant

Plant ID	Plant Name	Nearest Fault	Distance (miles)	Age	Fault Type
727	Mitchell	Meers fault, southeastern section	811.15463	<15,000	Well constrained
728	Yates	Meers fault, southeastern section	732.34821	<15,000	Well constrained
733	Kraft	Meers fault, southeastern section	955.41239	<15,000	Well constrained
753	Crisp Plant	Meers fault, southeastern section	812.20996	<15,000	Well constrained
856	E D Edwards	Crooked Creek fault (Class B)	572.50296	Class B	Well constrained
861	Coffeen	Meers fault, southeastern section	552.25205	<15,000	Well constrained
867	Crawford	Crooked Creek fault (Class B)	691.06048	Class B	Well constrained
874	Joliet 9	Crooked Creek fault (Class B)	664.94157	Class B	Well constrained
876	Kincaid Generation LLC	Crooked Creek fault (Class B)	562.35277	Class B	Well constrained
879	Powerton	Crooked Creek fault (Class B)	570.56987	Class B	Well constrained
883	Waukegan	Crooked Creek fault (Class B)	702.24265	Class B	Well constrained
884	Will County	Crooked Creek fault (Class B)	670.84120	Class B	Well constrained
886	Fisk Street	Crooked Creek fault (Class B)	694.81398	Class B	Well constrained
887	Joppa Steam	Meers fault, southeastern section	527.78986	<15,000	Well constrained
889	Baldwin Energy Complex	Meers fault, southeastern section	504.30689	<15,000	Well constrained
891	Havana	Crooked Creek fault (Class B)	546.21182	Class B	Well constrained
892	Hennepin Power Station	Crooked Creek fault (Class B)	605.64850	Class B	Well constrained
898	Wood River	Meers fault, southeastern section	513.61406	<15,000	Well constrained
963	Dallman	Crooked Creek fault (Class B)	559.65699	Class B	Well constrained
976	Marion	Meers fault, southeastern section	531.69345	<15,000	Well constrained
981	State Line Energy	Crooked Creek fault (Class B)	697.18488	Class B	Well constrained
983	Clifty Creek	Meers fault, southeastern section	728.07978	<15,000	Well constrained
988	Tanners Creek	Meers fault, southeastern section	762.63958	<15,000	Well constrained
990	Harding Street	Meers fault, southeastern section	716.27185	<15,000	Well constrained
991	Eagle Valley	Meers fault, southeastern section	699.68751	<15,000	Well constrained
992	CC Perry K	Meers fault, southeastern section	719.14827	<15,000	Well constrained
994	AES Petersburg	Meers fault, southeastern section	635.25631	<15,000	Well constrained
995	Bailly	Crooked Creek fault (Class B)	713.88788	Class B	Well constrained
997	Michigan City	Crooked Creek fault (Class B)	725.41129	Class B	Well constrained
1001	Cayuga	Meers fault, southeastern section	668.08015	<15,000	Well constrained
1004	Edwardsport	Meers fault, southeastern section	642.65987	<15,000	Well constrained
1008	R Gallagher	Meers fault, southeastern section	697.87688	<15,000	Well constrained
1010	Wabash River	Meers fault, southeastern section	655.42224	<15,000	Well constrained
1012	F B Culley	Meers fault, southeastern section	617.68327	<15,000	Well constrained
1024	Crawfordsville	Meers fault, southeastern section	695.33051	<15,000	Well constrained
1032	Logansport	Crooked Creek fault (Class B)	730.76184	Class B	Well constrained
1037	Peru	Crooked Creek fault (Class B)	746.76046	Class B	Well constrained
1040	Whitewater Valley	Meers fault, southeastern section	778.48449	<15,000	Well constrained
1043	Frank E Ratts	Meers fault, southeastern section	634.42949	<15,000	Well constrained
1046	Dubuque	Crooked Creek fault (Class B)	586.56821	Class B	Well constrained
1047	Lansing	Crooked Creek fault (Class B)	601.04980	Class B	Well constrained
1048	Milton L Kapp	Crooked Creek fault (Class B)	579.90784	Class B	Well constrained
1073	Prairie Creek	Crooked Creek fault (Class B)	525.70411	Class B	Well constrained
1077	Sutherland	Crooked Creek fault (Class B)	482.03759	Class B	Well constrained
1081	Riverside	Crooked Creek fault (Class B)	562.15382	Class B	Well constrained
1082	Walter Scott Jr Energy Center	Crooked Creek fault (Class B)	335.24886	Class B	Well constrained
1091	George Neal North	Crooked Creek fault (Class B)	383.71158	Class B	Well constrained
1104	Burlington	Crooked Creek fault (Class B)	509.06104	Class B	Well constrained
1122	Ames Electric Services Power Plant	Crooked Creek fault (Class B)	453.45854	Class B	Well constrained
1131	Streeter Station	Crooked Creek fault (Class B)	518.72096	Class B	Well constrained
1167	Muscatine Plant #1	Crooked Creek fault (Class B)	531.05864	Class B	Well constrained

Exhibit L-1: Fault Line Data Listed by Plant

Plant ID	Plant Name	Nearest Fault	Distance (miles)	Age	Fault Type
1175	Pella	Crooked Creek fault (Class B)	453.45198	Class B	Well constrained
1217	Earl F Wisdom	Crooked Creek fault (Class B)	461.11394	Class B	Well constrained
1239	Riverton	Meers fault, southeastern section	250.37875	<15,000	Well constrained
1241	La Cygne	Crooked Creek fault (Class B)	289.89191	Class B	Well constrained
1250	Lawrence Energy Center	Crooked Creek fault (Class B)	271.60660	Class B	Well constrained
1252	Tecumseh Energy Center	Crooked Creek fault (Class B)	258.72530	Class B	Well constrained
1295	Quindaro	Crooked Creek fault (Class B)	304.72508	Class B	Well constrained
1353	Big Sandy	Meers fault, southeastern section	856.56813	<15,000	Well constrained
1355	E W Brown	Meers fault, southeastern section	745.70509	<15,000	Well constrained
1356	Ghent	Meers fault, southeastern section	746.89686	<15,000	Well constrained
1357	Green River	Meers fault, southeastern section	617.80508	<15,000	Well constrained
1361	Tyrone	Meers fault, southeastern section	742.98468	<15,000	Well constrained
1363	Cane Run	Meers fault, southeastern section	693.78277	<15,000	Well constrained
1364	Mill Creek	Meers fault, southeastern section	690.31751	<15,000	Well constrained
1374	Elmer Smith	Meers fault, southeastern section	628.56960	<15,000	Well constrained
1378	Paradise	Meers fault, southeastern section	623.41575	<15,000	Well constrained
1379	Shawnee	Meers fault, southeastern section	530.97807	<15,000	Well constrained
1381	Kenneth C Coleman	Meers fault, southeastern section	645.06190	<15,000	Well constrained
1382	HMP&L Station Two Henderson	Meers fault, southeastern section	603.75478	<15,000	Well constrained
1383	Robert A Reid	Meers fault, southeastern section	603.72037	<15,000	Well constrained
1384	Cooper	Meers fault, southeastern section	742.43645	<15,000	Well constrained
1385	Dale	Meers fault, southeastern section	769.72506	<15,000	Well constrained
1393	R S Nelson	Meers fault, southeastern section	412.36527	<15,000	Well constrained
1552	C P Crane	Meers fault, southeastern section	1183.26394	<15,000	Well constrained
1554	Herbert A Wagner	Meers fault, southeastern section	1173.68864	<15,000	Well constrained
1570	FirstEnergy R Paul Smith Power Station	Meers fault, southeastern section	1113.98003	<15,000	Well constrained
1571	Chalk Point LLC	Meers fault, southeastern section	1160.14759	<15,000	Well constrained
1572	Dickerson	Meers fault, southeastern section	1127.22756	<15,000	Well constrained
1573	Morgantown Generating Plant	Meers fault, southeastern section	1144.04292	<15,000	Well constrained
1606	Mount Tom	Meers fault, southeastern section	1404.52197	<15,000	Well constrained
1619	Brayton Point	Meers fault, southeastern section	1463.24207	<15,000	Well constrained
1626	Salem Harbor	Meers fault, southeastern section	1489.21837	<15,000	Well constrained
1695	B C Cobb	Crooked Creek fault (Class B)	795.72570	Class B	Well constrained
1702	Dan E Karn	Crooked Creek fault (Class B)	910.29687	Class B	Well constrained
1710	J H Campbell	Crooked Creek fault (Class B)	787.43467	Class B	Well constrained
1720	J C Weadock	Crooked Creek fault (Class B)	910.27573	Class B	Well constrained
1723	J R Whiting	Crooked Creek fault (Class B)	887.65949	Class B	Well constrained
1731	Harbor Beach	Crooked Creek fault (Class B)	967.86985	Class B	Well constrained
1733	Monroe	Crooked Creek fault (Class B)	894.18555	Class B	Well constrained
1740	River Rouge	Crooked Creek fault (Class B)	911.93183	Class B	Well constrained
1743	St Clair	Crooked Creek fault (Class B)	950.92417	Class B	Well constrained
1745	Trenton Channel	Crooked Creek fault (Class B)	906.00768	Class B	Well constrained
1769	Presque Isle	Brockton-Froid fault zone (Class B)	761.62726	Class B	Well constrained
1771	Escanaba	Brockton-Froid fault zone (Class B)	791.95980	Class B	Well constrained
1825	J B Sims	Crooked Creek fault (Class B)	790.63522	Class B	Well constrained
1830	James De Young	Crooked Creek fault (Class B)	788.21814	Class B	Well constrained
1831	Eckert Station	Crooked Creek fault (Class B)	855.33859	Class B	Well constrained
1832	Erickson Station	Crooked Creek fault (Class B)	850.28454	Class B	Well constrained
1843	Shiras	Brockton-Froid fault zone (Class B)	762.61610	Class B	Well constrained
1866	Wyandotte	Crooked Creek fault (Class B)	909.24686	Class B	Well constrained

Exhibit L-1: Fault Line Data Listed by Plant

Plant ID	Plant Name	Nearest Fault	Distance (miles)	Age	Fault Type
1891	Syl Laskin	Brockton-Froid fault zone (Class B)	540.23995	Class B	Well constrained
1893	Clay Boswell	Brockton-Froid fault zone (Class B)	479.22711	Class B	Well constrained
1897	M L Hibbard	Brockton-Froid fault zone (Class B)	552.94264	Class B	Well constrained
1904	Black Dog	Brockton-Froid fault zone (Class B)	558.35478	Class B	Well constrained
1915	Allen S King	Brockton-Froid fault zone (Class B)	570.17982	Class B	Well constrained
1943	Hoot Lake	Brockton-Froid fault zone (Class B)	398.36307	Class B	Well constrained
1961	Austin Northeast	Crooked Creek fault (Class B)	557.10037	Class B	Well constrained
1979	Hibbing	Brockton-Froid fault zone (Class B)	507.89757	Class B	Well constrained
2008	Silver Lake	Crooked Creek fault (Class B)	589.66762	Class B	Well constrained
2018	Virginia	Brockton-Froid fault zone (Class B)	523.83323	Class B	Well constrained
2022	Willmar	Brockton-Froid fault zone (Class B)	475.75498	Class B	Well constrained
2049	Jack Watson	Meers fault, southeastern section	592.12185	<15,000	Well constrained
2062	Henderson	Meers fault, southeastern section	446.64036	<15,000	Well constrained
2076	Asbury	Meers fault, southeastern section	267.53451	<15,000	Well constrained
2079	Hawthorn	Crooked Creek fault (Class B)	312.23593	Class B	Well constrained
2080	Montrose	Crooked Creek fault (Class B)	325.41194	Class B	Well constrained
2094	Sibley	Crooked Creek fault (Class B)	327.00721	Class B	Well constrained
2098	Lake Road	Crooked Creek fault (Class B)	310.21941	Class B	Well constrained
2103	Labadie	Meers fault, southeastern section	472.09370	<15,000	Well constrained
2104	Meramec	Meers fault, southeastern section	488.68234	<15,000	Well constrained
2107	Sioux	Meers fault, southeastern section	508.62958	<15,000	Well constrained
2123	Columbia	Crooked Creek fault (Class B)	414.32421	Class B	Well constrained
2132	Blue Valley	Crooked Creek fault (Class B)	318.39893	Class B	Well constrained
2144	Marshall	Crooked Creek fault (Class B)	373.11338	Class B	Well constrained
2161	James River Power Station	Meers fault, southeastern section	313.54409	<15,000	Well constrained
2167	New Madrid	Meers fault, southeastern section	480.51515	<15,000	Well constrained
2168	Thomas Hill	Crooked Creek fault (Class B)	409.09017	Class B	Well constrained
2169	Chamois	Meers fault, southeastern section	438.27306	<15,000	Well constrained
2171	Missouri City	Crooked Creek fault (Class B)	322.46539	Class B	Well constrained
2187	J E Corette Plant	Emigrant fault, northern section	96.66855	<130,000	Moderately constrained
2240	Lon Wright	Crooked Creek fault (Class B)	329.61791	Class B	Well constrained
2277	Sheldon	Crooked Creek fault (Class B)	272.45888	Class B	Well constrained
2291	North Omaha	Crooked Creek fault (Class B)	339.68748	Class B	Well constrained
2324	Reid Gardner	California Wash fault	2.63364	<15,000	Moderately constrained
2364	Merrimack	Crooked Creek fault (Class B)	1469.66080	Class B	Well constrained
2367	Schiller	Crooked Creek fault (Class B)	1501.72964	Class B	Well constrained
2378	B L England	Meers fault, southeastern section	1269.38081	<15,000	Well constrained
2403	PSEG Hudson Generating Station	Meers fault, southeastern section	1312.42009	<15,000	Well constrained
2408	PSEG Mercer Generating Station	Meers fault, southeastern section	1273.29280	<15,000	Well constrained
2434	Howard Down	Meers fault, southeastern section	1251.11753	<15,000	Well constrained
2442	Four Corners	Nacimiento fault, northern section	88.31603	<1,600,000	Well constrained
2451	San Juan	Unnamed faults near San Miguel Canyon (Class B)	83.94171	Class B	Well constrained
2468	Raton ⁽¹⁾	Goodpasture fault	20.46758	<1,600,000	Well constrained
2527	GMMGreenidge LLC	Crooked Creek fault (Class B)	1206.64031	Class B	Well constrained
2535	Cayuga Operating Company	Crooked Creek fault (Class B)	1220.62425	Class B	Well constrained
2549	C R Huntley Generating Station	Crooked Creek fault (Class B)	1117.88362	Class B	Well constrained
2554	Dunkirk Generating Plant	Crooked Creek fault (Class B)	1091.34049	Class B	Well constrained
2682	S A Carlson	Crooked Creek fault (Class B)	1090.77464	Class B	Well constrained
2706	Asheville	Meers fault, southeastern section	844.55945	<15,000	Well constrained

Exhibit L-1: Fault Line Data Listed by Plant

Plant ID	Plant Name	Nearest Fault	Distance (miles)	Age	Fault Type
2708	Cape Fear	Meers fault, southeastern section	1030.21976	<15,000	Well constrained
2709	HF Lee Plant	Meers fault, southeastern section	1082.25890	<15,000	Well constrained
2712	Roxboro	Meers fault, southeastern section	1027.90712	<15,000	Well constrained
2713	L V Sutton Steam	Meers fault, southeastern section	1095.46827	<15,000	Well constrained
2718	G G Allen	Meers fault, southeastern section	927.08175	<15,000	Well constrained
2720	Buck	Meers fault, southeastern section	959.38408	<15,000	Well constrained
2721	Cliffside	Meers fault, southeastern section	887.04442	<15,000	Well constrained
2727	Marshall	Meers fault, southeastern section	928.30012	<15,000	Well constrained
2732	Riverbend	Meers fault, southeastern section	928.48306	<15,000	Well constrained
2790	R M Heskett	Brockton-Froid fault zone (Class B)	188.08345	Class B	Well constrained
2817	Leland Olds	Brockton-Froid fault zone (Class B)	156.26997	Class B	Well constrained
2823	Milton R Young	Brockton-Froid fault zone (Class B)	168.15246	Class B	Well constrained
2824	Stanton	Brockton-Froid fault zone (Class B)	155.62587	Class B	Well constrained
2828	Cardinal	Meers fault, southeastern section	988.22749	<15,000	Well constrained
2830	Walter C Beckjord	Meers fault, southeastern section	787.62066	<15,000	Well constrained
2832	Miami Fort	Meers fault, southeastern section	765.94263	<15,000	Well constrained
2835	FirstEnergy Ashtabula	Crooked Creek fault (Class B)	1016.22354	Class B	Well constrained
2836	Avon Lake	Crooked Creek fault (Class B)	949.35680	Class B	Well constrained
2837	FirstEnergy Eastlake	Crooked Creek fault (Class B)	980.84769	Class B	Well constrained
2838	FirstEnergy Lake Shore	Crooked Creek fault (Class B)	969.58118	Class B	Well constrained
2840	Conesville	Meers fault, southeastern section	928.48257	<15,000	Well constrained
2843	Picway	Meers fault, southeastern section	866.49348	<15,000	Well constrained
2848	O H Hutchings	Meers fault, southeastern section	801.67896	<15,000	Well constrained
2850	J M Stuart	Meers fault, southeastern section	810.20361	<15,000	Well constrained
2861	Niles	Meers fault, southeastern section	1003.91122	<15,000	Well constrained
2866	FirstEnergy W H Sammis	Meers fault, southeastern section	994.86450	<15,000	Well constrained
2872	Muskingum River	Meers fault, southeastern section	925.87984	<15,000	Well constrained
2876	Kyger Creek	Meers fault, southeastern section	892.05435	<15,000	Well constrained
2878	FirstEnergy Bay Shore	Crooked Creek fault (Class B)	886.52580	Class B	Well constrained
2914	Dover	Meers fault, southeastern section	955.44801	<15,000	Well constrained
2917	Hamilton	Meers fault, southeastern section	784.54228	<15,000	Well constrained
2935	Orrville	Meers fault, southeastern section	949.53602	<15,000	Well constrained
2936	Painesville	Crooked Creek fault (Class B)	990.59101	Class B	Well constrained
2943	Shelby Municipal Light Plant	Meers fault, southeastern section	909.65129	<15,000	Well constrained
2952	Muskogee	Meers fault, southeastern section	176.29801	<15,000	Well constrained
2963	Northeastern	Meers fault, southeastern section	181.82410	<15,000	Well constrained
3098	Elrama Power Plant	Meers fault, southeastern section	1023.07500	<15,000	Well constrained
3113	Portland	Meers fault, southeastern section	1266.04665	<15,000	Well constrained
3115	Titus	Meers fault, southeastern section	1217.43325	<15,000	Well constrained
3118	Conemaugh	Meers fault, southeastern section	1066.43060	<15,000	Well constrained
3122	Homer City Station	Meers fault, southeastern section	1062.37494	<15,000	Well constrained
3130	Seward	Meers fault, southeastern section	1068.16765	<15,000	Well constrained
3131	Shawville	Meers fault, southeastern section	1112.43502	<15,000	Well constrained
3136	Keystone	Meers fault, southeastern section	1058.37446	<15,000	Well constrained
3138	New Castle Plant	Meers fault, southeastern section	1016.14375	<15,000	Well constrained
3140	PPL Brunner Island	Meers fault, southeastern section	1176.11531	<15,000	Well constrained
3149	PPL Montour	Meers fault, southeastern section	1192.40416	<15,000	Well constrained
3152	Sunbury Generation LP	Meers fault, southeastern section	1181.21049	<15,000	Well constrained
3178	FirstEnergy Armstrong Power Station	Meers fault, southeastern section	1058.00916	<15,000	Well constrained
3179	Hatfields Ferry Power Station	Meers fault, southeastern section	1015.33196	<15,000	Well constrained
3181	FirstEnergy Mitchell Power Station	Meers fault, southeastern section	1020.00744	<15,000	Well constrained

Exhibit L-1: Fault Line Data Listed by Plant

Plant ID	Plant Name	Nearest Fault	Distance (miles)	Age	Fault Type
3251	H B Robinson	Meers fault, southeastern section	977.74708	<15,000	Well constrained
3264	W S Lee	Meers fault, southeastern section	853.96864	<15,000	Well constrained
3280	Canadys Steam	Meers fault, southeastern section	968.07733	<15,000	Well constrained
3287	McMeekin	Meers fault, southeastern section	923.95729	<15,000	Well constrained
3295	Urquhart	Meers fault, southeastern section	893.62010	<15,000	Well constrained
3297	Waterree	Meers fault, southeastern section	958.41190	<15,000	Well constrained
3298	Williams	Meers fault, southeastern section	1006.25774	<15,000	Well constrained
3319	Jefferies	Meers fault, southeastern section	999.84573	<15,000	Well constrained
3325	Ben French	South Granite Mountains fault system, Seminole Mountains section(Class B)	213.38473	Class B	Moderately constrained
3393	Allen Steam Plant	Meers fault, southeastern section	438.13140	<15,000	Well constrained
3396	Bull Run	Meers fault, southeastern section	759.16585	<15,000	Well constrained
3399	Cumberland	Meers fault, southeastern section	577.72020	<15,000	Well constrained
3403	Gallatin	Meers fault, southeastern section	642.54027	<15,000	Well constrained
3405	John Sevier	Meers fault, southeastern section	823.20620	<15,000	Well constrained
3406	Johnsonville	Meers fault, southeastern section	557.21936	<15,000	Well constrained
3407	Kingston	Meers fault, southeastern section	739.65966	<15,000	Well constrained
3470	W A Parish	Meers fault, southeastern section	389.67742	<15,000	Well constrained
3497	Big Brown	Meers fault, southeastern section	234.05289	<15,000	Well constrained
3644	Carbon	Pleasant Valley fault zone, unnamed faults	11.55173	<1,600,000	Well constrained
3775	Clinch River	Meers fault, southeastern section	865.92097	<15,000	Well constrained
3776	Glen Lyn	Meers fault, southeastern section	937.96895	<15,000	Well constrained
3788	Potomac River	Meers fault, southeastern section	1144.50477	<15,000	Well constrained
3796	Bremo Bluff	Meers fault, southeastern section	1072.82202	<15,000	Well constrained
3797	Chesterfield	Meers fault, southeastern section	1118.03153	<15,000	Well constrained
3803	Chesapeake	Meers fault, southeastern section	1173.32601	<15,000	Well constrained
3809	Yorktown	Meers fault, southeastern section	1165.43575	<15,000	Well constrained
3845	TransAlta Centralia Generation	Tacoma fault zone	42.11531	<15,000	Inferred
3935	John E Amos	Meers fault, southeastern section	900.49762	<15,000	Well constrained
3936	Kanawha River	Meers fault, southeastern section	917.29579	<15,000	Well constrained
3938	Philip Sporn	Meers fault, southeastern section	902.97848	<15,000	Well constrained
3942	FirstEnergy Albright	Meers fault, southeastern section	1023.52168	<15,000	Well constrained
3943	FirstEnergy Fort Martin Power Station	Meers fault, southeastern section	1012.88280	<15,000	Well constrained
3944	FirstEnergy Harrison Power Station	Meers fault, southeastern section	987.78653	<15,000	Well constrained
3945	FirstEnergy Rivesville	Meers fault, southeastern section	1000.89792	<15,000	Well constrained
3946	FirstEnergy Willow Island	Meers fault, southeastern section	940.20835	<15,000	Well constrained
3947	Kammer	Meers fault, southeastern section	972.17351	<15,000	Well constrained
3948	Mitchell	Meers fault, southeastern section	972.03466	<15,000	Well constrained
3954	Mt Storm	Meers fault, southeastern section	1037.62482	<15,000	Well constrained
3982	Bay Front	Brockton-Froid fault zone (Class B)	609.69666	Class B	Well constrained
4041	South Oak Creek	Crooked Creek fault (Class B)	715.54904	Class B	Well constrained
4042	Valley	Crooked Creek fault (Class B)	717.45229	Class B	Well constrained
4050	Edgewater	Crooked Creek fault (Class B)	749.83442	Class B	Well constrained
4054	Nelson Dewey Coal Refining Facility	Crooked Creek fault (Class B)	581.46456	Class B	Well constrained
4057	Rock River ^(g)	Crooked Creek fault (Class B)	659.67376	Class B	Well constrained
4072	Pulliam	Crooked Creek fault (Class B)	769.19629	Class B	Well constrained
4078	Weston	Brockton-Froid fault zone (Class B)	704.68573	Class B	Well constrained
4125	Manitowoc	Crooked Creek fault (Class B)	765.18753	Class B	Well constrained
4140	Alma	Crooked Creek fault (Class B)	620.96061	Class B	Well constrained
4143	Genoa	Crooked Creek fault (Class B)	608.54651	Class B	Well constrained

Exhibit L-1: Fault Line Data Listed by Plant

Plant ID	Plant Name	Nearest Fault	Distance (miles)	Age	Fault Type
4150	Neil Simpson	Stagner Creek fault	142.13394	<15,000	Moderately constrained
4158	Dave Johnston	South Granite Mountains fault system, Seminole Mountains section(Class B)	67.07904	Class B	Moderately constrained
4162	Naughton	Elk Mountain fault	10.64772	<1,600,000	Moderately constrained
4259	Endicott Station	Crooked Creek fault (Class B)	831.27487	Class B	Well constrained
4271	John P Madgett	Crooked Creek fault (Class B)	620.87916	Class B	Well constrained
4941	Navajo	Bright Angel fault system (Class B)	13.05880	Class B	Well constrained
6002	James H Miller Jr	Meers fault, southeastern section	613.88020	<15,000	Well constrained
6004	FirstEnergy Pleasants Power Station	Meers fault, southeastern section	940.50366	<15,000	Well constrained
6009	White Bluff	Meers fault, southeastern section	332.65517	<15,000	Well constrained
6016	Duck Creek	Crooked Creek fault (Class B)	554.60043	Class B	Well constrained
6017	Newton	Meers fault, southeastern section	598.63133	<15,000	Well constrained
6018	East Bend	Meers fault, southeastern section	759.02882	<15,000	Well constrained
6019	W H Zimmer	Meers fault, southeastern section	788.44101	<15,000	Well constrained
6021	Craig	Killarney faults	30.58788	<1,600,000	Well constrained
6030	Coal Creek	Brockton-Froid fault zone (Class B)	159.37185	Class B	Well constrained
6031	Killen Station	Meers fault, southeastern section	821.66782	<15,000	Well constrained
6034	Belle River	Crooked Creek fault (Class B)	950.15147	Class B	Well constrained
6041	H L Spurlock	Meers fault, southeastern section	805.27920	<15,000	Well constrained
6052	Wansley	Meers fault, southeastern section	725.73186	<15,000	Well constrained
6055	Big Cajun 2	Meers fault, southeastern section	471.53143	<15,000	Well constrained
6061	R D Morrow	Meers fault, southeastern section	546.67607	<15,000	Well constrained
6064	Nearman Creek	Crooked Creek fault (Class B)	302.66720	Class B	Well constrained
6065	Iatan	Crooked Creek fault (Class B)	297.03953	Class B	Well constrained
6068	Jeffrey Energy Center	Crooked Creek fault (Class B)	241.09897	Class B	Well constrained
6071	Trimble County	Meers fault, southeastern section	725.18667	<15,000	Well constrained
6073	Victor J Daniel Jr	Meers fault, southeastern section	611.42058	<15,000	Well constrained
6076	Colstrip	Brockton-Froid fault zone (Class B)	169.78436	Class B	Well constrained
6077	Gerald Gentleman	Cheraw fault	210.05195	<15,000	Well constrained
6082	Somerset Operating Co LLC	Crooked Creek fault (Class B)	1139.13636	Class B	Well constrained
6085	R M Schahfer	Crooked Creek fault (Class B)	709.21073	Class B	Well constrained
6089	Lewis & Clark	Brockton-Froid fault zone (Class B)	46.48648	Class B	Well constrained
6090	Sherburne County	Brockton-Froid fault zone (Class B)	513.53255	Class B	Well constrained
6094	FirstEnergy Bruce Mansfield	Meers fault, southeastern section	1007.00669	<15,000	Well constrained
6095	Sooner	Meers fault, southeastern section	136.47116	<15,000	Well constrained
6096	Nebraska City	Crooked Creek fault (Class B)	309.91401	Class B	Well constrained
6098	Big Stone	Brockton-Froid fault zone (Class B)	412.50786	Class B	Well constrained
6101	Wyodak	Stagner Creek fault	142.21226	<15,000	Moderately constrained
6106	Boardman	Columbia Hills structures (Class B)	10.53933	Class B	Well constrained
6113	Gibson	Meers fault, southeastern section	606.95877	<15,000	Well constrained
6124	McIntosh	Meers fault, southeastern section	950.36529	<15,000	Well constrained
6136	Gibbons Creek	Meers fault, southeastern section	307.66798	<15,000	Well constrained
6137	A B Brown	Meers fault, southeastern section	598.56014	<15,000	Well constrained
6138	Flint Creek	Meers fault, southeastern section	227.20562	<15,000	Well constrained
6139	Welsh	Meers fault, southeastern section	220.00667	<15,000	Well constrained
6146	Martin Lake	Meers fault, southeastern section	264.80014	<15,000	Well constrained
6147	Monticello	Meers fault, southeastern section	209.29828	<15,000	Well constrained
6155	Rush Island	Meers fault, southeastern section	483.30032	<15,000	Well constrained
6165	Hunter	Joes Valley fault zone (Class B)	10.70939	Class B	Well constrained
6166	Rockport	Meers fault, southeastern section	632.23239	<15,000	Well constrained
6170	Pleasant Prairie	Crooked Creek fault (Class B)	702.90866	Class B	Well constrained
6177	Coronado	Coyote Wash fault	11.98541	<750,000	Well constrained

Exhibit L-1: Fault Line Data Listed by Plant

Plant ID	Plant Name	Nearest Fault	Distance (miles)	Age	Fault Type
6178	Coletto Creek	Dugout Wells fault	346.76481	<1,600,000	Moderately constrained
6179	Fayette Power Project	Meers fault, southeastern section	341.25632	<15,000	Well constrained
6180	Oak Grove ⁽ⁿ⁾	Meers fault, southeastern section	264.52720	<15,000	Well constrained
6181	J T Deely	Dugout Wells fault	279.02183	<1,600,000	Moderately constrained
6183	San Miguel	Dugout Wells fault	273.95755	<1,600,000	Moderately constrained
6190	Brame Energy Center	Meers fault, southeastern section	382.91220	<15,000	Well constrained
6193	Harrington	Crooked Creek fault (Class B)	145.24090	Class B	Well constrained
6194	Tolk	Guadalupe fault	180.91508	<15,000	Well constrained
6195	John Twitty Energy Center	Meers fault, southeastern section	309.26103	<15,000	Well constrained
6204	Laramie River Station	South Granite Mountains fault system, Seminole Mountains section(Class B)	88.51175	Class B	Moderately constrained
6213	Merom	Meers fault, southeastern section	637.67190	<15,000	Well constrained
6225	Jasper 2	Meers fault, southeastern section	648.45144	<15,000	Well constrained
6238	Pearl Station	Crooked Creek fault (Class B)	505.40688	Class B	Well constrained
6248	Pawnee	Valmont fault (Class B)	76.32311	Class B	Well constrained
6249	Winyah	Meers fault, southeastern section	1032.39955	<15,000	Well constrained
6250	Mayo	Meers fault, southeastern section	1037.47471	<15,000	Well constrained
6254	Ottumwa	Crooked Creek fault (Class B)	457.06243	Class B	Well constrained
6257	Scherer	Meers fault, southeastern section	796.79985	<15,000	Well constrained
6264	Mountaineer	Meers fault, southeastern section	902.62764	<15,000	Well constrained
6288	Healy	Unnamed faults in Strait of Juan de Fuca and Puget Sound (Class B)	1390.28209	Class B	Well constrained
6469	Antelope Valley	Brockton-Froid fault zone (Class B)	133.58260	Class B	Well constrained
6481	Intermountain Power Project	Sugarville area faults	0.53103	<15,000	Well constrained
6639	R D Green	Meers fault, southeastern section	603.85435	<15,000	Well constrained
6641	Independence	Meers fault, southeastern section	374.15276	<15,000	Well constrained
6648	Sandow No 4	Meers fault, southeastern section	293.71213	<15,000	Well constrained
6664	Louisa	Crooked Creek fault (Class B)	527.03889	Class B	Well constrained
6705	Warrick	Meers fault, southeastern section	617.53137	<15,000	Well constrained
6761	Rawhide	Valmont fault (Class B)	57.65824	Class B	Well constrained
6768	Sikeston Power Station	Meers fault, southeastern section	483.66376	<15,000	Well constrained
6772	Hugo	Meers fault, southeastern section	167.80203	<15,000	Well constrained
6823	D B Wilson	Meers fault, southeastern section	621.47681	<15,000	Well constrained
7030	Twin Oaks Power One	Meers fault, southeastern section	264.52720	<15,000	Well constrained
7097	J K Spruce	Dugout Wells fault	279.16777	<1,600,000	Moderately constrained
7210	Cope	Meers fault, southeastern section	942.02203	<15,000	Well constrained
7213	Clover	Meers fault, southeastern section	1048.06636	<15,000	Well constrained
7242	Polk	Meers fault, southeastern section	1037.51748	<15,000	Well constrained
7343	George Neal South	Crooked Creek fault (Class B)	382.82789	Class B	Well constrained
7504	Neil Simpson II	Stagner Creek fault	142.18073	<15,000	Moderately constrained
7537	North Branch	Meers fault, southeastern section	1035.30027	<15,000	Well constrained
7549	Milwaukee County	Crooked Creek fault (Class B)	713.69734	Class B	Well constrained
7652	US DOE Savannah River Site (D Area)	Meers fault, southeastern section	905.83194	<15,000	Well constrained
7790	Bonanza	Duchesne-Pleasant Valley fault system (Class B)	34.60105	Class B	Well constrained
7902	Pirkey	Meers fault, southeastern section	259.68090	<15,000	Well constrained
8023	Columbia	Crooked Creek fault (Class B)	673.33500	Class B	Well constrained
8042	Belews Creek	Meers fault, southeastern section	975.80438	<15,000	Well constrained
8066	Jim Bridger	Continental fault (Class B)	38.21326	Class B	Moderately constrained
8069	Huntington	Joes Valley fault zone (Class B)	8.33625	Class B	Well constrained
8102	General James M Gavin	Meers fault, southeastern section	892.96641	<15,000	Well constrained
8219	Ray D Nixon	Ute Pass fault zone	8.14708	<750,000	Well constrained

Exhibit L-1: Fault Line Data Listed by Plant

Plant ID	Plant Name	Nearest Fault	Distance (miles)	Age	Fault Type
8222	Coyote	Brockton-Froid fault zone (Class B)	140.13582	Class B	Well constrained
8223	Springerville	Coyote Wash fault	4.95542	<750,000	Moderately constrained
8224	North Valmy	Unnamed faults north of Ellison siding	1.78820	<15,000	Moderately constrained
8226	Cheswick Power Plant	Meers fault, southeastern section	1034.47105	<15,000	Well constrained
10002	ACE Cogeneration Facility	Wilson Canyon fault	2.76282	<1,600,000	Inferred
10003	Colorado Energy Nations Company	Graben near Golden (Class B)	0.96095	Class B	Well constrained
10030	NRG Energy Center Dover	Meers fault, southeastern section	1222.48238	<15,000	Well constrained
10043	Logan Generating Company LP	Meers fault, southeastern section	1235.66974	<15,000	Well constrained
10071	Portsmouth Genco LLC	Meers fault, southeastern section	1170.73024	<15,000	Well constrained
10075	Taconite Harbor Energy Center	Brockton-Froid fault zone (Class B)	594.61477	Class B	Well constrained
10113	John B Rich Memorial Power Station	Meers fault, southeastern section	1210.46319	<15,000	Well constrained
10143	Colver Power Project	Meers fault, southeastern section	1082.00964	<15,000	Well constrained
10148	White Pine Electric Power	Brockton-Froid fault zone (Class B)	672.77012	Class B	Well constrained
10151	Grant Town Power Plant	Meers fault, southeastern section	998.88324	<15,000	Well constrained
10343	Foster Wheeler Mt Carmel Cogen	Meers fault, southeastern section	1198.51977	<15,000	Well constrained
10367	East Third Street Power Plant ^(a)	unnamed fault	11.85497	<1,600,000	Inferred
10369	Wilbur West Power Plant ^(a)	unnamed fault	11.85497	<1,600,000	Inferred
10370	Wilbur East Power Plant ^(a)	unnamed fault	11.85497	<1,600,000	Inferred
10371	Nichols Road Power Plant ^(a)	unnamed fault	11.85497	<1,600,000	Inferred
10377	James River Genco LLC	Meers fault, southeastern section	1123.64089	<15,000	Well constrained
10378	CPI USA NC Southport	Meers fault, southeastern section	1097.54586	<15,000	Well constrained
10379	CPI USA NC Roxboro	Meers fault, southeastern section	1033.71643	<15,000	Well constrained
10380	Elizabethtown Power LLC	Meers fault, southeastern section	1057.24242	<15,000	Well constrained
10381	Coastal Carolina Clean Power ^(c)	Meers fault, southeastern section	1082.25890	<15,000	Well constrained
10384	Edgecombe Genco LLC	Meers fault, southeastern section	1097.69620	<15,000	Well constrained
10464	Black River Generation	Crooked Creek fault (Class B)	1279.70359	Class B	Well constrained
10495	Rumford Cogeneration	Crooked Creek fault (Class B)	1525.95139	Class B	Well constrained
10566	Chambers Cogeneration LP	Meers fault, southeastern section	1230.98260	<15,000	Well constrained
10603	Ebensburg Power	Meers fault, southeastern section	1082.72327	<15,000	Well constrained
10604	Hawaiian Comm & Sugar Puunene Mill ^(b)	Kohala Volcano, Kohala headwall section (Class B)	170.63360	Class B	Well constrained
10640	Stockton Cogen	unnamed fault	11.85497	<1,600,000	Inferred
10641	Cambria Cogen	Meers fault, southeastern section	1085.20051	<15,000	Well constrained
10671	AES Shady Point LLC	Meers fault, southeastern section	198.66469	<15,000	Well constrained
10672	Cedar Bay Generating Company LP	Meers fault, southeastern section	970.57931	<15,000	Well constrained
10673	AES Hawaii	Kohala Volcano, Kohala headwall section (Class B)	170.63360	Class B	Well constrained
10676	AES Beaver Valley Partners Beaver Valley	Meers fault, southeastern section	1010.48892	<15,000	Well constrained
10678	AES Warrior Run Cogeneration Facility	Meers fault, southeastern section	1068.80004	<15,000	Well constrained
10686	Rapids Energy Center	Brockton-Froid fault zone (Class B)	484.64097	Class B	Well constrained
10743	Morgantown Energy Facility	Meers fault, southeastern section	1010.09611	<15,000	Well constrained
10768	Rio Bravo Jasmin	unnamed faults near Rag Gulch	0.72805	<1,600,000	Moderately constrained
10769	Rio Bravo Poso	Poso Creek fault	0.06842	<1,600,000	Inferred
10771	Hopewell Power Station	Meers fault, southeastern section	1123.00871	<15,000	Well constrained
10774	Southampton Power Station	Meers fault, southeastern section	1136.94231	<15,000	Well constrained
10784	Colstrip Energy LP	Brockton-Froid fault zone (Class B)	170.03353	Class B	Well constrained

Exhibit L-1: Fault Line Data Listed by Plant

Plant ID	Plant Name	Nearest Fault	Distance (miles)	Age	Fault Type
50039	Kline Township Cogen Facility	Meers fault, southeastern section	1221.72404	<15,000	Well constrained
50202	WPS Power Niagara	Crooked Creek fault (Class B)	1116.35423	Class B	Well constrained
50407	Mobile Energy Services LLC	Meers fault, southeastern section	629.43410	<15,000	Well constrained
50611	Westwood Generation LLC	Meers fault, southeastern section	1195.48507	<15,000	Well constrained
50651	Syracuse Energy	Crooked Creek fault (Class B)	1245.97276	Class B	Well constrained
50776	Panther Creek Energy Facility	Meers fault, southeastern section	1226.88727	<15,000	Well constrained
50835	TES Filer City Station	Crooked Creek fault (Class B)	824.71343	Class B	Well constrained
50879	Wheelabrator Frackville Energy	Meers fault, southeastern section	1211.30739	<15,000	Well constrained
50888	Northampton Generating Company LP	Meers fault, southeastern section	1243.65361	<15,000	Well constrained
50951	Sunnyside Cogen Associates	Price River area faults (Class B)	10.52571	Class B	Well constrained
50974	Scrubgrass Generating Company LP	Meers fault, southeastern section	1049.45320	<15,000	Well constrained
50976	Indiantown Cogeneration LP	Meers fault, southeastern section	1137.02910	<15,000	Well constrained
52007	Mecklenburg Power Station	Meers fault, southeastern section	1056.52500	<15,000	Well constrained
54035	Roanoke Valley Energy Facility I	Meers fault, southeastern section	1104.44297	<15,000	Well constrained
54081	Spruance Genco LLC	Meers fault, southeastern section	1115.83573	<15,000	Well constrained
54144	Piney Creek Project	Meers fault, southeastern section	1064.50638	<15,000	Well constrained
54304	Birchwood Power	Meers fault, southeastern section	1126.18973	<15,000	Well constrained
54634	St Nicholas Cogen Project	Meers fault, southeastern section	1212.15943	<15,000	Well constrained
54755	Roanoke Valley Energy Facility II	Meers fault, southeastern section	1104.44297	<15,000	Well constrained
55076	Red Hills Generating Facility	Meers fault, southeastern section	501.72885	<15,000	Well constrained
55245	Tuscola Station	Crooked Creek fault (Class B)	621.55289	Class B	Well constrained
55479	Wygen I	Stagner Creek fault	142.19922	<15,000	Moderately constrained
55749	Hardin Generator Project	Unnamed faults near Opal Creek	133.44269	<15,000	Well constrained
55856	Prairie State Generatng Station ^(r)	Meers fault, southeastern section	504.30689	<15,000	Well constrained
56068	Elm Road Generating Station ^(h)	Crooked Creek fault (Class B)	715.54904	Class B	Well constrained
56224	TS Power Plant ^(q)	Unnamed faults north of Ellison siding	1.78820	<15,000	Moderately constrained
56319	Wygen 2 ^(m)	Stagner Creek fault	142.21226	<15,000	Moderately constrained
56456	Plum Point Energy Station ^(d)	Meers fault, southeastern section	438.13140	<15,000	Well constrained
56564	John W Turk Jr Power Plant ^(p)	Meers fault, southeastern section	259.68090	<15,000	Well constrained
56596	Wygen III ^(m)	Stagner Creek fault	142.21226	<15,000	Moderately constrained
56609	Dry Fork Station ^(m)	Stagner Creek fault	142.21226	<15,000	Moderately constrained
56671	Longview Power LLC ^(f)	Meers fault, southeastern section	1012.88280	<15,000	Well constrained
56808	Virginia City Hybrid Energy Center ^(e)	Meers fault, southeastern section	865.92097	<15,000	Well constrained
56848	Haverhill North Cogeneration Facility ^(j)	Meers fault, southeastern section	821.66782	<15,000	Well constrained
68029	AES Puerto Rico Cogeneration Facility ^(s)	N/A	N/A	N/A	N/A

- (a) Based on close proximity to survey of plant 10640.
(b) Based on close proximity to survey of plant 10673.
(c) Based on close proximity to survey of plant 2709.
(d) Based on close proximity to survey of plant 3393.
(e) Based on close proximity to survey of plant 3775.
(f) Based on close proximity to survey of plant 3943.
(g) Based on close proximity to survey of plant 3992.
(h) Based on close proximity to survey of plant 4041.
(i) Based on close proximity to survey of plant 470.

Exhibit L-1: Fault Line Data Listed by Plant

Plant ID	Plant Name	Nearest Fault	Distance (miles)	Age	Fault Type
(j) Based on close proximity to survey of plant 6031. (k) Based on close proximity to survey of plant 6077. (m) Based on close proximity to survey of plant 6101. (n) Based on close proximity to survey of plant 7030. (p) Based on close proximity to survey of plant 7902. (q) Based on close proximity to survey of plant 8224. (r) Based on close proximity to survey of plant 889. (s) This site was not surveyed.					

Exhibit L-2: Seismic Impact Data Listed by Plant

Plant ID	Plant Name	County	State	Peak Ground Acceleration (g)
3	Barry	Mobile	AL	0.06
7	Gadsden	Etowah	AL	0.13
8	Gorgas	Walker	AL	0.14
10	Greene County	Greene	AL	0.09
26	E C Gaston	Shelby	AL	0.12
47	Colbert	Colbert	AL	0.15
50	Widows Creek	Jackson	AL	0.17
51	Dolet Hills	De Soto	LA	0.06
56	Charles R Lowman	Washington	AL	0.06
59	Platte	Hall	NE	0.05
60	Whelan Energy Center	Adams	NE	0.04
79	Aurora Energy LLC Chena ^(r)	Fairbanks North Star	AK	N/A
87	Escalante	McKinley	NM	0.12
108	Holcomb	Finney	KS	0.04
113	Cholla	Navajo	AZ	0.08
126	H Wilson Sundt Generating Station	Pima	AZ	0.12
127	Oklaunion	Wilbarger	TX	0.06
130	Cross	Berkeley	SC	0.92
136	Seminole	Putnam	FL	0.05
160	Apache Station	Cochise	AZ	0.10
165	GRDA	Mayes	OK	0.06
207	St Johns River Power Park	Duval	FL	0.06
298	Limestone	Limestone	TX	0.04
384	Joliet 29	Will	IL	0.08
462	W N Clark	Fremont	CO	0.12
465	Arapahoe	Denver	CO	0.10
469	Cherokee	Adams	CO	0.09
470	Comanche	Pueblo	CO	0.08
477	Valmont	Boulder	CO	0.10
492	Martin Drake	El Paso	CO	0.09
508	Lamar Plant ^(f)	Prowers	CO	0.03
525	Hayden	Routt	CO	0.15
527	Nucla	Montrose	CO	0.13
564	Stanton Energy Center	Orange	FL	0.04
568	Bridgeport Station	Fairfield	CT	0.11
594	Indian River Generating Station	Sussex	DE	0.04
602	Brandon Shores	Anne Arundel	MD	0.06
628	Crystal River	Citrus	FL	0.03
641	Crist	Escambia	FL	0.05
642	Scholz	Jackson	FL	0.04
643	Lansing Smith	Bay	FL	0.04
645	Big Bend	Hillsborough	FL	0.03
663	Deerhaven Generating Station	Alachua	FL	0.04
667	Northside Generating Station	Duval	FL	0.06

Exhibit L-2: Seismic Impact Data Listed by Plant

Plant ID	Plant Name	County	State	Peak Ground Acceleration (g)
676	C D McIntosh Jr	Polk	FL	0.03
703	Bowen	Bartow	GA	0.15
708	Hammond	Floyd	GA	0.19
709	Harlee Branch	Putnam	GA	0.09
710	Jack McDonough	Cobb	GA	0.09
727	Mitchell	Dougherty	GA	0.05
728	Yates	Coweta	GA	0.08
733	Kraft	Chatham	GA	0.16
753	Crisp Plant	Worth	GA	0.05
856	E D Edwards	Peoria	IL	0.07
861	Coffeen	Montgomery	IL	0.19
867	Crawford	Cook	IL	0.07
874	Joliet 9	Will	IL	0.08
876	Kincaid Generation LLC	Christian	IL	0.12
879	Powerton	Tazewell	IL	0.07
883	Waukegan	Lake	IL	0.05
884	Will County	Will	IL	0.08
886	Fisk Street	Cook	IL	0.07
887	Joppa Steam	Massac	IL	1.26
889	Baldwin Energy Complex	Randolph	IL	0.30
891	Havana	Mason	IL	0.07
892	Hennepin Power Station	Putnam	IL	0.07
898	Wood River	Madison	IL	0.19
963	Dallman	Sangamon	IL	0.10
976	Marion	Williamson	IL	0.57
981	State Line Energy	Lake	IN	0.07
983	Clifty Creek	Jefferson	IN	0.08
988	Tanners Creek	Dearborn	IN	0.07
990	Harding Street	Marion	IN	0.07
991	Eagle Valley	Morgan	IN	0.09
992	CC Perry K	Marion	IN	0.07
994	AES Petersburg	Pike	IN	0.23
995	Bailly	Porter	IN	0.06
997	Michigan City	La Porte	IN	0.05
1001	Cayuga	Vermillion	IN	0.09
1004	Edwardsport	Knox	IN	0.19
1008	R Gallagher	Floyd	IN	0.10
1010	Wabash River	Vigo	IN	0.12
1012	F B Culley	Warrick	IN	0.27
1024	Crawfordsville	Montgomery	IN	0.08
1032	Logansport	Cass	IN	0.05
1037	Peru	Miami	IN	0.05
1040	Whitewater Valley	Wayne	IN	0.07
1043	Frank E Ratts	Pike	IN	0.23

Exhibit L-2: Seismic Impact Data Listed by Plant

Plant ID	Plant Name	County	State	Peak Ground Acceleration (g)
1046	Dubuque	Dubuque	IA	0.04
1047	Lansing	Allamakee	IA	0.03
1048	Milton L Kapp	Clinton	IA	0.05
1073	Prairie Creek	Linn	IA	0.04
1077	Sutherland	Marshall	IA	0.03
1081	Riverside	Scott	IA	0.05
1082	Walter Scott Jr Energy Center	Pottawattamie	IA	0.05
1091	George Neal North	Woodbury	IA	0.04
1104	Burlington	Des Moines	IA	0.05
1122	Ames Electric Services Power Plant	Story	IA	0.03
1131	Streeter Station	Black Hawk	IA	0.03
1167	Muscatine Plant #1	Muscatine	IA	0.05
1175	Pella	Marion	IA	0.03
1217	Earl F Wisdom	Clay	IA	0.03
1239	Riverton	Cherokee	KS	0.06
1241	La Cygne	Linn	KS	0.05
1250	Lawrence Energy Center	Douglas	KS	0.06
1252	Tecumseh Energy Center	Shawnee	KS	0.06
1295	Quindaro	Wyandotte	KS	0.05
1353	Big Sandy	Lawrence	KY	0.08
1355	E W Brown	Mercer	KY	0.08
1356	Ghent	Carroll	KY	0.07
1357	Green River	Muhlenberg	KY	0.23
1361	Tyrone	Woodford	KY	0.08
1363	Cane Run	Jefferson	KY	0.10
1364	Mill Creek	Jefferson	KY	0.11
1374	Elmer Smith	Daviess	KY	0.23
1378	Paradise	Muhlenberg	KY	0.20
1379	Shawnee	McCracken	KY	1.10
1381	Kenneth C Coleman	Hancock	KY	0.18
1382	HMP&L Station Two Henderson	Henderson	KY	0.31
1383	Robert A Reid	Webster	KY	0.31
1384	Cooper	Pulaski	KY	0.09
1385	Dale	Clark	KY	0.09
1393	R S Nelson	Calcasieu	LA	0.05
1552	C P Crane	Baltimore	MD	0.07
1554	Herbert A Wagner	Anne Arundel	MD	0.06
1570	FirstEnergy R Paul Smith Power Station	Washington	MD	0.06
1571	Chalk Point LLC	Prince Georges	MD	0.05
1572	Dickerson	Montgomery	MD	0.06
1573	Morgantown Generating Plant	Charles	MD	0.06
1606	Mount Tom	Hampden	MA	0.08
1619	Brayton Point	Bristol	MA	0.09
1626	Salem Harbor	Essex	MA	0.14

Exhibit L-2: Seismic Impact Data Listed by Plant				
Plant ID	Plant Name	County	State	Peak Ground Acceleration (g)
1695	B C Cobb	Muskegon	MI	0.03
1702	Dan E Karn	Bay	MI	0.03
1710	J H Campbell	Ottawa	MI	0.03
1720	J C Weadock	Bay	MI	0.03
1723	J R Whiting	Monroe	MI	0.06
1731	Harbor Beach	Huron	MI	0.03
1733	Monroe	Monroe	MI	0.05
1740	River Rouge	Wayne	MI	0.05
1743	St Clair	St Clair	MI	0.04
1745	Trenton Channel	Wayne	MI	0.05
1769	Presque Isle	Marquette	MI	0.02
1771	Escanaba	Delta	MI	0.02
1825	J B Sims	Ottawa	MI	0.03
1830	James De Young	Ottawa	MI	0.03
1831	Eckert Station	Ingham	MI	0.04
1832	Erickson Station	Eaton	MI	0.04
1843	Shiras	Marquette	MI	0.02
1866	Wyandotte	Wayne	MI	0.05
1891	Syl Laskin	St Louis	MN	0.02
1893	Clay Boswell	Itasca	MN	0.02
1897	M L Hibbard	St Louis	MN	0.02
1904	Black Dog	Dakota	MN	0.02
1915	Allen S King	Washington	MN	0.02
1943	Hoot Lake	Otter Tail	MN	0.04
1961	Austin Northeast	Mower	MN	0.02
1979	Hibbing	St Louis	MN	0.02
2008	Silver Lake	Olmsted	MN	0.02
2018	Virginia	St Louis	MN	0.02
2022	Willmar	Kandiyohi	MN	0.03
2049	Jack Watson	Harrison	MS	0.05
2062	Henderson	Leflore	MS	0.15
2076	Asbury	Jasper	MO	0.06
2079	Hawthorn	Jackson	MO	0.05
2080	Montrose	Henry	MO	0.06
2094	Sibley	Jackson	MO	0.05
2098	Lake Road	Buchanan	MO	0.05
2103	Labadie	Franklin	MO	0.17
2104	Meramec	St Louis	MO	0.24
2107	Sioux	St Charles	MO	0.17
2123	Columbia	Boone	MO	0.08
2132	Blue Valley	Jackson	MO	0.05
2144	Marshall	Saline	MO	0.06
2161	James River Power Station	Greene	MO	0.10
2167	New Madrid	New Madrid	MO	1.93

Exhibit L-2: Seismic Impact Data Listed by Plant

Plant ID	Plant Name	County	State	Peak Ground Acceleration (g)
2168	Thomas Hill	Randolph	MO	0.06
2169	Chamois	Osage	MO	0.10
2171	Missouri City	Clay	MO	0.05
2187	J E Corette Plant	Yellowstone	MT	0.05
2240	Lon Wright	Dodge	NE	0.06
2277	Sheldon	Lancaster	NE	0.07
2291	North Omaha	Douglas	NE	0.05
2324	Reid Gardner	Clark	NV	0.25
2364	Merrimack	Merrimack	NH	0.16
2367	Schiller	Rockingham	NH	0.16
2378	B L England	Cape May	NJ	0.06
2403	PSEG Hudson Generating Station	Hudson	NJ	0.17
2408	PSEG Mercer Generating Station	Mercer	NJ	0.12
2434	Howard Down	Cumberland	NJ	0.08
2442	Four Corners	San Juan	NM	0.06
2451	San Juan	San Juan	NM	0.06
2468	Raton ^(h)	Colfax	NM	0.08
2527	GMMGreenidge LLC	Yates	NY	0.06
2535	Cayuga Operating Company	Tompkins	NY	0.06
2549	C R Huntley Generating Station	Erie	NY	0.12
2554	Dunkirk Generating Plant	Chautauqua	NY	0.08
2682	S A Carlson	Chautauqua	NY	0.07
2706	Asheville	Buncombe	NC	0.16
2708	Cape Fear	Chatham	NC	0.08
2709	HF Lee Plant	Wayne	NC	0.07
2712	Roxboro	Person	NC	0.07
2713	L V Sutton Steam	New Hanover	NC	0.11
2718	G G Allen	Gaston	NC	0.12
2720	Buck	Rowan	NC	0.09
2721	Cliffside	Cleveland	NC	0.12
2727	Marshall	Catawba	NC	0.10
2732	Riverbend	Gaston	NC	0.11
2790	R M Heskett	Morton	ND	0.02
2817	Leland Olds	Mercer	ND	0.02
2823	Milton R Young	Oliver	ND	0.02
2824	Stanton	Mercer	ND	0.02
2828	Cardinal	Jefferson	OH	0.05
2830	Walter C Beckjord	Clermont	OH	0.07
2832	Miami Fort	Hamilton	OH	0.07
2835	FirstEnergy Ashtabula	Ashtabula	OH	0.12
2836	Avon Lake	Lorain	OH	0.07
2837	FirstEnergy Eastlake	Lake	OH	0.12
2838	FirstEnergy Lake Shore	Cuyahoga	OH	0.10
2840	Conesville	Coshocton	OH	0.05

Exhibit L-2: Seismic Impact Data Listed by Plant

Plant ID	Plant Name	County	State	Peak Ground Acceleration (g)
2843	Picway	Pickaway	OH	0.06
2848	O H Hutchings	Montgomery	OH	0.07
2850	J M Stuart	Adams	OH	0.09
2861	Niles	Trumbull	OH	0.10
2866	FirstEnergy W H Sammis	Jefferson	OH	0.05
2872	Muskingum River	Washington	OH	0.05
2876	Kyger Creek	Gallia	OH	0.06
2878	FirstEnergy Bay Shore	Lucas	OH	0.06
2914	Dover	Tuscarawas	OH	0.05
2917	Hamilton	Butler	OH	0.07
2935	Orrville	Wayne	OH	0.06
2936	Painesville	Lake	OH	0.13
2943	Shelby Municipal Light Plant	Richland	OH	0.06
2952	Muskogee	Muskogee	OK	0.07
2963	Northeastern	Rogers	OK	0.06
3098	Elrama Power Plant	Washington	PA	0.05
3113	Portland	Northampton	PA	0.11
3115	Titus	Berks	PA	0.11
3118	Conemaugh	Indiana	PA	0.05
3122	Homer City Station	Indiana	PA	0.05
3130	Seward	Indiana	PA	0.05
3131	Shawville	Clearfield	PA	0.05
3136	Keystone	Armstrong	PA	0.05
3138	New Castle Plant	Lawrence	PA	0.07
3140	PPL Brunner Island	York	PA	0.08
3149	PPL Montour	Montour	PA	0.06
3152	Sunbury Generation LP	Snyder	PA	0.06
3178	FirstEnergy Armstrong Power Station	Armstrong	PA	0.06
3179	Hatfields Ferry Power Station	Greene	PA	0.05
3181	FirstEnergy Mitchell Power Station	Washington	PA	0.05
3251	H B Robinson	Darlington	SC	0.21
3264	W S Lee	Anderson	SC	0.15
3280	Canadys Steam	Colleton	SC	0.45
3287	McMeekin	Lexington	SC	0.21
3295	Urquhart	Aiken	SC	0.15
3297	Wateree	Richland	SC	0.28
3298	Williams	Berkeley	SC	1.08
3319	Jefferies	Berkeley	SC	1.32
3325	Ben French	Pennington	SD	0.06
3393	Allen Steam Plant	Shelby	TN	0.59
3396	Bull Run	Anderson	TN	0.22
3399	Cumberland	Stewart	TN	0.29
3403	Gallatin	Sumner	TN	0.13
3405	John Sevier	Hawkins	TN	0.19

Exhibit L-2: Seismic Impact Data Listed by Plant

Plant ID	Plant Name	County	State	Peak Ground Acceleration (g)
3406	Johnsonville	Humphreys	TN	0.32
3407	Kingston	Roane	TN	0.20
3470	W A Parish	Fort Bend	TX	0.03
3497	Big Brown	Freestone	TX	0.04
3644	Carbon	Carbon	UT	0.21
3775	Clinch River	Russell	VA	0.14
3776	Glen Lyn	Giles	VA	0.15
3788	Potomac River	Alexandria	VA	0.06
3796	Bremo Bluff	Fluvanna	VA	0.15
3797	Chesterfield	Chesterfield	VA	0.10
3803	Chesapeake	Chesapeake	VA	0.04
3809	Yorktown	York	VA	0.05
3845	TransAlta Centralia Generation	Lewis	WA	0.53
3935	John E Amos	Putnam	WV	0.07
3936	Kanawha River	Kanawha	WV	0.07
3938	Philip Sporn	Mason	WV	0.06
3942	FirstEnergy Albright	Preston	WV	0.05
3943	FirstEnergy Fort Martin Power Station	Monongalia	WV	0.05
3944	FirstEnergy Harrison Power Station	Harrison	WV	0.05
3945	FirstEnergy Rivesville	Marion	WV	0.05
3946	FirstEnergy Willow Island	Pleasants	WV	0.05
3947	Kammer	Marshall	WV	0.05
3948	Mitchell	Marshall	WV	0.05
3954	Mt Storm	Grant	WV	0.05
3982	Bay Front	Ashland	WI	0.02
4041	South Oak Creek	Milwaukee	WI	0.04
4042	Valley	Milwaukee	WI	0.04
4050	Edgewater	Sheboygan	WI	0.03
4054	Nelson Dewey Coal Refining Facility	Grant	WI	0.03
4057	Rock River ^(f)	Rock	WI	0.04
4072	Pulliam	Brown	WI	0.02
4078	Weston	Marathon	WI	0.02
4125	Manitowoc	Manitowoc	WI	0.03
4140	Alma	Buffalo	WI	0.02
4143	Genoa	Vernon	WI	0.03
4150	Neil Simpson	Campbell	WY	0.11
4158	Dave Johnston	Converse	WY	0.18
4162	Naughton	Lincoln	WY	0.26
4259	Endicott Station	Hillsdale	MI	0.04
4271	John P Madgett	Buffalo	WI	0.02
4941	Navajo	Coconino	AZ	0.12
6002	James H Miller Jr	Jefferson	AL	0.15
6004	FirstEnergy Pleasants Power Station	Pleasants	WV	0.05
6009	White Bluff	Jefferson	AR	0.19

Exhibit L-2: Seismic Impact Data Listed by Plant

Plant ID	Plant Name	County	State	Peak Ground Acceleration (g)
6016	Duck Creek	Fulton	IL	0.07
6017	Newton	Jasper	IL	0.24
6018	East Bend	Boone	KY	0.07
6019	W H Zimmer	Clermont	OH	0.07
6021	Craig	Moffat	CO	0.14
6030	Coal Creek	McLean	ND	0.02
6031	Killen Station	Adams	OH	0.08
6034	Belle River	St Clair	MI	0.04
6041	H L Spurlock	Mason	KY	0.08
6052	Wansley	Heard	GA	0.08
6055	Big Cajun 2	Pointe Coupee	LA	0.05
6061	R D Morrow	Lamar	MS	0.06
6064	Nearman Creek	Wyandotte	KS	0.05
6065	Iatan	Platte	MO	0.05
6068	Jeffrey Energy Center	Pottawatomie	KS	0.09
6071	Trimble County	Trimble	KY	0.08
6073	Victor J Daniel Jr	Jackson	MS	0.05
6076	Colstrip	Rosebud	MT	0.05
6077	Gerald Gentleman	Lincoln	NE	0.03
6082	Somerset Operating Co LLC	Niagara	NY	0.10
6085	R M Schahfer	Jasper	IN	0.06
6089	Lewis & Clark	Richland	MT	0.04
6090	Sherburne County	Sherburne	MN	0.03
6094	FirstEnergy Bruce Mansfield	Beaver	PA	0.06
6095	Sooner	Noble	OK	0.06
6096	Nebraska City	Otoe	NE	0.05
6098	Big Stone	Grant	SD	0.04
6101	Wyodak	Campbell	WY	0.11
6106	Boardman	Morrow	OR	0.18
6113	Gibson	Gibson	IN	0.33
6124	McIntosh	Effingham	GA	0.19
6136	Gibbons Creek	Grimes	TX	0.04
6137	A B Brown	Posey	IN	0.35
6138	Flint Creek	Benton	AR	0.07
6139	Welsh	Titus	TX	0.06
6146	Martin Lake	Rusk	TX	0.06
6147	Monticello	Titus	TX	0.06
6155	Rush Island	Jefferson	MO	0.28
6165	Hunter	Emery	UT	0.26
6166	Rockport	Spencer	IN	0.22
6170	Pleasant Prairie	Kenosha	WI	0.05
6177	Coronado	Apache	AZ	0.08
6178	Coleto Creek	Goliad	TX	0.04
6179	Fayette Power Project	Fayette	TX	0.03

Exhibit L-2: Seismic Impact Data Listed by Plant

Plant ID	Plant Name	County	State	Peak Ground Acceleration (g)
6180	Oak Grove ^(m)	Robertson	TX	0.04
6181	J T Deely	Bexar	TX	0.05
6183	San Miguel	Atascosa	TX	0.05
6190	Brame Energy Center	Rapides	LA	0.05
6193	Harrington	Potter	TX	0.09
6194	Tolk	Lamb	TX	0.04
6195	John Twitty Energy Center	Greene	MO	0.09
6204	Laramie River Station	Platte	WY	0.11
6213	Merom	Sullivan	IN	0.18
6225	Jasper 2	Dubois	IN	0.18
6238	Pearl Station	Pike	IL	0.10
6248	Pawnee	Morgan	CO	0.05
6249	Winyah	Georgetown	SC	0.49
6250	Mayo	Person	NC	0.07
6254	Ottumwa	Wapello	IA	0.04
6257	Scherer	Monroe	GA	0.07
6264	Mountaineer	Mason	WV	0.06
6288	Healy ^(r)	Denali Borough	AK	N/A
6469	Antelope Valley	Mercer	ND	0.02
6481	Intermountain Power Project	Millard	UT	0.15
6639	R D Green	Webster	KY	0.31
6641	Independence	Independence	AR	0.41
6648	Sadow No 4	Milam	TX	0.03
6664	Louisa	Louisa	IA	0.05
6705	Warrick	Warrick	IN	0.27
6761	Rawhide	Larimer	CO	0.09
6768	Sikeston Power Station	Scott	MO	1.44
6772	Hugo	Choctaw	OK	0.07
6823	D B Wilson	Ohio	KY	0.22
7030	Twin Oaks Power One	Robertson	TX	0.04
7097	J K Spruce	Bexar	TX	0.05
7210	Cope	Orangeburg	SC	0.27
7213	Clover	Halifax	VA	0.07
7242	Polk	Polk	FL	0.03
7343	George Neal South	Woodbury	IA	0.04
7504	Neil Simpson II	Campbell	WY	0.11
7537	North Branch	Grant	WV	0.05
7549	Milwaukee County	Milwaukee	WI	0.04
7652	US DOE Savannah River Site (D Area)	Aiken	SC	0.16
7790	Bonanza	Uintah	UT	0.15
7902	Pirkey	Harrison	TX	0.06
8023	Columbia	Columbia	WI	0.03
8042	Belews Creek	Stokes	NC	0.08
8066	Jim Bridger	Sweetwater	WY	0.17

Exhibit L-2: Seismic Impact Data Listed by Plant

Plant ID	Plant Name	County	State	Peak Ground Acceleration (g)
8069	Huntington	Emery	UT	0.26
8102	General James M Gavin	Gallia	OH	0.06
8219	Ray D Nixon	El Paso	CO	0.09
8222	Coyote	Mercer	ND	0.02
8223	Springerville	Apache	AZ	0.10
8224	North Valmy	Humboldt	NV	0.26
8226	Cheswick Power Plant	Allegheny	PA	0.05
10002	ACE Cogeneration Facility	San Bernardino	CA	0.44
10003	Colorado Energy Nations Company	Jefferson	CO	0.10
10030	NRG Energy Center Dover	Kent	DE	0.06
10043	Logan Generating Company LP	Gloucester	NJ	0.11
10071	Portsmouth Genco LLC	Portsmouth City	VA	0.05
10075	Taconite Harbor Energy Center	Cook	MN	0.02
10113	John B Rich Memorial Power Station	Schuylkill	PA	0.08
10143	Colver Power Project	Cambria	PA	0.05
10148	White Pine Electric Power	Ontonagon	MI	0.02
10151	Grant Town Power Plant	Marion	WV	0.05
10343	Foster Wheeler Mt Carmel Cogen	Northumberland	PA	0.07
10367	East Third Street Power Plant ^(a)	Contra Costa	CA	0.33
10369	Wilbur West Power Plant ^(a)	Contra Costa	CA	0.33
10370	Wilbur East Power Plant ^(a)	Contra Costa	CA	0.33
10371	Nichols Road Power Plant ^(a)	Contra Costa	CA	0.33
10377	James River Genco LLC	City of Hopewell	VA	0.08
10378	CPI USA NC Southport	Brunswick	NC	0.13
10379	CPI USA NC Roxboro	Person	NC	0.07
10380	Elizabethtown Power LLC	Bladen	NC	0.13
10381	Coastal Carolina Clean Power ^(b)	Duplin	NC	0.07
10384	Edgecombe Genco LLC	Edgecombe	NC	0.06
10464	Black River Generation	Jefferson	NY	0.10
10495	Rumford Cogeneration	Oxford	ME	0.13
10566	Chambers Cogeneration LP	Salem	NJ	0.11
10603	Ebensburg Power	Cambria	PA	0.05
10604	Hawaiian Comm & Sugar Puunene Mill ^(r)	Maui	HI	N/A
10640	Stockton Cogen	San Joaquin	CA	0.33
10641	Cambria Cogen	Cambria	PA	0.05
10671	AES Shady Point LLC	Leflore	OK	0.08
10672	Cedar Bay Generating Company LP	Duval	FL	0.06
10673	AES Hawaii ^(r)	Oahu	HI	N/A
10676	AES Beaver Valley Partners Beaver Valley	Beaver	PA	0.06
10678	AES Warrior Run Cogeneration Facility	Allegany	MD	0.06
10686	Rapids Energy Center	Itasca	MN	0.02
10743	Morgantown Energy Facility	Monongalia	WV	0.05
10768	Rio Bravo Jasmin	Kern	CA	0.29
10769	Rio Bravo Poso	Kern	CA	0.35

Exhibit L-2: Seismic Impact Data Listed by Plant

Plant ID	Plant Name	County	State	Peak Ground Acceleration (g)
10771	Hopewell Power Station	Hopewell City	VA	0.08
10774	Southampton Power Station	Southampton	VA	0.05
10784	Colstrip Energy LP	Rosebud	MT	0.05
50039	Kline Township Cogen Facility	Schuylkill	PA	0.08
50202	WPS Power Niagara	Niagara	NY	0.12
50407	Mobile Energy Services LLC	Mobile	AL	0.05
50611	Westwood Generation LLC	Schuylkill	PA	0.08
50651	Syracuse Energy	Onondaga	NY	0.06
50776	Panther Creek Energy Facility	Carbon	PA	0.08
50835	TES Filer City Station	Manistee	MI	0.02
50879	Wheelabrator Frackville Energy	Schuylkill	PA	0.08
50888	Northampton Generating Company LP	Northampton	PA	0.10
50951	Sunnyside Cogen Associates	Carbon	UT	0.18
50974	Scrubgrass Generating Company LP	Venango	PA	0.07
50976	Indiantown Cogeneration LP	Martin	FL	0.03
52007	Mecklenburg Power Station	Mecklenburg	VA	0.07
54035	Roanoke Valley Energy Facility I	Halifax	NC	0.06
54081	Spruance Genco LLC	City of Richmond	VA	0.10
54144	Piney Creek Project	Clarion	PA	0.06
54304	Birchwood Power	King George	VA	0.07
54634	St Nicholas Cogen Project	Schuylkill	PA	0.08
54755	Roanoke Valley Energy Facility II	Halifax	NC	0.06
55076	Red Hills Generating Facility	Choctaw	MS	0.11
55245	Tuscola Station	Douglas	IL	0.11
55479	Wygen 1	Campbell	WY	0.11
55749	Hardin Generator Project	Big Horn	MT	0.05
55856	Prairie State Generatng Station ^(a)	St Clair	IL	0.30
56068	Elm Road Generating Station ^(g)	Milwaukee	WI	0.04
56224	TS Power Plant ^(p)	Eureka	NV	0.26
56319	Wygen 2 ^(k)	Campbell	WY	0.11
56456	Plum Point Energy Station ^(c)	Mississippi	AR	0.59
56564	John W Turk Jr Power Plant ⁽ⁿ⁾	HEMPSTEAD	AR	0.06
56596	Wygen III ^(k)	CAMPBELL	WY	0.11
56609	Dry Fork Station ^(k)	Campbell	WY	0.11
56671	Longview Power LLC ^(e)	Monongalia	WV	0.05
56808	Virginia City Hybrid Energy Center ^(d)	Wise	VA	0.14
56848	Haverhill North Cogeneration Facility ⁽ⁱ⁾	Scioto	OH	0.08
68029	AES Puerto Rico Cogeneration Facility ^(r)		PR	N/A

(a) Based on close proximity to survey of plant 10640.

(b) Based on close proximity to survey of plant 2709.

(c) Based on close proximity to survey of plant 3393.

(d) Based on close proximity to survey of plant 3775.

(e) Based on close proximity to survey of plant 3943.

(f) Based on close proximity to survey of plant 3992.

Exhibit L-2: Seismic Impact Data Listed by Plant				
Plant ID	Plant Name	County	State	Peak Ground Acceleration (g)
(g) Based on close proximity to survey of plant 4041. (h) Based on close proximity to survey of plant 470. (i) Based on close proximity to survey of plant 6031. (j) Based on close proximity to survey of plant 6077. (k) Based on close proximity to survey of plant 6101. (m) Based on close proximity to survey of plant 7030. (n) Based on close proximity to survey of plant 7902. (p) Based on close proximity to survey of plant 8224. (q) Based on close proximity to survey of plant 889. (r) This site was not surveyed.				

Exhibit L-3
Karst Data Listed by Plant

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
3	Mobile	AL	Barry			
7	Etowah	AL	Gadsden	long_2	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in moderately to steeply dipping beds of carbonate rock	100%
8	Walker	AL	Gorgas			
10	Greene	AL	Greene County			
26	Shelby	AL	E C Gaston	long_2	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in moderately to steeply dipping beds of carbonate rock	100%
47	Colbert	AL	Colbert	long_3	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in gently dipping to flat-lying beds of carbonate rock	100%
50	Jackson	AL	Widows Creek	long_2	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in moderately to steeply dipping beds of carbonate rock	100%
51	De Soto	LA	Dolet Hills			
56	Washington	AL	Charles R Lowman			
59	Hall	NE	Platte	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
60	Adams	NE	Whelan Energy Center	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%

Exhibit L-3
Karst Data Listed by Plant

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
79	Fairbanks North Star	AK	Aurora Energy LLC Chena			
87	McKinley	NM	Escalante			
108	Finney	KS	Holcomb			
113	Navajo	AZ	Cholla			
126	Pima	AZ	H Wilson Sundt Generating Station			
127	Wilbarger	TX	Oklaunion			
130	Berkeley	SC	Cross	short_4	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock	100%
136	Putnam	FL	Seminole	long_4	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
160	Cochise	AZ	Apache Station			
165	Mayes	OK	GRDA	long_3	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in gently dipping to flat-lying beds of carbonate rock	100%
207	Duval	FL	St Johns River Power Park	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	97%
298	Limestone	TX	Limestone			

Exhibit L-3
Karst Data Listed by Plant

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
384	Will	IL	Joliet 29	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
462	Fremont	CO	W N Clark	long_2	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in moderately to steeply dipping beds of carbonate rock	29%
465	Denver	CO	Arapahoe			
469	Adams	CO	Cherokee			
470	Pueblo	CO	Comanche			
477	Boulder	CO	Valmont			
492	El Paso	CO	Martin Drake	long_2	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in moderately to steeply dipping beds of carbonate rock	39%
508	Prowers	CO	Lamar Plant ⁽ⁱ⁾			
525	Routt	CO	Hayden			
527	Montrose	CO	Nucla			
564	Orange	FL	Stanton Energy Center	long_4	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
568	Fairfield	CT	Bridgeport Station			
594	Sussex	DE	Indian River Generating Station			
602	Anne Arundel	MD	Brandon Shores			

Exhibit L-3
Karst Data Listed by Plant

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
628	Citrus	FL	Crystal River	long_3	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in gently dipping to flat-lying beds of carbonate rock	99%
641	Escambia	FL	Crist			
642	Jackson	FL	Scholz	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
643	Bay	FL	Lansing Smith	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	74%
645	Hillsborough	FL	Big Bend	long_3	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in gently dipping to flat-lying beds of carbonate rock	51%
663	Alachua	FL	Deerhaven Generating Station	long_4	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
667	Duval	FL	Northside Generating Station	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	97%

Exhibit L-3
Karst Data Listed by Plant

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
676	Polk	FL	C D McIntosh Jr	long_3	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in gently dipping to flat-lying beds of carbonate rock	100%
703	Bartow	GA	Bowen	long_2	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in moderately to steeply dipping beds of carbonate rock	100%
708	Floyd	GA	Hammond			
709	Putnam	GA	Harllee Branch			
710	Cobb	GA	Jack McDonough			
727	Dougherty	GA	Mitchell	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
728	Coweta	GA	Yates			
733	Chatham	GA	Kraft	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
753	Worth	GA	Crisp Plant	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
856	Peoria	IL	E D Edwards			
861	Montgomery	IL	Coffeen			

**Exhibit L-3
Karst Data Listed by Plant**

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
867	Cook	IL	Crawford	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
874	Will	IL	Joliet 9	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
876	Christian	IL	Kincaid Generation LLC			
879	Tazewell	IL	Powerton			
883	Lake	IL	Waukegan	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	61%
884	Will	IL	Will County	short_4	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock	100%
886	Cook	IL	Fisk Street	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
887	Massac	IL	Joppa Steam			
889	Randolph	IL	Baldwin Energy Complex			
891	Mason	IL	Havana			

**Exhibit L-3
Karst Data Listed by Plant**

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
892	Putnam	IL	Hennepin Power Station			
898	Madison	IL	Wood River	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	90%
963	Sangamon	IL	Dallman			
976	Williamson	IL	Marion			
981	Lake	IN	State Line Energy	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	59%
983	Jefferson	IN	Clifty Creek	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
988	Dearborn	IN	Tanners Creek	short_4	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock	100%
990	Marion	IN	Harding Street			
991	Morgan	IN	Eagle Valley			
992	Marion	IN	CC Perry K			
994	Pike	IN	AES Petersburg			
995	Porter	IN	Bailly			
997	La Porte	IN	Michigan City			
1001	Vermillion	IN	Cayuga			

Exhibit L-3
Karst Data Listed by Plant

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
1004	Knox	IN	Edwardsport			
1008	Floyd	IN	R Gallagher			
1010	Vigo	IN	Wabash River			
1012	Warrick	IN	F B Culley			
1024	Montgomery	IN	Crawfordsville			
1032	Cass	IN	Logansport	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	17%
1037	Miami	IN	Peru			
1040	Wayne	IN	Whitewater Valley	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
1043	Pike	IN	Frank E Ratts			
1046	Dubuque	IA	Dubuque			
1047	Allamakee	IA	Lansing	short_4	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock	38%
1048	Clinton	IA	Milton L Kapp	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%

Exhibit L-3
Karst Data Listed by Plant

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
1073	Linn	IA	Prairie Creek	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
1077	Marshall	IA	Sutherland	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
1081	Scott	IA	Riverside	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
1082	Pottawattamie	IA	Walter Scott Jr Energy Center	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	45%
1091	Woodbury	IA	George Neal North			
1104	Des Moines	IA	Burlington			
1122	Story	IA	Ames Electric Services Power Plant	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%

**Exhibit L-3
Karst Data Listed by Plant**

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
1131	Black Hawk	IA	Streeter Station	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
1167	Muscatine	IA	Muscatine Plant #1	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
1175	Marion	IA	Pella	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	10%
1217	Clay	IA	Earl F Wisdom			
1239	Cherokee	KS	Riverton	long_3	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in gently dipping to flat-lying beds of carbonate rock	51%
1241	Linn	KS	La Cygne			
1250	Douglas	KS	Lawrence Energy Center			
1252	Shawnee	KS	Tecumseh Energy Center			
1295	Wyandotte	KS	Quindaro			
1353	Lawrence	KY	Big Sandy			
1355	Mercer	KY	E W Brown	long_3	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in gently dipping to flat-lying beds of carbonate rock	100%

**Exhibit L-3
Karst Data Listed by Plant**

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
1356	Carroll	KY	Ghent	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
1357	Muhlenberg	KY	Green River			
1361	Woodford	KY	Tyrone	long_3	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in gently dipping to flat-lying beds of carbonate rock	100%
1363	Jefferson	KY	Cane Run			
1364	Jefferson	KY	Mill Creek			
1374	Daviess	KY	Elmer Smith			
1378	Muhlenberg	KY	Paradise			
1379	McCracken	KY	Shawnee			
1381	Hancock	KY	Kenneth C Coleman			
1382	Henderson	KY	HMP&L Station Two Henderson			
1383	Webster	KY	Robert A Reid			
1384	Pulaski	KY	Cooper	long_3	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in gently dipping to flat-lying beds of carbonate rock	16%
1385	Clark	KY	Dale	long_3	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in gently dipping to flat-lying beds of carbonate rock	100%
1393	Calcasieu	LA	R S Nelson			
1552	Baltimore	MD	C P Crane			
1554	Anne Arundel	MD	Herbert A Wagner			

Exhibit L-3
Karst Data Listed by Plant

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
1570	Washington	MD	FirstEnergy R Paul Smith Power Station	short_3	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; in moderately to steeply dipping beds of carbonate rock	55%
1571	Prince Georges	MD	Chalk Point LLC			
1572	Montgomery	MD	Dickerson	short_1	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; in metamorphosed limestone, dolostone, and marble	71%
1573	Charles	MD	Morgantown Generating Plant			
1606	Hampden	MA	Mount Tom			
1619	Bristol	MA	Brayton Point			
1626	Essex	MA	Salem Harbor			
1695	Muskegon	MI	B C Cobb			
1702	Bay	MI	Dan E Karn			
1710	Ottawa	MI	J H Campbell			
1720	Bay	MI	J C Weadock			
1723	Monroe	MI	J R Whiting	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	62%
1731	Huron	MI	Harbor Beach			
1733	Monroe	MI	Monroe	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	53%

Exhibit L-3
Karst Data Listed by Plant

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
1740	Wayne	MI	River Rouge	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	50%
1743	St Clair	MI	St Clair			
1745	Wayne	MI	Trenton Channel	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	53%
1769	Marquette	MI	Presque Isle			
1771	Delta	MI	Escanaba	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	52%
1825	Ottawa	MI	J B Sims			
1830	Ottawa	MI	James De Young			
1831	Ingham	MI	Eckert Station			
1832	Eaton	MI	Erickson Station			
1843	Marquette	MI	Shiras			
1866	Wayne	MI	Wyandotte	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	47%
1891	St Louis	MN	Syl Laskin			

Exhibit L-3
Karst Data Listed by Plant

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
1893	Itasca	MN	Clay Boswell			
1897	St Louis	MN	M L Hibbard			
1904	Dakota	MN	Black Dog	short_4	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock	100%
1915	Washington	MN	Allen S King	short_4	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock	47%
1943	Otter Tail	MN	Hoot Lake			
1961	Mower	MN	Austin Northeast	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
1979	St Louis	MN	Hibbing			
2008	Olmsted	MN	Silver Lake	short_4	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock	51%
2018	St Louis	MN	Virginia			
2022	Kandiyohi	MN	Willmar			
2049	Harrison	MS	Jack Watson			
2062	Leflore	MS	Henderson			
2076	Jasper	MO	Asbury			
2079	Jackson	MO	Hawthorn	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m)	19%

Exhibit L-3
Karst Data Listed by Plant

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
					thick	
2080	Henry	MO	Montrose			
2094	Jackson	MO	Sibley			
2098	Buchanan	MO	Lake Road			
2103	Franklin	MO	Labadie	long_3	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in gently dipping to flat-lying beds of carbonate rock	1%
2104	St Louis	MO	Meramec	long_3	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in gently dipping to flat-lying beds of carbonate rock	100%
2107	St Charles	MO	Sioux	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	4%
2123	Boone	MO	Columbia			
2132	Jackson	MO	Blue Valley			
2144	Saline	MO	Marshall	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
2161	Greene	MO	James River Power Station	short_4	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock	100%

**Exhibit L-3
Karst Data Listed by Plant**

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
2167	New Madrid	MO	New Madrid			
2168	Randolph	MO	Thomas Hill			
2169	Osage	MO	Chamois	short_4	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock	99%
2171	Clay	MO	Missouri City			
2187	Yellowstone	MT	J E Corette Plant			
2240	Dodge	NE	Lon Wright			
2277	Lancaster	NE	Sheldon			
2291	Douglas	NE	North Omaha			
2324	Clark	NV	Reid Gardner			
2364	Merrimack	NH	Merrimack			
2367	Rockingham	NH	Schiller			
2378	Cape May	NJ	B L England			
2403	Hudson	NJ	PSEG Hudson Generating Station			
2408	Mercer	NJ	PSEG Mercer Generating Station			
2434	Cumberland	NJ	Howard Down			
2442	San Juan	NM	Four Corners			
2451	San Juan	NM	San Juan			
2468	Story	NM	Raton ^(g)			
2527	Yates	NY	GMMGreenidge LLC	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%

Exhibit L-3 Karst Data Listed by Plant						
Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
2535	Tompkins	NY	Cayuga Operating Company	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	0%
2549	Erie	NY	C R Huntley Generating Station	short_7	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; in gently dipping to flat-lying beds of gypsum	44%
2554	Chautauqua	NY	Dunkirk Generating Plant			
2682	Chautauqua	NY	S A Carlson			
2706	Buncombe	NC	Asheville			
2708	Chatham	NC	Cape Fear			
2709	Wayne	NC	HF Lee Plant			
2712	Person	NC	Roxboro			
2713	New Hanover	NC	L V Sutton Steam	short_4	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock	100%
2718	Gaston	NC	G G Allen			
2720	Rowan	NC	Buck			
2721	Cleveland	NC	Cliffside			
2727	Catawba	NC	Marshall			
2732	Gaston	NC	Riverbend			
2790	Morton	ND	R M Heskett			
2817	Mercer	ND	Leland Olds			
2823	Oliver	ND	Milton R Young			
2824	Mercer	ND	Stanton			
2828	Jefferson	OH	Cardinal			

Exhibit L-3
Karst Data Listed by Plant

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
2830	Clermont	OH	Walter C Beckjord	short_4	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock	100%
2832	Hamilton	OH	Miami Fort	short_4	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock	100%
2835	Ashtabula	OH	FirstEnergy Ashtabula			
2836	Lorain	OH	Avon Lake			
2837	Lake	OH	FirstEnergy Eastlake			
2838	Cuyahoga	OH	FirstEnergy Lake Shore			
2840	Coshocton	OH	Conesville			
2843	Pickaway	OH	Picway			
2848	Montgomery	OH	O H Hutchings			
2850	Adams	OH	J M Stuart	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	41%
2861	Trumbull	OH	Niles			
2866	Jefferson	OH	FirstEnergy W H Sammis			
2872	Washington	OH	Muskingum River			
2876	Gallia	OH	Kyger Creek			
2878	Lucas	OH	FirstEnergy Bay Shore	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	71%

Exhibit L-3 Karst Data Listed by Plant						
Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
2914	Tuscarawas	OH	Dover			
2917	Butler	OH	Hamilton			
2935	Wayne	OH	Orrville			
2936	Lake	OH	Painesville			
2943	Richland	OH	Shelby Municipal Light Plant			
2952	Muskogee	OK	Muskogee			
2963	Rogers	OK	Northeastern	short_4	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock	94%
3098	Washington	PA	Elrama Power Plant	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
3113	Northampton	PA	Portland	short_3	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; in moderately to steeply dipping beds of carbonate rock	12%
3115	Berks	PA	Titus	short_3	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; in moderately to steeply dipping beds of carbonate rock	50%
3118	Indiana	PA	Conemaugh			
3122	Indiana	PA	Homer City Station			
3130	Indiana	PA	Seward			
3131	Clearfield	PA	Shawville			
3136	Armstrong	PA	Keystone			

Exhibit L-3
Karst Data Listed by Plant

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
3138	Lawrence	PA	New Castle Plant	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
3140	York	PA	PPL Brunner Island			
3149	Montour	PA	PPL Montour	long_2	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in moderately to steeply dipping beds of carbonate rock	100%
3152	Snyder	PA	Sunbury Generation LP	long_2	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in moderately to steeply dipping beds of carbonate rock	100%
3178	Armstrong	PA	FirstEnergy Armstrong Power Station	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
3179	Greene	PA	Hatfields Ferry Power Station	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	46%
3181	Washington	PA	FirstEnergy Mitchell Power Station	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
3251	Darlington	SC	H B Robinson			

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Karst Data Listed by Plant**

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
3264	Anderson	SC	W S Lee			
3280	Colleton	SC	Canadys Steam	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
3287	Lexington	SC	McMeekin			
3295	Aiken	SC	Urquhart			
3297	Richland	SC	Wateree			
3298	Berkeley	SC	Williams	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
3319	Berkeley	SC	Jefferies	short_4	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock	100%
3325	Pennington	SD	Ben French	long_2	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in moderately to steeply dipping beds of carbonate rock	55%
3393	Shelby	TN	Allen Steam Plant			
3396	Anderson	TN	Bull Run			
3399	Stewart	TN	Cumberland	short_4	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock	100%
3403	Sumner	TN	Gallatin	long_3	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in gently dipping to flat-lying beds of	100%

Exhibit L-3
Karst Data Listed by Plant

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
					carbonate rock	
3405	Hawkins	TN	John Sevier	long_2	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in moderately to steeply dipping beds of carbonate rock	100%
3406	Humphreys	TN	Johnsonville	short_4	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock	2%
3407	Roane	TN	Kingston	long_2	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in moderately to steeply dipping beds of carbonate rock	100%
3470	Fort Bend	TX	W A Parish			
3497	Freestone	TX	Big Brown			
3644	Carbon	UT	Carbon			
3775	Russell	VA	Clinch River	long_2	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in moderately to steeply dipping beds of carbonate rock	100%
3776	Giles	VA	Glen Lyn	long_2	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in moderately to steeply dipping beds of carbonate rock	100%
3788	Alexandria	VA	Potomac River			
3796	Fluvanna	VA	Bremo Bluff			
3797	Chesterfield	VA	Chesterfield			
3803	Chesapeake	VA	Chesapeake			
3809	York	VA	Yorktown			
3845	Lewis	WA	TransAlta Centralia Generation			

Exhibit L-3
Karst Data Listed by Plant

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
3935	Putnam	WV	John E Amos			
3936	Kanawha	WV	Kanawha River			
3938	Mason	WV	Philip Sporn			
3942	Preston	WV	FirstEnergy Albright	short_4	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock	80%
3943	Monongalia	WV	FirstEnergy Fort Martin Power Station	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	51%
3944	Harrison	WV	FirstEnergy Harrison Power Station			
3945	Marion	WV	FirstEnergy Rivesville			
3946	Pleasants	WV	FirstEnergy Willow Island			
3947	Marshall	WV	Kammer			
3948	Marshall	WV	Mitchell			
3954	Grant	WV	Mt Storm			
3982	Ashland	WI	Bay Front			
4041	Milwaukee	WI	South Oak Creek	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	50%
4042	Milwaukee	WI	Valley	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m)	97%

Exhibit L-3
Karst Data Listed by Plant

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
					thick	
4050	Sheboygan	WI	Edgewater	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	54%
4054	Grant	WI	Nelson Dewey Coal Refining Facility	short_4	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock	98%
4057	Rock	WI	Rock River ^(e)			
4072	Brown	WI	Pulliam	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	48%
4078	Marathon	WI	Weston			
4125	Manitowoc	WI	Manitowoc	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	50%
4140	Buffalo	WI	Alma			
4143	Vernon	WI	Genoa			
4150	Campbell	WY	Neil Simpson			
4158	Converse	WY	Dave Johnston			
4162	Lincoln	WY	Naughton			

Exhibit L-3
Karst Data Listed by Plant

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
4259	Hillsdale	MI	Endicott Station			
4271	Buffalo	WI	John P Madgett			
4941	Coconino	AZ	Navajo			
6002	Jefferson	AL	James H Miller Jr			
6004	Pleasants	WV	FirstEnergy Pleasants Power Station			
6009	Jefferson	AR	White Bluff			
6016	Fulton	IL	Duck Creek			
6017	Jasper	IL	Newton			
6018	Boone	KY	East Bend	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
6019	Clermont	OH	W H Zimmer	short_4	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock	100%
6021	Moffat	CO	Craig			
6030	McLean	ND	Coal Creek			
6031	Adams	OH	Killen Station			
6034	St Clair	MI	Belle River			
6041	Mason	KY	H L Spurlock	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
6052	Heard	GA	Wansley			
6055	Pointe Coupee	LA	Big Cajun 2			

Exhibit L-3
Karst Data Listed by Plant

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
6061	Lamar	MS	R D Morrow			
6064	Wyandotte	KS	Nearman Creek			
6065	Platte	MO	Iatan			
6068	Pottawatomie	KS	Jeffrey Energy Center			
6071	Trimble	KY	Trimble County	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
6073	Jackson	MS	Victor J Daniel Jr			
6076	Rosebud	MT	Colstrip			
6077	Lincoln	NE	Gerald Gentleman			
6082	Niagara	NY	Somerset Operating Co LLC			
6085	Jasper	IN	R M Schahfer			
6089	Richland	MT	Lewis & Clark			
6090	Sherburne	MN	Sherburne County			
6094	Beaver	PA	FirstEnergy Bruce Mansfield			
6095	Noble	OK	Sooner	short_4	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock	86%
6096	Otoe	NE	Nebraska City			
6098	Grant	SD	Big Stone			
6101	Campbell	WY	Wyodak			
6106	Morrow	OR	Boardman			
6113	Gibson	IN	Gibson			

Exhibit L-3
Karst Data Listed by Plant

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
6124	Effingham	GA	McIntosh	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
6136	Grimes	TX	Gibbons Creek			
6137	Posey	IN	A B Brown			
6138	Benton	AR	Flint Creek	long_3	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in gently dipping to flat-lying beds of carbonate rock	100%
6139	Titus	TX	Welsh			
6146	Rusk	TX	Martin Lake			
6147	Titus	TX	Monticello			
6155	Jefferson	MO	Rush Island	long_3	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in gently dipping to flat-lying beds of carbonate rock	100%
6165	Emery	UT	Hunter			
6166	Spencer	IN	Rockport			
6170	Kenosha	WI	Pleasant Prairie	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
6177	Apache	AZ	Coronado			
6178	Goliad	TX	Coletto Creek			
6179	Fayette	TX	Fayette Power Project			
6180	Robertson	TX	Oak Grove ^(k)			

Exhibit L-3
Karst Data Listed by Plant

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
6181	Bexar	TX	J T Deely			
6183	Atascosa	TX	San Miguel			
6190	Rapides	LA	Brame Energy Center			
6193	Potter	TX	Harrington	pseudo_1	Fissures and voids present to a depth of 250 ft (75 m) or more in areas of subsidence from piping in thick, unconsolidated material	100%
6194	Lamb	TX	Tolk	pseudo_1	Fissures and voids present to a depth of 250 ft (75 m) or more in areas of subsidence from piping in thick, unconsolidated material	55%
6195	Greene	MO	John Twitty Energy Center	long_3	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in gently dipping to flat-lying beds of carbonate rock	25%
6204	Platte	WY	Laramie River Station			
6213	Sullivan	IN	Merom			
6225	Dubois	IN	Jasper 2			
6238	Pike	IL	Pearl Station	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
6248	Morgan	CO	Pawnee			
6249	Georgetown	SC	Winyah			
6250	Person	NC	Mayo			
6254	Wapello	IA	Ottumwa	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	58%
6257	Monroe	GA	Scherer			

Exhibit L-3 Karst Data Listed by Plant						
Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
6264	Mason	WV	Mountaineer			
6288	Denali Borough	AK	Healy			
6469	Mercer	ND	Antelope Valley			
6481	Millard	UT	Intermountain Power Project			
6639	Webster	KY	R D Green			
6641	Independence	AR	Independence			
6648	Milam	TX	Sadow No 4			
6664	Louisa	IA	Louisa			
6705	Warrick	IN	Warrick			
6761	Larimer	CO	Rawhide			
6768	Scott	MO	Sikeston Power Station			
6772	Choctaw	OK	Hugo	short_4	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock	16%
6823	Ohio	KY	D B Wilson			
7030	Robertson	TX	Twin Oaks Power One			
7097	Bexar	TX	J K Spruce			
7210	Orangeburg	SC	Cope	short_4	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock	100%
7213	Halifax	VA	Clover			
7242	Polk	FL	Polk	long_4	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%

Exhibit L-3 Karst Data Listed by Plant						
Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
7343	Woodbury	IA	George Neal South			
7504	Campbell	WY	Neil Simpson II			
7537	Grant	WV	North Branch	short_4	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock	25%
7549	Milwaukee	WI	Milwaukee County	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
7652	Aiken	SC	US DOE Savannah River Site (D Area)			
7790	Uintah	UT	Bonanza			
7902	Harrison	TX	Pirkey			
8023	Columbia	WI	Columbia			
8042	Stokes	NC	Belews Creek			
8066	Sweetwater	WY	Jim Bridger			
8069	Emery	UT	Huntington			
8102	Gallia	OH	General James M Gavin			
8219	El Paso	CO	Ray D Nixon			
8222	Mercer	ND	Coyote			
8223	Apache	AZ	Springerville			
8224	Humboldt	NV	North Valmy			
8226	Allegheny	PA	Cheswick Power Plant			
10002	San Bernardino	CA	ACE Cogeneration Facility			

Exhibit L-3
Karst Data Listed by Plant

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
10003	Jefferson	CO	Colorado Energy Nations Company	long_5	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in moderately to steeply dipping beds of gypsum	23%
10030	Kent	DE	NRG Energy Center Dover			
10043	Gloucester	NJ	Logan Generating Company LP			
10071	Portsmouth City	VA	Portsmouth Genco LLC			
10075	Cook	MN	Taconite Harbor Energy Center			
10113	Schuylkill	PA	John B Rich Memorial Power Station			
10143	Cambria	PA	Colver Power Project			
10148	Ontonagon	MI	White Pine Electric Power			
10151	Marion	WV	Grant Town Power Plant	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
10343	Northumberland	PA	Foster Wheeler Mt Carmel Cogen			
10367	Contra Costa	CA	East Third Street Power Plant ^(a)			
10369	Contra Costa	CA	Wilbur West Power Plant ^(a)			
10370	Contra Costa	CA	Wilbur East Power Plant ^(a)			
10371	Contra Costa	CA	Nichols Road Power Plant ^(a)			
10377	City of Hopewell	VA	James River Genco LLC			
10378	Brunswick	NC	CPI USA NC Southport			
10379	Person	NC	CPI USA NC Roxboro			

Exhibit L-3
Karst Data Listed by Plant

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
10380	Bladen	NC	Elizabethtown Power LLC			
10381	Duplin	NC	Coastal Carolina Clean Power			
10384	Edgecombe	NC	Edgecombe Genco LLC			
10464	Jefferson	NY	Black River Generation	short_4	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock	100%
10495	Oxford	ME	Rumford Cogeneration			
10566	Salem	NJ	Chambers Cogeneration LP			
10603	Cambria	PA	Ebensburg Power			
10604	Maui	HI	Hawaiian Comm & Sugar Puunene Mill			
10640	San Joaquin	CA	Stockton Cogen			
10641	Cambria	PA	Cambria Cogen			
10671	Leflore	OK	AES Shady Point LLC			
10672	Duval	FL	Cedar Bay Generating Company LP	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	56%
10673	Oahu	HI	AES Hawaii			
10676	Beaver	PA	AES Beaver Valley Partners Beaver Valley			
10678	Allegany	MD	AES Warrior Run Cogeneration Facility	long_2	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in moderately to steeply dipping beds of carbonate rock	1
10686	Itasca	MN	Rapids Energy Center			
10743	Monongalia	WV	Morgantown Energy Facility			

Exhibit L-3 Karst Data Listed by Plant						
Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
10768	Kern	CA	Rio Bravo Jasmin			
10769	Kern	CA	Rio Bravo Poso			
10771	Hopewell City	VA	Hopewell Power Station			
10774	Southampton	VA	Southampton Power Station			
10784	Rosebud	MT	Colstrip Energy LP			
50039	Schuylkill	PA	Kline Township Cogen Facility			
50202	Niagara	NY	WPS Power Niagara	short_4	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock	100%
50407	Mobile	AL	Mobile Energy Services LLC			
50611	Schuylkill	PA	Westwood Generation LLC			
50651	Onondaga	NY	Syracuse Energy			
50776	Carbon	PA	Panther Creek Energy Facility			
50835	Manistee	MI	TES Filer City Station			
50879	Schuylkill	PA	Wheelabrator Frackville Energy			
50888	Northampton	PA	Northampton Generating Company LP	short_3	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; in moderately to steeply dipping beds of carbonate rock	100%
50951	Carbon	UT	Sunnyside Cogen Associates			
50974	Venango	PA	Scrubgrass Generating Company LP	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	4%

Exhibit L-3
Karst Data Listed by Plant

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
50976	Martin	FL	Indiantown Cogeneration LP	short_4	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock	100%
52007	Mecklenburg	VA	Mecklenburg Power Station			
54035	Halifax	NC	Roanoke Valley Energy Facility I			
54081	City of Richmond	VA	Spruance Genco LLC			
54144	Clarion	PA	Piney Creek Project	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	100%
54304	King George	VA	Birchwood Power			
54634	Schuylkill	PA	St Nicholas Cogen Project			
54755	Halifax	NC	Roanoke Valley Energy Facility II			
55076	Choctaw	MS	Red Hills Generating Facility			
55245	Douglas	IL	Tuscola Station			
55479	Campbell	WY	Wygen 1			
55749	Big Horn	MT	Hardin Generator Project			
55856	St Clair	IL	Prairie State Generating Station ^(p)			
56068	Milwaukee	WI	Elm Road Generating Station ^(f)	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	50%
56224	Eureka	NV	TS Power Plant ⁽ⁿ⁾			

Exhibit L-3
Karst Data Listed by Plant

Plant ID	County	State	Plant Name	Karst Type	Karst Description	% of 2 km area
56319	Campbell	WY	Wygen 2 ^(j)			
56456	Mississippi	AR	Plum Point Energy Station ^(b)			
56564	HEMPSTEAD	AR	John W Turk Jr Power Plant ^(m)			
56596	CAMPBELL	WY	Wygen III ^(j)			
56609	Campbell	WY	Dry Fork Station ^(j)			
56671	Monongalia	WV	Longview Power LLC ^(d)	short_5	Fissures, tubes and caves generally less than 1,000 ft (300 m) long; 50 ft (15 m) or less vertical extent; In gently dipping to flat-lying beds of carbonate rock beneath an overburden of noncarbonate material 10 ft (3 m) to 200 ft (60 m) thick	51%
56808	Wise	VA	Virginia City Hybrid Energy Center ^(c)	long_2	Fissures, tubes, and caves over 1,000 ft (300 m) long; 50 ft (15 m) to over 250 ft (75 m) vertical extent; in moderately to steeply dipping beds of carbonate rock	100%
56848	Scioto	OH	Haverhill North Cogeneration Facility ^(h)			
68029		PR	AES Puerto Rico Cogeneration Facility ^(r)	N/A	N/A	N/A

Notes:

- (a) Based on close proximity to survey of plant 10640.
- (b) Based on close proximity to survey of plant 3393.
- (c) Based on close proximity to survey of plant 3775.
- (d) Based on close proximity to survey of plant 3943.
- (e) Based on close proximity to survey of plant 3992.
- (f) Based on close proximity to survey of plant 4041.
- (g) Based on close proximity to survey of plant 470.
- (h) Based on close proximity to survey of plant 6031.
- (i) Based on close proximity to survey of plant 6077.
- (j) Based on close proximity to survey of plant 6101.
- (k) Based on close proximity to survey of plant 7030.
- (m) Based on close proximity to survey of plant 7902.
- (n) Based on close proximity to survey of plant 8224.
- (p) Based on close proximity to survey of plant 889.
- (r) This site was not surveyed.

APPENDIX M

RCRA Subtitle D Paperwork Reporting/Recordkeeping Unit Cost Estimates

Note: While all cost equations presented in this appendix are in 2011\$, they have been inflated to 2013\$ using the Engineering News Record Construction Cost Index for use in this RIA.

The following table details the set of 61 paperwork reporting and/or recordkeeping activities that would be required for CCR management units or coal-fired electric utility plants with CCR management units under the RCRA Subtitle D requirements of the CCR final rule. Where appropriate, this RIA assumes that each activity would occur as many times as possible over the 100-year period of analysis, and does not attempt to distinguish in cases where certain requirements would preclude the applicability of other requirements (though it does acknowledge where the costs associated with certain requirements overlap and does not double-count these instances). As a conservatism, and because reporting/recordkeeping costs are low, this RIA does not apply certain reporting/recordkeeping costs only to the specific CCR management units to which they may apply; for example, location restriction demonstration requirements are assumed to apply to all CCR management units even though relatively few units are located in zones requiring location restriction demonstrations.

Each unit cost for each activity is annualized and amortized as appropriate, based on the most frequent timing with which it can be assumed to occur. Then, this RIA constructs three distinct categories of paperwork reporting/recordkeeping costs: 1) those applicable to all CCR management units; 2) those only applicable to on-site landfills; and, 3) those only applicable to on-site surface impoundments (both disposal and storage). Each of the 1,045 on-site CCR management units incurs the annualized cost associated with 1), and additionally the 310 landfills incur the annualized cost associated with 2) while the 735 impoundments incur the annualized cost associated with 3). As a conservatism, this RIA does not attempt to factor in economies of scale or cost savings for reporting and recordkeeping activities for multiple CCR management units at the same facility. As a result, total recordkeeping costs presented below and in this RIA are likely to overestimate actual compliance costs for reporting and recordkeeping activities.

Wage rates presented below are from the May 2011 National Occupational Employment and Wage Estimates, United States, June 2010. Bureau of Labor Statistics. http://www.bls.gov/oes/current/oes_nat.htm. The mean hourly wage for each employment category was used.

Fringe rates included in the calculations below are from Employer Costs for Worker Compensation, released September 8, 2011. Table 10. Employer Costs per Hour Worked for Employee Compensation and Costs as a Percent of Total Compensation: Private Workers, by Industry Group, June 2011. Bureau of Labor Statistics. <http://www.bls.gov/news.release/ece.nr0.htm>.

Overhead rates included in the calculations below consist of a 12 percent overhead rate applied, consistent with inputs to the FORTRAN-based CCR cost model.

RCRA Subtitle D Paperwork Reporting/Recordkeeping Unit Cost Estimates

Item	Description	Applicability	Timing	Cost Type	Legal Hrs.	Managerial Hrs.	Technical Hrs.	Clerical Hrs.	O&M Cost	Total Cost	Annualized Cost 7 % (\$2011)	Annualized Cost 3 % (\$2011)	Cost Type	Data Source*	Notes
1	Demonstration that CCR surface impoundments that once received CCRs but have since been dewatered and serve as the base for a CCR landfill pose no risk of contamination to groundwater	SI	Once per 100 years	Modification - SI to new LF	0	1	16	3	\$3	\$1,133	\$94	\$55	Generic demonstration cost for SI	[2], 264.221 - Demonstrations and Exemptions from Requirements	
2	Demonstration that added environmental measures have been taken that are protective of human health and the environment for new CCR landfills, CCR surface impoundments, and lateral expansions located within 1000 feet of a private water supply or over unconsolidated aquifers capable of sustaining a yield greater than 100 gallons per minute.	All Units	3 times per 100 years	General	0	0	2	0.25	\$18	\$141	\$12	\$7		[1], 264.113(e) - Prepare and submit corrective action report	
3	Demonstrations for new CCR landfills, new or existing CCR surface impoundments, and lateral expansions in wetlands.	All Units	3 times per 100 years	General	0	0.25	1	0.75	\$0	\$110	\$9	\$5			
4	Demonstrations for new CCR landfills, new or existing CCR surface impoundments, and lateral expansions located within 200 feet (60 meters) of a fault.	All Units	3 times per 100 years	General	0	0.25	1	0.75	\$0	\$110	\$9	\$5		[2], 270.14 - Seismic Impact	
5	Demonstrations for new CCR landfills, new or existing CCR surface impoundments, and lateral expansions located in seismic impact zones.	All Units	3 times per 100 years	General	0	0.25	1	0.75	\$0	\$110	\$9	\$5		[2], 270.14 - General Facility Standards	
6	Demonstrations for new or existing CCR landfills, new or existing CCR surface impoundments and lateral expansions located in an unstable area.	All Units	3 times per 100 years	General	0	0.25	1	0.75	\$0	\$110	\$9	\$5			

RCRA Subtitle D Paperwork Reporting/Recordkeeping Unit Cost Estimates

Item	Description	Applicability	Timing	Cost Type	Legal Hrs.	Managerial Hrs.	Technical Hrs.	Clerical Hrs.	O&M Cost	Total Cost	Annualized Cost 7% (\$2011)	Annualized Cost 3% (\$2011)	Cost Type	Data Source*	Notes
7	Demonstration for the 2 year extension of the closure requirement in unstable areas.	All Units	3 times per 100 years	General	0	0.25	1	0.75	\$0	\$110	\$9	\$5			
8	Demonstration for alternative liners for new CCR landfills and lateral expansions	LF	3 times per 100 years	General	0	1	16	3	\$3	\$1,133	\$94	\$55	Generic demonstration cost for LF	[2], 264.221 - Demonstrations and Exemptions from Requirements	
9	Demonstrations for liners for existing CCR surface impoundments	SI	3 times per 100 years	General	0	1	16	3	\$3	\$1,133	\$97	\$57	Generic demonstration cost for SI	[2], 264.221 - Demonstrations and Exemptions from Requirements	
10	Demonstrations that existing surface impoundments meet a static structural stability safety factor	SI	3 times per 100 years	General	0	1	16	3	\$3	\$0	\$0	\$0	Generic demonstration cost for SI	[2], 264.221 - Demonstrations and Exemptions from Requirements	
11	Certification by an independent registered professional engineer that the design of the CCR surface impoundment is in accordance with current, prudent engineering practices.	SI	3 times per 100 years	General	0	0	3	0.5	\$340	\$529	\$44	\$26	Generic cost for engineer certification	[2], 270.17 - Certification from a qualified engineer	Includes Item 16
12	History of construction, and any record or knowledge of structural instability for existing surface impoundments.	SI	3 times per 100 years	General	0	0.5	20	3	\$0	\$0	\$0	\$0		[2], 270.17 - Develop Plans and Engineering Report	
13	An Emergency Action Plan for existing CCR surface impoundments classified as having a high or significant hazard potential.	SI	3 times per 100 years	General	0	4	30	5	\$1,000	\$3,329	\$276	\$163		[2] - 270.14 - Write a Contingency Plan	Includes Item 19
14	Demonstrations for the design of composite liners or alternative liners for new surface impoundments	SI	3 times per 100 years	General	0	1	16	3	\$3	\$1,133	\$94	\$55	Generic demonstration cost for SI	[2], 264.221 - Demonstrations and Exemptions from Requirements	Included in item 9

RCRA Subtitle D Paperwork Reporting/Recordkeeping Unit Cost Estimates

Item	Description	Applicability	Timing	Cost Type	Legal Hrs.	Managerial Hrs.	Technical Hrs.	Clerical Hrs.	O&M Cost	Total Cost	Annualized Cost 7% (\$2011)	Annualized Cost 3% (\$2011)	Cost Type	Data Source*	Notes
15	Demonstrations that existing surface impoundments meet a static structural stability safety factor	SI	3 times per 100 years	General	0	1	16	3	\$3	\$0	\$0	\$0	Generic demonstration cost for SI	[2], 264.221 - Demonstrations and Exemptions from Requirements	Included in item 10
16	Certification by an independent registered professional engineer that the design of the CCR surface impoundment or lateral expansion is in accordance with generally accepted engineering standards for the maximum volume of CCR slurry and CCR waste water which can be impounded.	SI	3 times per 100 years	General	0	0	3	0.5	\$340	\$529	\$584	\$584	Generic cost for engineer certification	[2], 270.17 - Certification from a qualified engineer	Included in Item 11
17	Notice that plans for the design, construction, and maintenance of new CCR surface impoundments and lateral expansions have been placed in the operating record and submitted to state.	SI	3 times per 100 years	General	0	0.5	0	0	\$3	\$58	\$66	\$66	Generic cost for notification in writing	[1], 264.223 - Notifying EPA in writing 0.5 hours manager	
18	Certification by an independent registered professional engineer for modifications to plans for the design, construction, and maintenance of new CCR surface impoundments.	SI	3 times per 100 years	Modification - New SI	0	0	3	0.5	\$340	\$529	\$41	\$18	Generic cost for engineer certification	[2], 270.17 - Certification from a qualified engineer	
19	Emergency Action Plan for new CCR surface impoundments classified by as having a high or significant hazard potential.	SI	3 times per 100 years	General	0	4	30	5	\$1,000	\$3,329	\$3,794	\$3,794		[2], 270.14 - Write a Contingency Plan	Included in Item 13

RCRA Subtitle D Paperwork Reporting/Recordkeeping Unit Cost Estimates

Item	Description	Applicability	Timing	Cost Type	Legal Hrs.	Managerial Hrs.	Technical Hrs.	Clerical Hrs.	O&M Cost	Total Cost	Annualized Cost 7% (\$2011)	Annualized Cost 3% (\$2011)	Cost Type	Data Source*	Notes
20	Fugitive dust control plan	All Units	3 times per 100 years	Dust Control	0	0	8	0.5	\$5,000	\$5,476	\$1,248	\$1,248	Contingent corrective action plan cost	[2], 265.113(e) - Prepare and submit contingent corrective measures plan	Closure corrective measures plan cost used as conservative proxy for dust control plan cost
21	Modifications to the fugitive dust control plan	All Units	3 times per 100 years	Dust Control	0	0	8	0.5	\$5,000	\$5,476	\$6,241	\$6,241	Contingent corrective action plan cost	[2], 265.113(e) - Prepare and submit contingent corrective measures plan	Assume same cost as item 20 for any modification to plan
22	Certifications of fugitive dust plans and modifications to fugitive dust plans by an independent qualified professional engineer	All Units	3 times per 100 years	Dust Control	0	0	3	0.5	\$340	\$529	\$44	\$26	Generic cost for engineer certification	[2], 270.17 - Certification from a qualified engineer	Certification from engineer used as conservative proxy

RCRA Subtitle D Paperwork Reporting/Recordkeeping Unit Cost Estimates

Item	Description	Applicability	Timing	Cost Type	Legal Hrs.	Managerial Hrs.	Technical Hrs.	Clerical Hrs.	O&M Cost	Total Cost	Annualized Cost 7% (\$2011)	Annualized Cost 3% (\$2011)	Cost Type	Data Source*	Notes
23	Notice of an incident where fugitive CCR dust exceeds the standards	All Units	As needed (annual ?)	Dust Control	0	0.5	0	0	\$3	\$58	\$5	\$3	Generic cost for notification in writing	[2], 264.223 - Notifying in writing	One-sixth of ALR exceedance notification cost used as conservative proxy
24	The design for run-on/run-off controls.	All Units	3 times per 100 years	Run-on/run-off	0	1	20	3	\$25,000	\$0	\$0	\$0		[2], 270.21 - Prepare plans and an engineering report describing landfill design, construction, operation and maintenance	Includes Item 25
25	Report showing how the run-on/run-off control systems meet the requirements.	All Units	3 times per 100 years	Run-on/run-off	0	1	20	3	\$25,000		\$0	\$0		[2], 270.21 - Prepare plans and an engineering report describing landfill design, construction, operation and maintenance	Included in Item 24
26	Certification by an independent registered professional engineer following annual inspections that the design, operation, and maintenance of surface impoundments is in accordance with generally accepted engineering standards.	SI	Annual cost	General	0	0	3	0.5	\$340	\$529	\$44	\$26	Generic cost for engineer certification	[2], 270.17 - Certification from a qualified engineer	

RCRA Subtitle D Paperwork Reporting/Recordkeeping Unit Cost Estimates

Item	Description	Applicability	Timing	Cost Type	Legal Hrs.	Managerial Hrs.	Technical Hrs.	Clerical Hrs.	O&M Cost	Total Cost	Annualized Cost 7% (\$2011)	Annualized Cost 3% (\$2011)	Cost Type	Data Source*	Notes
27	Annual report of all existing surface impoundments documenting changes in the geometry of the impounding structure for the reporting period, location and type of installed instruments and the maximum and minimum recorded readings of each instrument for the reporting period, the minimum, maximum, and present depth and elevation of the impounded water, sediment, or slurry for the reporting period, storage capacity of the impounding structure, the volume of the impounded water, sediment, or slurry at the end of the reporting period, any other change which may have affected the stability or operation of the impounding structure that has occurred during the reporting period, a certification by an independent registered professional engineer that all construction, operation, and maintenance were in accordance with the approved plan.	SI	Annual	General	1	1	2	1	\$5,000	\$5,392	\$6,146	\$6,146		[1], 265.221 and 265.222 -Prepare and submit written assessment of alternative design and operating practices to EPA or authorized State	
28	Report of weekly inspections and instrumentation monitoring.	All Units	Annual cost	General	0	0	72.5	0	\$0	\$4,161	\$4,591	\$4,591		[1], 264.226(d) - Record all inspection data	
29	Annual notification throughout the active life and post-closure care period that the CCR landfill or surface impoundment is in compliance with the groundwater monitoring and corrective action provisions.	All Units	Annual	Groundwater monitoring & corrective action	0	0.5	0	0	\$3	\$58	\$66	\$66	Generic cost for notification in writing	[1], 264.223 - Notifying EPA in writing 0.5 hours manager	

RCRA Subtitle D Paperwork Reporting/Recordkeeping Unit Cost Estimates

Item	Description	Applicability	Timing	Cost Type	Legal Hrs.	Managerial Hrs.	Technical Hrs.	Clerical Hrs.	O&M Cost	Total Cost	Annualized Cost 7% (\$2011)	Annualized Cost 3% (\$2011)	Cost Type	Data Source*	Notes
30	Documentation of groundwater monitoring system design, installation, development, and decommission of any monitoring wells, piezometers and other measurement, sampling, and analytical devices.	All Units	3 times per 100 years	Groundwater monitoring	0	10	251	12.7	\$93,316	\$0	\$0	\$0		[2], 270.14(c)(6) - General Groundwater Monitoring Requirements: Detection Monitoring Program	Includes item 32; may include item 33
31	Certification by an independent registered professional engineer or hydrologist of the number, spacing, and depths of monitoring systems.	All Units	3 times per 100 years	Groundwater monitoring	0	0	3	0.5	\$340	\$529	\$603	\$603	Generic cost for engineer certification	[2], 270.17 - Certification from a qualified engineer	May include item 33
32	Groundwater monitoring sampling and analysis program documentation.	All Units	3 times per 100 years	Groundwater monitoring	0	0	40	0	\$15,000		\$0	\$0		[2], 270.14(c)(1)-(5) - General Groundwater Monitoring Requirements	Included in Item 30
33	The statistical methods to be used in evaluating groundwater monitoring data for each hazardous constituent.	All Units	3 times per 100 years	Groundwater monitoring	0	0	3	0.5	\$0		\$209	\$209		[2], 270.14(c)(1)-(5) - Statistical Method	Included in Items 30 or 31
34	Justification for an alternative groundwater monitoring data statistical test method that meets the performance standards.	All Units	3 times per 100 years	Groundwater monitoring	0	0.5	3.5	1	\$10,000	\$10,290	\$852	\$503		[2], 270.14(o)(8) - Prepare description of how the groundwater monitoring program will demonstrate the adequacy of the corrective action	
35	A notice indicating which groundwater monitoring parameters, if any, have shown statistically significant changes from background levels.	All Units	As needed (annual ?)	Groundwater monitoring	0	0.5	0	0	\$3	\$58	\$0	\$0	Generic cost for notification in writing	[1], 264.223 - Notifying EPA in writing 0.5 hours manager	

RCRA Subtitle D Paperwork Reporting/Recordkeeping Unit Cost Estimates

Item	Description	Applicability	Timing	Cost Type	Legal Hrs.	Managerial Hrs.	Technical Hrs.	Clerical Hrs.	O&M Cost	Total Cost	Annualized Cost 7% (\$2011)	Annualized Cost 3% (\$2011)	Cost Type	Data Source*	Notes
36	Certification by an independent registered professional engineer or hydrologist of a demonstration that a source other than the CCR landfill or surface impoundment caused the statistically significant increase or that the statistically significant increase resulted from error in sampling, analysis, statistical evaluation, or natural variation in groundwater quality.	All Units	As needed (annual ?)	Groundwater monitoring	0	0	3	0.5	\$340	\$529	\$1	\$0	Generic cost for engineer certification	[2], 270.17 Certification from a qualified engineer	
37	A notice identifying the Appendix IV constituents that have been detected during assessment monitoring.	All Units	As needed (annual ?)	Groundwater monitoring	0	0.5	0	0	\$3	\$0	\$0	\$0	Generic cost for notification in writing	[1], 264.223 - Notifying EPA in writing 0.5 hours manager	
38	Semi-annual report of concentrations for all Appendix III & IV parameters detected during assessment monitoring.	All Units	Every 6 months	Groundwater monitoring	0	0	0	0	\$0		\$0	\$0			Included in groundwater monitoring costs
39	Notification if the concentrations of all Appendix IV constituents are shown to be at or below background values, using the selected statistical procedures for two consecutive sampling events during assessment monitoring.	All Units	As needed (annual ?)	Groundwater monitoring	0	0.5	0	0	\$3	\$58	\$0	\$0	Generic cost for notification in writing	[1], 264.223 - Notifying EPA in writing 0.5 hours manager	Used in lieu of Item 40
40	Notification if one or more Appendix IV constituents are detected at statistically significant levels above the established groundwater protection standard.	All Units	As needed (annual ?)	Groundwater monitoring	0	0.5	0	0	\$3		\$5	\$3	Generic cost for notification in writing	[1], 264.223 - Notifying EPA in writing 0.5 hours manager	Not used in lieu of Item 39

RCRA Subtitle D Paperwork Reporting/Recordkeeping Unit Cost Estimates

Item	Description	Applicability	Timing	Cost Type	Legal Hrs.	Managerial Hrs.	Technical Hrs.	Clerical Hrs.	O&M Cost	Total Cost	Annualized Cost 7% (\$2011)	Annualized Cost 3% (\$2011)	Cost Type	Data Source*	Notes
41	A report demonstrating that a source other than the CCR landfill or surface impoundment caused the contamination, or that the statistically significant increase resulted from error in sampling, analysis, statistical evaluation, or natural variation in groundwater quality.	All Units	As needed (annual ?)	Groundwater monitoring	0	4	12	0	\$800	\$1,925	\$165	\$97		[1], 265.223(c) - Remediation Determination Analysis	
42	Certification by an independent registered professional engineer of an alternative groundwater protection standard for constituents for which MCLs have not been established.	All Units	3 times per 100 years	Groundwater monitoring	0	0	3	0.5	\$340	\$529	\$44	\$26	Generic cost for engineer certification	[2], 270.17 - Certification from a qualified engineer	
43	Notification of the corrective measures assessment.	All Units	As needed (annual ?)	Corrective action	0	0.5	0	0	\$3	\$58	\$5	\$3	Generic cost for notification in writing	[1], 264.223 - Notifying EPA in writing 0.5 hours manager	
44	A report certified by an independent registered professional engineer or hydrologist describing the selected remedy.	All Units	As needed (annual ?)	Corrective action	0	7.5	53	6.25	\$90,000	\$94,073	\$8,049	\$4,752		[2], 270.14(o)(8) - Groundwater Corrective Action Program	Included in lieu of Items 45 and 46
45	A demonstration certified by an independent registered professional engineer or hydrologist that remediation of a release of an Appendix IV constituent from a CCR landfill or surface impoundment is not necessary	All Units	As needed (annual ?)	Corrective action	0	2	16	2			\$100	\$59		[2], 270.14(o) - Prepare Demonstration of Alternate Concentration Limits	Not included in lieu of Items 44 and 46
46	Certification by an independent registered professional engineer of alternative corrective action measures.	All Units	As needed (annual ?)	Corrective action	0	0	3	0.5	\$340		\$44	\$26	Generic cost for engineer certification	[2], 270.17 - Certification from a qualified engineer	Not included in lieu of Items 44 and 45

RCRA Subtitle D Paperwork Reporting/Recordkeeping Unit Cost Estimates

Item	Description	Applicability	Timing	Cost Type	Legal Hrs.	Managerial Hrs.	Technical Hrs.	Clerical Hrs.	O&M Cost	Total Cost	Annualized Cost 7% (\$2011)	Annualized Cost 3% (\$2011)	Cost Type	Data Source*	Notes
47	Certification by an independent registered professional engineer of the completion of corrective actions.	All Units	As needed (annual ?)	Corrective action	0	0	3	0.5	\$340	\$529	\$44	\$26	Generic cost for engineer certification	[2], 270.17 - Certification from a qualified engineer	Included because Item 44 is used
48	Closure plan certified by an independent registered professional engineer.	All Units	3 times per 100 years	Closure	0	4.5	44	10.75	\$12,800	\$0	\$0	\$0		[2], 270.14(b) - General Facility Standards	
49	Amended closure plan, if applicable	All Units	3 times per 100 years	Closure	8	18	96	15.6	\$25,018	\$34,096	\$2,824	\$1,667		[2], 270.42 - Permit Modifications at the Request of the Permittee	
50	Notification of intent to close.	All Units	3 times per 100 years	Closure	0	0.5	0	0	\$3	\$58	\$4	\$2	Generic cost for notification in writing	[1], 264.223 - Notifying EPA in writing 0.5 hours manager	
51	Certification of closure.	All Units	3 times per 100 years	Closure	0	0	0.5	1	\$343	\$406	\$34	\$20		[1], 264.280 - Obtain and submit certification	
52	Deed notation that the land has been used as a CCR landfill or CCR surface impoundment.	All Units	3 times per 100 years	Closure	0	0	0	0	\$1,000	\$1,000	\$83	\$49			
53	Certification by an independent registered professional engineer of a demonstration that a reduced post-closure period is sufficient.	All Units	3 times per 100 years	Closure	0	0	3	0.5	\$340	\$529	\$44	\$26	Generic cost for engineer certification	[2], 270.17 - Certification from a qualified engineer	
54	Demonstration that disturbance of the final cover, liner or other component of the containment system, including any removal of CCRs, from post-closure use will not increase the potential threat to human health or the environment.	All Units	3 times per 100 years	Closure	0	0	2	0.25	\$18	\$141	\$12	\$7		[1], 264.113(e) - Prepare and submit corrective action report	

RCRA Subtitle D Paperwork Reporting/Recordkeeping Unit Cost Estimates

Item	Description	Applicability	Timing	Cost Type	Legal Hrs.	Managerial Hrs.	Technical Hrs.	Clerical Hrs.	O&M Cost	Total Cost	Annualized Cost 7% (\$2011)	Annualized Cost 3% (\$2011)	Cost Type	Data Source*	Notes
55	Post-closure care plan.	All Units	3 times per 100 years	Closure	0	0	0	0	\$0		\$0	\$0		[2], 270.14(b) - General Facility Standards	Included in Item 48
56	Certification by an independent registered professional engineer, verifying that post-closure care has been completed in accordance with the post-closure plan.	All Units	3 times per 100 years	Closure	0	0	3	0.5	\$340	\$0	\$0	\$0	Generic cost for engineer certification	[2], 270.17 - Certification from a qualified engineer	
56	Notification that post-closure plan has been amended	All Units	3 times per 100 years	Closure	8	18	96	15.6	\$25,018	\$0	\$0	\$0		[2], 270.42 - Permit Modifications at the Request of the Permittee	Included in item 49
58	Certification by an independent registered engineer of the measures taken to comply with the air criteria.	All Units	3 times per 100 years	Dust Control	0	0	3	0.5	\$340	\$529	\$44	\$26	Generic cost for engineer certification	[2], 270.17 - Certification from a qualified engineer	
59	All records, reports, studies or other documentation required to demonstrate compliance with the criteria for location restrictions, design criteria, operating criteria, and groundwater monitoring.	All Units	Once per 100 years	General	0	0.5	20	3		\$1,305	\$108	\$64		[2], 270.17 - Develop Plans and Engineering Report	
60	Certification every 5 years by an independent registered professional engineer that there have been no changes to the surface impoundment.	SI	Every 5 years	Recurring - 5 years	0	0	3	0.5	\$340	\$529	\$44	\$26	Generic cost for engineer certification	[2], 270.17 - Certification from a qualified enginee	
61	Certification by an independent registered professional engineer of an alternative cover design.	All Units	3 times per 100 years	Closure	0	0	3	0.5	\$340	\$529	\$603	\$603	Generic cost for engineer certification	[2], 270.17 - Certification from a qualified engineer	

Data sources: [1] indicates "Supporting Statement for EPA Information Collection Request Number 1572.07, Hazardous Waste Specific Unit Requirements and Specialist Waste Processes and Types: November 9, 2007;" [2] indicates "Supporting Statement for EPA Information Collection Request Number 1573.12, Part B Permit Application, Permit Modifications, and Special Permits (Renewal): November 2009."

APPENDIX N

Plant-Specific and Entity-Specific Cost Estimates

Note: EPA has updated the baseline cost calculations presented in this RIA to conform with changes to the universe of plants affected by the rule and the analytic framework. See **Sections 9.2 and 9.4** in **Chapter 9** of this RIA for a description of the relevant modifications and the resultant re-estimated costs, respectively. Exhibits in this appendix have not been updated to reflect the revisions described in **Sections 9.2 and 9.4**.

Exhibit N-1: Plant Specific Cost Estimates

Exhibit N-2: Entity-Specific Cost Estimates

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Exhibit N-1 Plant-Specific Cost Estimates (annualized @ 7% discount rate) Central Estimates (Expected Values)		
Plant ID	Total Baseline Cost	CCR Final Rule Incremental Cost
3	\$8,707,477	\$4,232,525
7	\$357,553	\$453,710
8	\$18,385,015	\$4,231,689
10	\$5,270,017	\$2,661,037
26	\$7,536,774	\$5,204,505
47	\$2,064,339	\$3,986,181
50	\$53,426,935	\$23,239,855
51	\$59,498,368	\$912,573
56	\$1,624,202	\$1,415,956
59	\$42,171	\$199,149
60	\$918,028	\$1,619,131
79	\$0	\$0
87	\$808,455	\$1,181,715
108	\$1,099,491	\$228,654
113	\$6,398,793	\$5,633,166
126	\$0	\$0
127	\$3,262,188	\$1,056,816
130	\$16,624,168	\$1,161,668
136	\$12,764,145	\$375,686
160	\$8,172,798	\$2,157,550
165	\$2,894,406	\$588,800
207	\$1,566,277	\$81,367
298	\$26,163,090	\$1,652,608
384	\$947,799	\$143,040
462	\$0	\$0
465	\$2,851,330	\$1,143,771
469	\$477,141	\$1,442,395
470	\$3,991,588	\$1,222,664
477	\$723,855	\$694,568
492	\$281,301	\$1,256,489
508	\$0	\$0
525	\$2,311,025	\$1,309,746
527	\$6,519,254	\$304,089
564	\$768,247	\$150,075
568	\$0	\$0
594	\$10,631,167	\$1,338,430
602	\$308,513	\$383,693
628	\$2,714,927	\$4,582,675
641	\$2,297,640	\$1,454,200
642	\$225,820	\$822,489
643	\$3,325,579	\$1,623,709
645	\$1,880,385	\$1,484,301
663	\$2,232,463	\$467,727
667	\$289,472	\$25,778
676	\$153,118	\$111,344
703	\$6,929,573	\$1,505,701
708	\$3,123,793	\$3,272,050

Exhibit N-1 Plant-Specific Cost Estimates (annualized @ 7% discount rate) Central Estimates (Expected Values)		
Plant ID	Total Baseline Cost	CCR Final Rule Incremental Cost
709	\$6,046,759	\$5,350,637
710	\$374,681	\$1,165,543
727	\$178,672	\$796,136
728	\$6,899,534	\$4,504,681
733	\$375,644	\$775,846
753	\$200,808	\$255,705
856	\$2,853,322	\$3,081,057
861	\$6,086,864	\$292,813
867	\$0	\$0
874	\$213,833	\$747,384
876	\$2,772,676	\$2,483,748
879	\$238,525	\$1,261,235
883	\$1,201,057	\$483,152
884	\$0	\$0
886	\$0	\$0
887	\$9,447,800	\$2,956,960
889	\$9,017,535	\$2,309,273
891	\$7,070,737	\$962,093
892	\$3,494,595	\$954,758
898	\$5,680,978	\$857,907
963	\$1,885,599	\$1,092,383
976	\$6,488,467	\$5,282,496
981	\$0	\$0
983	\$9,048,474	\$5,162,341
988	\$7,007,157	\$3,270,418
990	\$7,303,288	\$5,158,226
991	\$977,359	\$1,590,741
992	\$0	\$0
994	\$14,925,102	\$8,592,882
995	\$475,273	\$1,141,267
997	\$580,453	\$1,399,610
1001	\$24,425,262	\$3,580,238
1004	\$2,580,832	\$1,115,788
1008	\$1,808,928	\$1,022,380
1010	\$4,495,317	\$1,432,080
1012	\$870,346	\$1,081,043
1024	\$0	\$0
1032	\$0	\$0
1037	\$0	\$0
1040	\$255,042	\$398,055
1043	\$1,732,750	\$2,468,582
1046	\$1,269,511	\$324,215
1047	\$849,628	\$813,774
1048	\$133,772	\$971,816
1073	\$745,294	\$1,975,995
1077	\$288,084	\$697,691
1081	\$305,342	\$721,927

Exhibit N-1 Plant-Specific Cost Estimates (annualized @ 7% discount rate) Central Estimates (Expected Values)		
Plant ID	Total Baseline Cost	CCR Final Rule Incremental Cost
1082	\$24,370,600	\$3,130,442
1091	\$2,701,279	\$1,584,210
1104	\$444,755	\$1,214,064
1122	\$845,944	\$333,670
1131	\$197,719	\$27,001
1167	\$241,498	\$25,164
1175	\$0	\$0
1217	\$262,564	\$31,384
1239	\$432,070	\$447,536
1241	\$26,179,196	\$831,675
1250	\$3,352,440	\$1,118,707
1252	\$546,708	\$510,674
1295	\$229,557	\$40,862
1353	\$9,445,723	\$3,146,980
1355	\$14,460,360	\$3,296,949
1356	\$40,217,506	\$20,578,086
1357	\$1,501,280	\$3,124,008
1361	\$798,258	\$1,392,333
1363	\$1,525,861	\$2,100,462
1364	\$23,201,505	\$8,483,962
1374	\$333,908	\$957,512
1378	\$107,772,740	\$33,797,015
1379	\$6,399,995	\$2,465,499
1381	\$4,268,817	\$3,408,973
1382	\$4,459,574	\$2,490,565
1383	\$0	\$0
1384	\$2,405,858	\$2,139,022
1385	\$702,377	\$1,293,278
1393	\$3,121,920	\$145,795
1552	\$0	\$0
1554	\$0	\$0
1570	\$1,209,349	\$781,226
1571	\$231,429	\$292,670
1572	\$113,972	\$197,442
1573	\$234,286	\$295,399
1606	\$0	\$229,905
1619	\$764,661	\$1,644,516
1626	\$0	\$0
1695	\$0	\$0
1702	\$6,740,164	\$5,826,342
1710	\$8,677,786	\$113,211
1720	\$6,467,494	\$1,693,832
1723	\$3,129,636	\$2,907,488
1731	\$380,498	\$367,627
1733	\$25,989,990	\$7,613,115
1740	\$208,183	\$332,740
1743	\$11,699,863	\$1,986,590

Exhibit N-1 Plant-Specific Cost Estimates (annualized @ 7% discount rate) Central Estimates (Expected Values)		
Plant ID	Total Baseline Cost	CCR Final Rule Incremental Cost
1745	\$8,195,880	\$2,033,711
1769	\$302,217	\$30,293
1771	\$0	\$0
1825	\$1,939,568	\$199,386
1830	\$532,000	\$349,270
1831	\$0	\$0
1832	\$337,649	\$347,417
1843	\$0	\$0
1866	\$0	\$0
1891	\$1,890,725	\$990,759
1893	\$21,328,183	\$1,061,687
1897	\$0	\$0
1904	\$267,193	\$520,612
1915	\$330,520	\$28,128
1943	\$682,800	\$84,805
1961	\$0	\$0
1979	\$0	\$0
2008	\$0	\$0
2018	\$0	\$0
2022	\$0	\$0
2049	\$2,998,208	\$1,118,494
2062	\$0	\$0
2076	\$2,863,578	\$1,615,034
2079	\$286,890	\$297,530
2080	\$2,916,409	\$841,790
2094	\$1,102,928	\$609,610
2098	\$166,168	\$326,114
2103	\$28,587,762	\$8,244,291
2104	\$1,890,693	\$1,378,189
2107	\$6,148,111	\$2,130,658
2123	\$265,321	\$410,351
2132	\$905,915	\$1,457,700
2144	\$0	\$0
2161	\$679,341	\$356,291
2167	\$7,718,118	\$1,135,292
2168	\$3,903,388	\$2,787,154
2169	\$701,609	\$414,767
2171	\$302,798	\$310,404
2187	\$623,064	\$752,605
2240	\$120,140	\$198,974
2277	\$697,949	\$205,818
2291	\$1,151,671	\$965,845
2324	\$4,194,549	\$1,220,893
2364	\$220,853	\$718,473
2367	\$0	\$0
2378	\$0	\$0
2403	\$34,494	\$737,080

Exhibit N-1 Plant-Specific Cost Estimates (annualized @ 7% discount rate) Central Estimates (Expected Values)		
Plant ID	Total Baseline Cost	CCR Final Rule Incremental Cost
2408	\$42,279	\$746,005
2434	\$0	\$0
2442	\$83,074,799	\$13,085,395
2451	\$0	\$0
2468	\$0	\$0
2527	\$2,612,369	\$1,278,566
2535	\$1,615,699	\$222,255
2549	\$2,107,589	\$778,946
2554	\$1,792,452	\$683,268
2682	\$0	\$0
2706	\$4,670,885	\$1,799,032
2708	\$914,607	\$1,426,503
2709	\$2,643,012	\$1,643,471
2712	\$10,778,113	\$1,744,921
2713	\$4,645,805	\$1,068,120
2718	\$3,008,522	\$1,316,905
2720	\$783,862	\$1,789,877
2721	\$810,568	\$2,551,746
2727	\$7,267,946	\$2,134,584
2732	\$647,361	\$713,333
2790	\$1,562,640	\$31,094
2817	\$8,848,839	\$2,122,716
2823	\$31,490,901	\$1,113,784
2824	\$2,326,961	\$950,389
2828	\$27,881,829	\$8,916,014
2830	\$5,322,526	\$5,202,451
2832	\$10,715,612	\$4,558,678
2835	\$662,249	\$492,698
2836	\$300,472	\$643,640
2837	\$202,118	\$390,485
2838	\$12,975	\$387,612
2840	\$37,223,842	\$2,215,339
2843	\$127,615	\$632,700
2848	\$185,687	\$947,825
2850	\$35,648,409	\$2,177,024
2861	\$0	\$0
2866	\$362,516	\$771,727
2872	\$3,810,796	\$2,494,262
2876	\$26,207,349	\$1,816,326
2878	\$467,558	\$400,695
2914	\$0	\$0
2917	\$0	\$0
2935	\$0	\$0
2936	\$0	\$0
2943	\$0	\$0
2952	\$731,315	\$940,226
2963	\$3,091,787	\$316,899

Exhibit N-1 Plant-Specific Cost Estimates (annualized @ 7% discount rate) Central Estimates (Expected Values)		
Plant ID	Total Baseline Cost	CCR Final Rule Incremental Cost
3098	\$751,877	\$729,566
3113	\$853,760	\$792,624
3115	\$424,918	\$65,722
3118	\$58,308,973	\$1,049,017
3122	\$4,391,010	\$2,125,623
3130	\$0	\$0
3131	\$6,103,200	\$769,522
3136	\$51,556,955	\$1,498,664
3138	\$2,480,718	\$601,207
3140	\$5,494,199	\$2,668,864
3149	\$5,246,635	\$2,492,220
3152	\$959,978	\$1,023,657
3178	\$1,064,543	\$25,495
3179	\$6,194,024	\$1,140,505
3181	\$1,282,112	\$191,907
3251	\$248,385	\$808,162
3264	\$435,887	\$770,521
3280	\$3,516,738	\$2,442,739
3287	\$116,540	\$123,464
3295	\$314,628	\$769,370
3297	\$2,662,897	\$1,411,414
3298	\$325,204	\$154,767
3319	\$1,082,241	\$1,008,189
3325	\$562,848	\$558,835
3393	\$1,791,918	\$1,229,065
3396	\$4,558,614	\$1,265,488
3399	\$20,593,685	\$2,581,499
3403	\$17,935,157	\$8,615,151
3405	\$309,010	\$648,871
3406	\$3,196,127	\$1,320,604
3407	\$2,732,450	\$1,791,817
3470	\$8,526,797	\$1,949,875
3497	\$8,715,477	\$1,086,760
3644	\$715,613	\$714,709
3775	\$2,610,693	\$1,428,553
3776	\$680,787	\$751,361
3788	\$0	\$0
3796	\$9,864,804	\$3,079,013
3797	\$14,631,883	\$13,079,378
3803	\$366,358	\$379,430
3809	\$623,941	\$146,797
3845	\$204,808	\$148,486
3935	\$54,780,935	\$3,176,882
3936	\$262,080	\$394,847
3938	\$5,859,754	\$3,438,999
3942	\$922,741	\$523,354
3943	\$3,092,936	\$171,245

Exhibit N-1 Plant-Specific Cost Estimates (annualized @ 7% discount rate) Central Estimates (Expected Values)		
Plant ID	Total Baseline Cost	CCR Final Rule Incremental Cost
3944	\$86,288,849	\$2,579,628
3945	\$332,242	\$539,461
3946	\$499,867	\$98,642
3947	\$2,507,367	\$618,423
3948	\$35,381,326	\$5,450,810
3954	\$19,239,168	\$589,424
3982	\$436,845	\$611,227
4041	\$249,716	\$93,620
4042	\$386,748	\$187,082
4050	\$2,271,700	\$1,328,078
4054	\$190,132	\$348,392
4057	\$8,987,561	\$3,161,159
4072	\$124,653	\$394,541
4078	\$1,175,878	\$1,261,012
4125	\$0	\$0
4140	\$169,013	\$93,462
4143	\$271,368	\$96,538
4150	\$0	\$0
4158	\$5,699,217	\$1,930,805
4162	\$14,250,291	\$3,796,464
4259	\$0	\$0
4271	\$169,013	\$93,462
4941	\$5,862,458	\$5,242,313
6002	\$1,670,047	\$642,406
6004	\$51,004,427	\$3,059,911
6009	\$3,905,733	\$433,458
6016	\$10,317,353	\$759,463
6017	\$14,022,637	\$11,461,322
6018	\$47,776,153	\$2,461,830
6019	\$45,219,443	\$884,188
6021	\$0	\$0
6030	\$12,208,608	\$889,205
6031	\$12,786,084	\$2,292,660
6034	\$7,557,234	\$495,366
6041	\$62,997,273	\$5,169,082
6052	\$15,687,033	\$3,422,143
6055	\$11,300,234	\$369,788
6061	\$1,341,321	\$793,155
6064	\$612,318	\$215,639
6065	\$12,174,370	\$288,101
6068	\$4,681,534	\$1,975,921
6071	\$42,192,646	\$7,156,058
6073	\$518,252	\$425,255
6076	\$71,855,217	\$11,138,684
6077	\$4,035,476	\$473,026
6082	\$15,003,726	\$477,694
6085	\$6,472,164	\$3,129,834

Exhibit N-1 Plant-Specific Cost Estimates (annualized @ 7% discount rate) Central Estimates (Expected Values)		
Plant ID	Total Baseline Cost	CCR Final Rule Incremental Cost
6089	\$3,355,038	\$907,125
6090	\$42,831,676	\$3,174,166
6094	\$63,030,235	\$55,429,049
6095	\$411,590	\$394,848
6096	\$10,273,676	\$2,267,894
6098	\$616,467	\$921,582
6101	\$2,652,092	\$535,004
6106	\$379,355	\$475,808
6113	\$41,016,491	\$5,735,441
6124	\$14,527,989	\$573,339
6136	\$1,629,211	\$1,361,723
6137	\$1,059,358	\$1,197,545
6138	\$5,541,421	\$1,364,125
6139	\$3,130,237	\$1,889,037
6146	\$1,470,405	\$1,064,354
6147	\$13,008,728	\$2,680,861
6155	\$5,026,315	\$4,255,469
6165	\$4,614,289	\$2,462,014
6166	\$24,384,684	\$4,831,232
6170	\$250,309	\$93,500
6177	\$7,843,851	\$4,279,620
6178	\$5,562,315	\$1,775,719
6179	\$5,967,898	\$450,828
6180	\$25,819,589	\$3,629,027
6181	\$344,370	\$1,693,696
6183	\$47,583,057	\$3,259,442
6190	\$1,369,040	\$255,865
6193	\$250,430	\$168,194
6194	\$147,420	\$74,089
6195	\$2,169,628	\$1,690,032
6204	\$12,207,993	\$568,833
6213	\$31,018,713	\$301,989
6225	\$0	\$0
6238	\$213,469	\$384,247
6248	\$2,633,825	\$2,561,281
6249	\$2,672,156	\$2,240,283
6250	\$2,209,452	\$1,634,541
6254	\$579,419	\$560,089
6257	\$23,784,386	\$7,929,539
6264	\$57,973,777	\$1,780,636
6288	\$1,874,213	\$1,514,147
6469	\$345,233	\$293,685
6481	\$9,909,632	\$2,257,665
6639	\$5,588,480	\$1,786,559
6641	\$5,101,142	\$539,149
6648	\$20,046,604	\$9,373,991
6664	\$3,811,824	\$369,579

Exhibit N-1 Plant-Specific Cost Estimates (annualized @ 7% discount rate) Central Estimates (Expected Values)		
Plant ID	Total Baseline Cost	CCR Final Rule Incremental Cost
6705	\$2,381,577	\$1,257,993
6761	\$1,351,730	\$594,697
6768	\$1,052,352	\$335,612
6772	\$1,827,548	\$620,055
6823	\$3,722,528	\$1,349,365
7030	\$14,484,711	\$417,927
7097	\$108,560	\$1,004,048
7210	\$1,271,983	\$150,284
7213	\$18,841,517	\$379,989
7242	\$897,881	\$30,246
7343	\$441,398	\$40,677
7504	\$0	\$0
7537	\$0	\$0
7549	\$0	\$0
7652	\$0	\$0
7790	\$2,375,801	\$1,597,287
7902	\$13,654,959	\$6,179,411
8023	\$4,553,917	\$1,229,320
8042	\$16,728,614	\$1,606,530
8066	\$11,704,962	\$6,487,766
8069	\$2,505,742	\$848,616
8102	\$62,572,101	\$6,425,535
8219	\$749,818	\$24,727
8222	\$3,191,083	\$787,879
8223	\$8,227,588	\$4,238,240
8224	\$955,311	\$204,965
8226	\$13,882,279	\$531,815
10002	\$911,899	\$405,701
10003	\$0	\$0
10030	\$300,282	\$483,431
10043	\$0	\$0
10071	\$0	\$0
10075	\$2,340,658	\$75,629
10113	\$0	\$0
10143	\$0	\$0
10148	\$0	\$0
10151	\$12,860,510	\$4,202,972
10343	\$10,300,322	\$570,766
10367	\$0	\$0
10369	\$0	\$0
10370	\$0	\$0
10371	\$0	\$0
10377	\$0	\$0
10378	\$0	\$0
10379	\$0	\$0
10380	\$0	\$0
10381	\$0	\$0

Exhibit N-1 Plant-Specific Cost Estimates (annualized @ 7% discount rate) Central Estimates (Expected Values)		
Plant ID	Total Baseline Cost	CCR Final Rule Incremental Cost
10384	\$0	\$0
10464	\$0	\$0
10495	\$0	\$0
10566	\$0	\$0
10603	\$0	\$0
10604	\$0	\$0
10640	\$0	\$0
10641	\$0	\$0
10671	\$0	\$0
10672	\$0	\$0
10673	\$0	\$0
10676	\$0	\$0
10678	\$0	\$0
10686	\$0	\$0
10743	\$0	\$0
10768	\$0	\$0
10769	\$0	\$0
10771	\$223,074	\$394,665
10774	\$0	\$0
10784	\$342,545	\$141,082
50039	\$0	\$0
50202	\$0	\$0
50407	\$0	\$0
50611	\$0	\$0
50651	\$0	\$0
50776	\$0	\$0
50835	\$0	\$0
50879	\$0	\$0
50888	\$0	\$0
50951	\$1,609,252	\$385,163
50974	\$0	\$0
50976	\$0	\$0
52007	\$0	\$0
54035	\$0	\$0
54081	\$0	\$0
54144	\$0	\$0
54304	\$0	\$0
54634	\$0	\$0
54755	\$0	\$0
55076	\$2,344,491	\$403,113
55245	\$0	\$0
55479	\$0	\$0
55749	\$0	\$0
55856	\$0	\$0
56068	\$0	\$0
56224	\$625,109	\$150,895
56319	\$0	\$0

Exhibit N-1 Plant-Specific Cost Estimates (annualized @ 7% discount rate) Central Estimates (Expected Values)		
Plant ID	Total Baseline Cost	CCR Final Rule Incremental Cost
56456	\$0	\$0
56564	\$0	\$0
56596	\$0	\$0
56609	\$0	\$0
56671	\$0	\$0
56808	\$0	\$0
56848	\$0	\$0
68029	\$0	\$0

Exhibit N-2 Entity-Specific Cost Estimates (annualized @ 7% discount rate) Central Estimates (Expected Values)		
Plant ID	Total Baseline Cost	CCR Final Rule Incremental Cost
21	\$0	\$0
25	\$2,612,369	\$1,278,566
35	\$0	\$0
52	\$911,899	\$405,701
142	\$0	\$0
177	\$0	\$0
189	\$1,624,202	\$1,415,956
195	\$41,926,884	\$17,425,871
261	\$2,381,577	\$1,257,993
353	\$0	\$0
520	\$20,109,501	\$11,754,135
554	\$845,944	\$333,670
563	\$12,860,510	\$4,202,972
733	\$122,168,027	\$10,971,278
796	\$8,172,798	\$2,157,550
803	\$89,473,591	\$18,718,561
814	\$9,006,876	\$972,607
924	\$11,621,506	\$3,922,446
986	\$0	\$0
997	\$25,819,589	\$3,629,027
998	\$0	\$0
999	\$0	\$0
1009	\$0	\$0
1307	\$21,402,065	\$2,985,235
1692	\$18,039,398	\$9,035,462
1735	\$0	\$0
1746	\$0	\$0
1951	\$0	\$0
2884	\$0	\$0
3006	\$27,881,829	\$8,916,014
3046	\$26,110,259	\$10,124,749
3203	\$197,719	\$27,001
3242	\$701,609	\$414,767
3265	\$60,867,408	\$1,168,438
3542	\$61,257,581	\$10,645,316
3593	\$2,344,491	\$403,113
3599	\$0	\$0

Exhibit N-2 Entity-Specific Cost Estimates (annualized @ 7% discount rate) Central Estimates (Expected Values)		
Plant ID	Total Baseline Cost	CCR Final Rule Incremental Cost
3989	\$1,031,119	\$1,281,216
4045	\$265,321	\$410,351
4062	\$37,351,457	\$2,848,039
4129	\$0	\$0
4161	\$308,513	\$383,693
4217	\$342,545	\$141,082
4254	\$25,015,080	\$10,540,873
4363	\$262,564	\$31,384
4508	\$0	\$0
4538	\$200,808	\$255,705
4716	\$609,394	\$283,462
4922	\$48,620,180	\$5,417,508
5109	\$54,031,648	\$12,829,149
5269	\$2,772,676	\$2,483,748
5336	\$0	\$0
5416	\$29,682,759	\$10,883,496
5517	\$25,263,846	\$5,084,031
5580	\$66,105,509	\$8,601,382
5670	\$0	\$0
5748	\$9,447,800	\$2,956,960
5860	\$3,295,648	\$2,062,570
6455	\$2,714,927	\$4,582,675
6526	\$64,737,651	\$57,872,265
6779	\$120,140	\$198,974
6909	\$2,232,463	\$467,727
7140	\$77,928,063	\$29,295,614
7199	\$0	\$0
7353	\$1,874,213	\$1,514,147
7483	\$1,939,568	\$199,386
7490	\$2,894,406	\$588,800
7570	\$14,535,569	\$1,839,594
7651	\$0	\$0
7801	\$5,849,038	\$3,900,398
7840	\$0	\$0
7860	\$300,282	\$483,431
7977	\$0	\$0
8245	\$918,028	\$1,619,131

Exhibit N-2 Entity-Specific Cost Estimates (annualized @ 7% discount rate) Central Estimates (Expected Values)		
Plant ID	Total Baseline Cost	CCR Final Rule Incremental Cost
8286	\$0	\$0
8543	\$0	\$0
8723	\$532,000	\$349,270
9231	\$1,208,714	\$1,768,104
9267	\$32,751,463	\$2,770,571
9269	\$9,048,474	\$5,162,341
9273	\$23,205,750	\$15,341,849
9324	\$31,391,841	\$8,101,650
9332	\$10,631,167	\$1,338,430
9379	\$0	\$0
9417	\$4,310,462	\$6,557,643
9617	\$1,855,749	\$107,145
9628	\$0	\$0
9645	\$0	\$0
9667	\$0	\$0
9996	\$841,876	\$256,501
10000	\$41,556,865	\$2,259,095
10171	\$56,977,404	\$28,391,376
10623	\$153,118	\$111,344
10633	\$0	\$0
11142	\$0	\$0
11208	\$9,909,632	\$2,257,665
11249	\$66,920,013	\$17,740,482
11252	\$11,300,234	\$369,788
11269	\$5,967,898	\$450,828
11571	\$0	\$0
11701	\$0	\$0
11732	\$0	\$0
12199	\$4,917,677	\$938,219
12341	\$31,630,443	\$5,846,835
12384	\$6,992,223	\$4,760,435
12588	\$0	\$0
12628	\$231,429	\$292,670
12647	\$25,559,566	\$2,128,075
12653	\$348,258	\$492,842
12658	\$31,490,901	\$1,113,784
12686	\$3,516,460	\$1,543,749

Exhibit N-2 Entity-Specific Cost Estimates (annualized @ 7% discount rate) Central Estimates (Expected Values)		
Plant ID	Total Baseline Cost	CCR Final Rule Incremental Cost
12796	\$4,847,786	\$1,332,701
12807	\$0	\$0
12949	\$0	\$0
13143	\$241,498	\$25,164
13168	\$2,107,589	\$778,946
13337	\$4,733,425	\$678,843
13407	\$4,194,549	\$1,220,893
13579	\$1,792,452	\$683,268
13695	\$0	\$0
13756	\$7,527,890	\$5,670,711
13781	\$43,866,233	\$4,334,133
13833	\$0	\$0
14006	\$104,271,590	\$14,989,030
14015	\$26,207,349	\$1,816,326
14063	\$1,142,906	\$1,335,074
14127	\$11,425,347	\$3,233,739
14165	\$17,415,346	\$2,506,227
14194	\$0	\$0
14232	\$4,490,351	\$1,794,265
14268	\$333,908	\$957,512
14354	\$42,142,206	\$16,775,377
14381	\$0	\$0
14432	\$0	\$0
14610	\$768,247	\$150,075
14645	\$0	\$0
14839	\$0	\$0
14932	\$0	\$0
15143	\$1,351,730	\$594,697
15147	\$76,773	\$1,483,085
15248	\$379,355	\$475,808
15298	\$72,478,281	\$11,891,290
15330	\$0	\$0
15452	\$0	\$0
15466	\$12,988,765	\$8,374,424
15470	\$74,326,830	\$12,885,928
15472	\$220,853	\$718,473
15473	\$0	\$0

Exhibit N-2 Entity-Specific Cost Estimates (annualized @ 7% discount rate) Central Estimates (Expected Values)		
Plant ID	Total Baseline Cost	CCR Final Rule Incremental Cost
15474	\$6,353,975	\$1,373,715
15534	\$5,246,635	\$2,492,220
15537	\$5,494,199	\$2,668,864
15698	\$0	\$0
15873	\$109,865,929	\$2,547,681
15989	\$255,042	\$398,055
16002	\$0	\$0
16061	\$0	\$0
16181	\$0	\$0
16233	\$0	\$0
16572	\$13,706,308	\$9,521,933
16604	\$452,930	\$2,697,743
16624	\$47,583,057	\$3,259,442
16793	\$0	\$0
17043	\$0	\$0
17166	\$955,311	\$204,965
17177	\$1,052,352	\$335,612
17235	\$7,381,878	\$1,627,869
17539	\$7,882,785	\$4,897,270
17543	\$20,378,565	\$4,410,140
17554	\$325,204	\$154,767
17568	\$1,341,321	\$793,155
17632	\$6,488,467	\$5,282,496
17633	\$1,929,703	\$2,278,589
17698	\$22,326,617	\$9,432,573
17718	\$397,850	\$242,283
17828	\$1,885,599	\$1,092,383
17833	\$2,848,970	\$2,046,323
18041	\$0	\$0
18315	\$1,099,491	\$228,654
18414	\$0	\$0
18454	\$2,778,266	\$1,514,547
18642	\$220,780,969	\$80,941,045
18715	\$1,629,211	\$1,361,723
19099	\$204,808	\$148,486
19145	\$0	\$0
19173	\$0	\$0

Exhibit N-2 Entity-Specific Cost Estimates (annualized @ 7% discount rate) Central Estimates (Expected Values)		
Plant ID	Total Baseline Cost	CCR Final Rule Incremental Cost
19194	\$0	\$0
19323	\$43,241,216	\$14,205,967
19436	\$41,652,881	\$16,008,607
19545	\$562,848	\$558,835
19578	\$0	\$0
19856	\$0	\$0
19876	\$63,790,745	\$18,048,697
19883	\$0	\$0
20447	\$1,827,548	\$620,055
20541	\$0	\$0
20737	\$0	\$0
20847	\$1,188,991	\$404,494
20856	\$16,003,310	\$6,066,949
20860	\$1,300,530	\$1,655,552
21025	\$0	\$0
21048	\$0	\$0
21554	\$12,764,145	\$375,686
21734	\$1,609,252	\$385,163
22001	\$959,978	\$1,023,657
22053	\$9,445,723	\$3,146,980
22125	\$1,615,699	\$222,255
22129	\$15,003,726	\$477,694
22500	\$8,580,681	\$3,605,302
23279	\$147,043,305	\$7,778,673
24211	\$8,227,588	\$4,238,240
30151	\$7,327,710	\$1,485,804
34672	\$0	\$0
40230	\$2,375,801	\$1,597,287
40307	\$213,469	\$384,247
40606	\$42,171	\$199,149
49756	\$13,170,675	\$3,840,520
49889	\$10,300,322	\$570,766
49896	\$625,109	\$150,895
50018	\$764,661	\$1,644,516
54784	\$0	\$0
54885	\$0	\$0
54888	\$34,689,888	\$3,602,483

Exhibit N-2 Entity-Specific Cost Estimates (annualized @ 7% discount rate) Central Estimates (Expected Values)		
Plant ID	Total Baseline Cost	CCR Final Rule Incremental Cost
54889	\$0	\$0
54895	\$0	\$229,905
55729	\$47,776,153	\$2,461,830
55739	\$0	\$0
55740	\$0	\$0
55768	\$0	\$0
55807	\$0	\$0
55808	\$0	\$0
55924	\$0	\$0
55936	\$3,121,920	\$145,795
55995	\$0	\$0
56069	\$0	\$0
56146	\$0	\$0
56155	\$337,649	\$347,417
56190	\$0	\$0
56211	\$1,269,096	\$935,725
56217	\$0	\$0
56570	\$5,562,315	\$1,775,719
56598	\$14,484,711	\$417,927
56614	\$0	\$0

APPENDIX O

Detailed Information Used to Estimate Benefits for Each LF and SI

Note: EPA has updated the universe to reflect 61 actual and projected plant retirements occurring after 2012 according to the National Electric Energy Data System (NEEDS) v.5.13 dataset; see **Section 9.2.1** in **Chapter 9** for a description of the relevant updates. Exhibits in this appendix have not been updated to reflect the revisions described in **Section 9.2.1**.

Exhibit O-1: Detailed Information Used to Estimate Benefits for Universe of CCR Landfills

Exhibit O-2: Detailed Information Used to Estimate Benefits for Universe of CCR Surface Impoundments

Note that these exhibits present inputs to the benefits analysis, and therefore incorporate assumptions to correct for incomplete or missing data. For this reason, these exhibits should not be used to summarize characteristics of the universe of regulated facilities.

Exhibit O-1					
Detailed Information Used to Estimate Benefits for Universe of Landfills					
Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring
1	8LANDFILL	LF	Unknown	AL	early
2	47LANDFILL-1	LF	NA	AL	early
3	56LANDFILL	LF	Unknown	AL	early
4	6009LANDFILL-1	LF	Yes	AR	never
5	6138LANDFILL-1	LF	Yes	AR	never
6	6641LANDFILL-1	LF	Clay	AR	never
7	113LANDFILL-1	LF	NA	AZ	never
8	4941LANDFILL-1	LF	NA	AZ	never
9	6177LANDFILL-1	LF	NA	AZ	never
10	8223LANDFILL-1	LF	NA	AZ	never
11	10002LANDFILL	LF	Unknown	CA	never
12	470LANDFILL-1	LF	NA	CO	early
13	477LANDFILL-1	LF	NA	CO	early
14	492LANDFILL-1	LF	NA	CO	early
15	525LANDFILL-1	LF	NA	CO	early
16	527LANDFILL	LF	Unknown	CO	early
17	6248LANDFILL-1	LF	NA	CO	early
18	6761LANDFILL-1	LF	NA	CO	early
19	6761No Answer	LF	Unknown	CO	early
20	8219LANDFILL-1	LF	NA	CO	early
21	594LANDFILL-1	LF	Yes	DE	never
22	136LANDFILL-1	LF	Yes	FL	late
23	207LANDFILL-2	LF	NA	FL	late
24	207LANDFILL-3	LF	NA	FL	late
25	564LANDFILL-1	LF	NA	FL	late
26	628LANDFILL-1	LF	NA	FL	late
27	641LANDFILL-1	LF	Yes	FL	late
28	643LANDFILL-1	LF	Yes	FL	late
29	645LANDFILL-1	LF	NA	FL	late
30	663LANDFILL-1	LF	Yes	FL	late
31	667LANDFILL-1	LF	Yes	FL	late
32	676LANDFILL-1	LF	NA	FL	late

Exhibit O-1					
Detailed Information Used to Estimate Benefits for Universe of Landfills					
Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring
33	7242LANDFILL-1	LF	Yes	FL	late
34	703LANDFILL-1	LF	Yes	GA	early
35	708LANDFILL-1	LF	Yes	GA	early
36	710LANDFILL	LF	Unknown	GA	early
37	728LANDFILL-1	LF	NA	GA	early
38	728LANDFILL-2	LF	Yes	GA	early
39	733LANDFILL-1	LF	NA	GA	early
40	1047LANDFILL-1	LF	NA	IA	early
41	1082LANDFILL-1	LF	Synthetic	IA	early
42	1091LANDFILL-1	LF	Yes	IA	early
43	1091LANDFILL-2	LF	Unknown	IA	early
44	1091LANDFILL-3	LF	Unknown	IA	early
45	1131LANDFILL-1	LF	NA	IA	early
46	1167LANDFILL-1	LF	Yes	IA	early
47	1217LANDFILL-1	LF	NA	IA	early
48	6254LANDFILL-1	LF	Yes	IA	early
49	6664LANDFILL-1	LF	NA	IA	early
50	7343LANDFILL-1	LF	NA	IA	early
51	384LANDFILL	LF	Unknown	IL	late
52	861LANDFILL-1	LF	Yes	IL	late
53	876LANDFILL	LF	Unknown	IL	late
54	887LANDFILL-1	LF	Yes	IL	late
55	892LANDFILL-1	LF	Yes	IL	late
56	963LANDFILL-1	LF	Yes	IL	late
57	976LANDFILL-1	LF	NA	IL	late
58	6016LANDFILL-1	LF	Synthetic	IL	late
59	6017LANDFILL-1	LF	Yes	IL	late
60	983LANDFILL-1	LF	NA	IN	early
61	983LANDFILL-2	LF	Yes	IN	early
62	988LANDFILL-1	LF	Yes	IN	early
63	994LANDFILL-1	LF	Yes	IN	early
64	1001LANDFILL-1	LF	Synthetic	IN	early

Exhibit O-1					
Detailed Information Used to Estimate Benefits for Universe of Landfills					
Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring
65	1004LANDFILL	LF	Unknown	IN	early
66	1008LANDFILL-1	LF	Unknown	IN	early
67	1008LANDFILL-2	LF	Unknown	IN	early
68	1008LANDFILL-3	LF	Unknown	IN	early
69	1008LANDFILL-4	LF	Unknown	IN	early
70	1008No Answer	LF	Unknown	IN	early
71	6085LANDFILL-1	LF	Yes	IN	early
72	6113LANDFILL-1	LF	Synthetic	IN	early
73	6113LANDFILL-2	LF	Synthetic	IN	early
74	6137LANDFILL-1	LF	Yes	IN	early
75	6166LANDFILL-1	LF	Yes	IN	early
76	6213LANDFILL-1	LF	Yes	IN	early
77	108LANDFILL-1	LF	NA	KS	early
78	1241LANDFILL-1	LF	Yes	KS	early
79	1250LANDFILL-1	LF	NA	KS	early
80	1250LANDFILL-2	LF	Yes	KS	early
81	1252-999	LF	Unknown	KS	early
82	1252LANDFILL-1	LF	NA	KS	early
83	1295LANDFILL-1	LF	Yes	KS	early
84	6064LANDFILL-1	LF	Yes	KS	early
85	6064LANDFILL-2	LF	NA	KS	early
86	6068LANDFILL-1	LF	NA	KS	early
87	6068LANDFILL-2	LF	NA	KS	early
88	1363LANDFILL-1	LF	NA	KY	early
89	1364LANDFILL-1	LF	NA	KY	early
90	1364LANDFILL-2	LF	Yes	KY	early
91	1364LANDFILL-3	LF	NA	KY	early
92	1379LANDFILL-1	LF	NA	KY	early
93	1379LANDFILL-2	LF	Unknown	KY	early
94	1382LANDFILL	LF	Unknown	KY	early
95	1384LANDFILL	LF	Unknown	KY	early
96	6018LANDFILL-1	LF	Yes	KY	early

Exhibit O-1					
Detailed Information Used to Estimate Benefits for Universe of Landfills					
Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring
97	6041LANDFILL-1	LF	Clay	KY	early
98	6639LANDFILL-1	LF	NA	KY	early
99	6823LANDFILL-1	LF	NA	KY	early
100	6823LANDFILL-2	LF	NA	KY	early
101	51LANDFILL-1	LF	Yes	LA	late
102	1393LANDFILL-1	LF	Yes	LA	late
103	1393LANDFILL-2	LF	Yes	LA	late
104	6055LANDFILL-1	LF	Clay	LA	late
105	1619LANDFILL-1	LF	Yes	MA	never
106	1570LANDFILL-1	LF	Yes	MD	early
107	1571LANDFILL-1	LF	Yes	MD	early
108	1571LANDFILL-2	LF	Yes	MD	early
109	1572LANDFILL-2	LF	Yes	MD	early
110	1573LANDFILL-1	LF	Yes	MD	early
111	1573LANDFILL-2	LF	Yes	MD	early
112	1702LANDFILL-1	LF	Unknown	MI	never
113	1710LANDFILL-1	LF	Synthetic	MI	never
114	1710LANDFILL-2	LF	Synthetic	MI	never
115	1710LANDFILL-3	LF	Synthetic	MI	never
116	1710LANDFILL-4	LF	Synthetic	MI	never
117	1720LANDFILL-1	LF	Unknown	MI	never
118	1745LANDFILL-1	LF	NA	MI	never
119	1769LANDFILL-1	LF	Yes	MI	never
120	1830LANDFILL-1	LF	NA	MI	never
121	6034LANDFILL-1	LF	Yes	MI	never
122	1893LANDFILL-1	LF	NA	MN	early
123	1893LANDFILL-2	LF	NA	MN	early
124	1915LANDFILL-1	LF	Yes	MN	early
125	1943LANDFILL-1	LF	NA	MN	early
126	1943LANDFILL-2	LF	NA	MN	early
127	1943LANDFILL-3	LF	Yes	MN	early
128	6090LANDFILL-1	LF	Yes	MN	early

Exhibit O-1					
Detailed Information Used to Estimate Benefits for Universe of Landfills					
Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring
129	10075LANDFILL-1	LF	Yes	MN	early
130	10075LANDFILL-2	LF	Yes	MN	early
131	10075LANDFILL-3	LF	Yes	MN	early
132	2079LANDFILL	LF	Unknown	MO	late
133	2080LANDFILL-1	LF	Yes	MO	late
134	2094LANDFILL-1	LF	Yes	MO	late
135	2161LANDFILL-1	LF	Synthetic	MO	late
136	2167LANDFILL-1	LF	Yes	MO	late
137	2168LANDFILL-1	LF	NA	MO	late
138	6065LANDFILL-1	LF	Yes	MO	late
139	6195LANDFILL-1	LF	NA	MO	late
140	2049LANDFILL-1	LF	Yes	MS	late
141	6061LANDFILL-1	LF	Unknown	MS	late
142	6061LANDFILL-2	LF	Unknown	MS	late
143	6061LANDFILL-3	LF	Yes	MS	late
144	6073LANDFILL-1	LF	Yes	MS	late
145	6073LANDFILL-2	LF	Yes	MS	late
146	55076LANDFILL-1	LF	Yes	MS	late
147	6089LANDFILL-1	LF	NA	MT	early
148	10784LANDFILL-1	LF	NA	MT	early
149	2712LANDFILL-1	LF	NA	NC	early
150	2718LANDFILL-1	LF	Yes	NC	early
151	2727LANDFILL-1	LF	Synthetic	NC	early
152	8042LANDFILL-1	LF	Synthetic	NC	early
153	8042LANDFILL-2	LF	Synthetic	NC	early
154	2790LANDFILL-1	LF	Yes	ND	early
155	2817LANDFILL-1	LF	NA	ND	early
156	2817LANDFILL-2	LF	Yes	ND	early
157	2823LANDFILL-1	LF	Yes	ND	early
158	2823LANDFILL-2	LF	NA	ND	early

Exhibit O-1					
Detailed Information Used to Estimate Benefits for Universe of Landfills					
Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring
159	2824LANDFILL-1	LF	Clay	ND	early
160	2824LANDFILL-2	LF	Clay	ND	early
161	6030LANDFILL-1	LF	Yes	ND	early
162	6030LANDFILL-2	LF	Yes	ND	early
163	6030LANDFILL-3	LF	Yes	ND	early
164	6469LANDFILL-1	LF	Clay	ND	early
165	6469LANDFILL-2	LF	Clay	ND	early
166	8222LANDFILL-1	LF	Clay	ND	early
167	8222LANDFILL-2	LF	NA	ND	early
168	59LANDFILL-1	LF	NA	NE	never
169	2240LANDFILL-1	LF	Yes	NE	never
170	2277LANDFILL-1	LF	Yes	NE	never
171	2291LANDFILL-1	LF	NA	NE	never
172	6077LANDFILL-1	LF	Yes	NE	never
173	6096LANDFILL-1	LF	NA	NE	never
174	6096LANDFILL-2	LF	Yes	NE	never
175	2364LANDFILL-1	LF	Yes	NH	never
176	2403LANDFILL-1	LF	NA	NJ	never
177	2408LANDFILL-1	LF	NA	NJ	never
178	87LANDFILL-1	LF	Clay	NM	never
179	2442LANDFILL-1	LF	Yes	NM	never
180	2442LANDFILL-2	LF	NA	NM	never
181	2324LANDFILL-1	LF	NA	NV	late
182	8224LANDFILL-1	LF	NA	NV	late
183	56224LANDFILL	LF	Unknown	NV	late
184	2527LANDFILL-1	LF	Yes	NY	early
185	2535LANDFILL-1	LF	Yes	NY	early
186	2549LANDFILL-1	LF	Yes	NY	early
187	2554LANDFILL-1	LF	Synthetic	NY	early
188	6082LANDFILL-1	LF	Synthetic	NY	early
189	2828LANDFILL-1	LF	Yes	OH	early
190	2830LANDFILL-1	LF	Clay	OH	early

Exhibit O-1					
Detailed Information Used to Estimate Benefits for Universe of Landfills					
Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring
191	2832LANDFILL-1	LF	Yes	OH	early
192	2836LANDFILL	LF	Unknown	OH	early
193	2837LANDFILL-1	LF	Yes	OH	early
194	2840LANDFILL-1	LF	Synthetic	OH	early
195	2850LANDFILL-1	LF	Yes	OH	early
196	2850LANDFILL-2	LF	Yes	OH	early
197	2866LANDFILL-1	LF	Synthetic	OH	early
198	2876LANDFILL-1	LF	Yes	OH	early
199	2878LANDFILL	LF	Unknown	OH	early
200	6019LANDFILL-1	LF	Yes	OH	early
201	8102LANDFILL-1	LF	Synthetic	OH	early
202	165LANDFILL-1	LF	Yes	OK	late
203	2963LANDFILL-1	LF	Yes	OK	late
204	6772LANDFILL-1	LF	Clay	OK	late
205	6106LANDFILL-1	LF	NA	OR	never
206	3113LANDFILL-1	LF	Synthetic	PA	early
207	3115LANDFILL-1	LF	NA	PA	early
208	3118LANDFILL-1	LF	Yes	PA	early
209	3122LANDFILL-1	LF	NA	PA	early
210	3122LANDFILL-2	LF	Synthetic	PA	early
211	3131LANDFILL-1	LF	Yes	PA	early
212	3136LANDFILL-1	LF	Yes	PA	early
213	3136LANDFILL-2	LF	Yes	PA	early
214	3138LANDFILL-1	LF	Synthetic	PA	early
215	3140LANDFILL-1	LF	Yes	PA	early
216	3149LANDFILL-1	LF	Yes	PA	early
217	3178LANDFILL-1	LF	Yes	PA	early
218	3179LANDFILL-1	LF	NA	PA	early
219	3181LANDFILL-1	LF	NA	PA	early
220	8226LANDFILL-1	LF	Yes	PA	early
221	10343LANDFILL-1	LF	Unknown	PA	early
222	130LANDFILL-1	LF	NA	SC	early

Exhibit O-1					
Detailed Information Used to Estimate Benefits for Universe of Landfills					
Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring
223	130LANDFILL-2	LF	Unknown	SC	early
224	130LANDFILL-3	LF	Unknown	SC	early
225	130LANDFILL-4	LF	Unknown	SC	early
226	3287LANDFILL-1	LF	NA	SC	early
227	3295LANDFILL-1	LF	NA	SC	early
228	3297LANDFILL-1	LF	Yes	SC	early
229	3298LANDFILL-1	LF	Yes	SC	early
230	3298LANDFILL-2	LF	Yes	SC	early
231	6249LANDFILL	LF	Unknown	SC	early
232	7210LANDFILL-1	LF	NA	SC	early
233	6098LANDFILL-1	LF	NA	SD	never
234	3396LANDFILL-1	LF	NA	TN	early
235	3399LANDFILL	LF	Unknown	TN	early
236	3405LANDFILL-1	LF	Synthetic	TN	early
237	3406LANDFILL-1	LF	NA	TN	early
238	127LANDFILL	LF	Unknown	TX	late
239	298LANDFILL-1	LF	Yes	TX	late
240	3470LANDFILL-1	LF	Yes	TX	late
241	3497LANDFILL-1	LF	Clay	TX	late
242	6136LANDFILL-1	LF	Yes	TX	late
243	6136LANDFILL-2	LF	Yes	TX	late
244	6139LANDFILL-1	LF	NA	TX	late
245	6146LANDFILL-1	LF	Yes	TX	late
246	6147LANDFILL-1	LF	NA	TX	late
247	6147LANDFILL-2	LF	Yes	TX	late
248	6179LANDFILL-2	LF	Yes	TX	late
249	6180LANDFILL-1	LF	Yes	TX	late
250	6180LANDFILL-2	LF	NA	TX	late
251	6180LANDFILL-3	LF	NA	TX	late
252	6181LANDFILL-1	LF	Yes	TX	late
253	6181LANDFILL-2	LF	Unknown	TX	late
254	6183LANDFILL-1	LF	Yes	TX	late

Exhibit O-1					
Detailed Information Used to Estimate Benefits for Universe of Landfills					
Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring
255	6193LANDFILL-1	LF	Yes	TX	late
256	6193LANDFILL-2	LF	Yes	TX	late
257	6194LANDFILL-4	LF	NA	TX	late
258	6648LANDFILL-1	LF	Clay	TX	late
259	6648LANDFILL-2	LF	NA	TX	late
260	6648LANDFILL-3	LF	NA	TX	late
261	6648LANDFILL-4	LF	NA	TX	late
262	7030LANDFILL-1	LF	Yes	TX	late
263	7097LANDFILL-1	LF	Yes	TX	late
264	7902LANDFILL-1	LF	Synthetic	TX	late
265	3644LANDFILL-1	LF	NA	UT	early
266	6165LANDFILL-1	LF	NA	UT	early
267	7790LANDFILL-1	LF	NA	UT	early
268	7790LANDFILL-2	LF	NA	UT	early
269	8069LANDFILL-1	LF	NA	UT	early
270	8069LANDFILL-2	LF	NA	UT	early
271	50951LANDFILL-1	LF	NA	UT	early
272	3775LANDFILL-1	LF	Yes	VA	early
273	3776LANDFILL-1	LF	Yes	VA	early
274	3803LANDFILL-1	LF	Yes	VA	early
275	3809LANDFILL-1	LF	Clay	VA	early
276	7213LANDFILL-1	LF	Synthetic	VA	early
277	3845LANDFILL-1	LF	Yes	WA	early
278	3982LANDFILL-1	LF	Yes	WI	late
279	4041LANDFILL-1	LF	Yes	WI	late
280	4042LANDFILL-1	LF	Yes	WI	late
281	4042LANDFILL-2	LF	Yes	WI	late
282	4050LANDFILL-1	LF	Yes	WI	late
283	4078LANDFILL-1	LF	Yes	WI	late
284	4140LANDFILL-1	LF	Unknown	WI	late
285	4143LANDFILL-1	LF	Unknown	WI	late
286	4271LANDFILL-1	LF	Unknown	WI	late

Exhibit O-1					
Detailed Information Used to Estimate Benefits for Universe of Landfills					
Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring
287	6170LANDFILL-1	LF	Yes	WI	late
288	8023LANDFILL-1	LF	Yes	WI	late
289	3935LANDFILL-1	LF	Yes	WV	late
290	3935LANDFILL-2	LF	Yes	WV	late
291	3938LANDFILL	LF	Unknown	WV	late
292	3942LANDFILL-1	LF	NA	WV	late
293	3943LANDFILL-1	LF	NA	WV	late
294	3943LANDFILL-2	LF	Yes	WV	late
295	3944LANDFILL-1	LF	Clay	WV	late
296	3945LANDFILL-1	LF	NA	WV	late
297	3946LANDFILL-1	LF	Yes	WV	late
298	3954LANDFILL-1	LF	NA	WV	late
299	3954LANDFILL-2	LF	Synthetic	WV	late
300	3954LANDFILL-3	LF	Clay	WV	late
301	6004LANDFILL-1	LF	Yes	WV	late
302	6264LANDFILL-1	LF	Synthetic	WV	late
303	10151LANDFILL-1	LF	NA	WV	late
304	10151LANDFILL-2	LF	NA	WV	late
305	10151LANDFILL-3	LF	NA	WV	late
306	4158LANDFILL-1	LF	NA	WY	early
307	4162LANDFILL	LF	Unknown	WY	early
308	6101LANDFILL	LF	Unknown	WY	early
309	6204LANDFILL-1	LF	NA	WY	early
310	8066LANDFILL-1	LF	NA	WY	early

Exhibit O-2

Detailed Information Used to Estimate Benefits for Universe of Surface Impoundments

Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring	Capacity (Acre Feet)	Size Class
1	6288SPD-1	SI	NA	AK	never	9	Small
2	3Barry Ash Pond	SI	NA	AL	early	5,965	Large
3	7Ash Pond (NID #1428)	SI	Unknown	AL	early	753	Large
4	8Ash Pond (NID #1198) Rattlesnake Dam	SI	NA	AL	early	10,750	Large
5	8Gypsum Storage Facility	SI	Yes	AL	early	983	Large
6	10Ash Pond	SI	NA	AL	early	5,331	Large
7	26Ash Pond Dam	SI	NA	AL	early	18,888	Large
8	47Ash Pond 4	SI	Unknown	AL	early	1,364	Large
9	47Disposal Area 5	SI	Unknown	AL	early	5,455	Large
10	47Disposal Area 5 Basin	SI	Unknown	AL	early	372	Large
11	50Ash Pond	SI	Unknown	AL	early	11,709	Large
12	50Bottom Ash Stack	SI	NA	AL	early	448	Large
13	50Dredge Cell	SI	NA	AL	early	1,624	Large
14	50Gypsum Stack (Wet Stacking Area)	SI	Unknown	AL	early	10,961	Large
15	50Gypsum Stack Pond 1	SI	NA	AL	early	140	Large
16	50Gypsum Stack Pond 2A	SI	NA	AL	early	168	Large
17	50Gypsum Stack Pond 2B	SI	NA	AL	early	196	Large
18	50Gypsum Stack Pond 3	SI	NA	AL	early	826	Large
19	50Gypsum Stack Stilling Pond	SI	NA	AL	early	126	Large
20	50Pump Pond	SI	NA	AL	early	4	Small
21	50Red Water Pond	SI	NA	AL	early	448	Large
22	50Upper/Lower Stilling Pond	SI	NA	AL	early	112	Large
23	56#1 Bottom Ash Pond	SI	NA	AL	early	330	Large
24	56Process Waste Pond	SI	NA	AL	early	84	Large
25	56Scrubber Waste Pond	SI	NA	AL	early	760	Large
26	56Units 2-3 Pond	SI	NA	AL	early	629	Large
27	6002Ash Pond (NID #1101)	SI	Unknown	AL	early	13,606	Large
28	6138Primary Bottom Ash Pond	SI	Unknown	AR	never	484	Large
29	6138Secondary Bottom Ash Pond	SI	Unknown	AR	never	24	Large
30	113Bottom Ash Pond	SI	NA	AZ	never	2,300	Large
31	113Fly Ash Pond	SI	NA	AZ	never	18,000	Large
32	160Ash Pond 1	SI	Yes	AZ	never	717	Large

Exhibit O-2

Detailed Information Used to Estimate Benefits for Universe of Surface Impoundments

Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring	Capacity (Acre Feet)	Size Class
33	160Ash Pond 2	SI	Yes	AZ	never	720	Large
34	160Ash Pond 3	SI	Yes	AZ	never	720	Large
35	160Ash Pond 4	SI	Yes	AZ	never	693	Large
36	160Cooling Tower Blowdown Pond	SI	Unknown	AZ	never	7	Small
37	160Evaporation 1	SI	Yes	AZ	never	823	Large
38	160Evaporation Pond	SI	Yes	AZ	never	1,120	Large
39	160Low Volume Wastewater Pond	SI	Unknown	AZ	never	618	Large
40	160Scrubber Sludge Pond 1	SI	Yes	AZ	never	314	Large
41	160Scrubber Sludge Pond 2	SI	Yes	AZ	never	446	Large
42	6177Evaporation Pond/Dam	SI	NA	AZ	never	5,900	Large
43	465Ash Pump Pond	SI	Unknown	CO	early	4	Small
44	465South Ash Pond	SI	Unknown	CO	early	14	Small
45	469Center Ash Pond	SI	Unknown	CO	early	10	Small
46	469East Ash Pond	SI	Unknown	CO	early	8	Small
47	469East Polishing Pond	SI	Unknown	CO	early	16	Small
48	469Emergency Spill Pond	SI	Unknown	CO	early	5	Small
49	469West Ash Pond	SI	Unknown	CO	early	8	Small
50	469West Polishing Pond	SI	Unknown	CO	early	16	Small
51	470Ash Disposal Facility (ADF) Stormwater Retention Pond	SI	Unknown	CO	early	8	Small
52	470Ash Pond #1	SI	Unknown	CO	early	12	Small
53	470Ash Pond #2	SI	Unknown	CO	early	12	Small
54	470Ash Pond #3	SI	Unknown	CO	early	12	Small
55	470Polishing Pond (#4)	SI	Unknown	CO	early	12	Small
56	477East Ash Settling Pond	SI	Unknown	CO	early	16	Small
57	477West Ash Settling Pond	SI	Unknown	CO	early	16	Small
58	492SPD-1	SI	NA	CO	early	0	Small
59	492SPD-5	SI	NA	CO	early	0	Small
60	492SPD-6	SI	NA	CO	early	0	Small
61	492SPD-7	SI	NA	CO	early	0	Small
62	525Ash Disposal Facility (ADF) Contact Storm Water Pond	SI	Unknown	CO	early	4	Small
63	525Common Wet Ash Settling Basin	SI	Unknown	CO	early	182	Large
64	525Fly Ash Decant Basin	SI	Unknown	CO	early	182	Large

Exhibit O-2

Detailed Information Used to Estimate Benefits for Universe of Surface Impoundments

Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring	Capacity (Acre Feet)	Size Class
65	525Intermediate Quality Pond	SI	Unknown	CO	early	274	Large
66	527Coal/Ash Settling Basin	SI	Unknown	CO	early	182	Large
67	6248Ash Disposal Facility (ADF)	SI	Unknown	CO	early	1,349	Large
68	6248Evaporative Pond B	SI	Unknown	CO	early	138	Large
69	6248Evaporative Pond C	SI	Unknown	CO	early	96	Large
70	6248Intermediate Quality (IQ) Water Pond	SI	Unknown	CO	early	48	Large
71	6248New Bottom Ash Water Recovery Pond	SI	Unknown	CO	early	52	Large
72	6761North Bottom Ash Transfer Pond	SI	Unknown	CO	early	37	Large
73	6761South Bottom Ash Transfer Pond	SI	Unknown	CO	early	37	Large
74	594Sedimentation Pond	SI	Unknown	DE	never	182	Large
75	10030Waste Water Pond	SI	Unknown	DE	never	0	Small
76	641SPD-1	SI	NA	FL	late	241	Large
77	641SPD-5	SI	NA	FL	late	9	Small
78	641SPD-6	SI	Yes	FL	late	403	Large
79	642SPD-1	SI	NA	FL	late	376	Large
80	642SPD-2	SI	NA	FL	late	146	Small
81	642SPD-3	SI	NA	FL	late	168	Large
82	643Ash Pond	SI	NA	FL	late	2,611	Large
83	645Longterm Flyash Pond	SI	Unknown	FL	late	168	Large
84	645North Bottom Ash	SI	Yes	FL	late	80	Large
85	645North Economizer Ash Pond	SI	Yes	FL	late	77	Large
86	645North Recycle Pond	SI	Unknown	FL	late	42	Large
87	645Settling Pond	SI	Unknown	FL	late	14	Small
88	645South Bottom Ash Pond	SI	Yes	FL	late	84	Large
89	645South Economizer Ash Pond	SI	Yes	FL	late	84	Large
90	645South Recycle Pond	SI	Unknown	FL	late	126	Large
91	663SPD-1	SI	NA	FL	late	53	Large
92	703Ash Pond	SI	Clay	GA	early	3,676	Large
93	708Ash Pond 1	SI	NA	GA	early	800	Large
94	708Ash Pond 2	SI	NA	GA	early	509	Large
95	708Ash Pond 4	SI	NA	GA	early	1,242	Large
96	709Ash Pond B	SI	NA	GA	early	750	Large

Exhibit O-2

Detailed Information Used to Estimate Benefits for Universe of Surface Impoundments

Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring	Capacity (Acre Feet)	Size Class
97	709Ash Pond C	SI	NA	GA	early	1,050	Large
98	709Ash Pond D	SI	NA	GA	early	675	Large
99	709Ash Pond E	SI	NA	GA	early	4,665	Large
100	710Ash Pond 2	SI	NA	GA	early	118	Large
101	710Ash Pond 3	SI	NA	GA	early	642	Large
102	710Ash Pond 4	SI	NA	GA	early	1,996	Large
103	727Ash Pond 1	SI	NA	GA	early	659	Large
104	727Ash Pond 2	SI	NA	GA	early	644	Large
105	727Ash Pond A	SI	NA	GA	early	61	Large
106	728Ash Pond 1	SI	NA	GA	early	184	Large
107	728Ash Pond 2	SI	NA	GA	early	1,103	Large
108	728Ash Pond 3	SI	NA	GA	early	434	Large
109	728B' Pond	SI	NA	GA	early	298	Large
110	728Gypsum Solid Waste Facility	SI	Yes	GA	early	135	Large
111	733Ash Pond	SI	Unknown	GA	early	41	Large
112	753SPD-1	SI	Unknown	GA	early	0	Small
113	6052Ash Pond	SI	NA	GA	early	16,920	Large
114	6124Ash Pond	SI	Unknown	GA	early	342	Large
115	6257Ash Pond	SI	NA	GA	early	15,955	Large
116	6257Settlement-Recycle Pond	SI	NA	GA	early	0	Small
117	1046Ash Channel	SI	Unknown	IA	early	10	Small
118	1047Lower Ash Pond	SI	NA	IA	early	2	Small
119	1047Main Ash Pond	SI	NA	IA	early	294	Large
120	1048Emergency Ash Primary Settling Pond	SI	NA	IA	early	3	Small
121	1048Emergency Ash Secondary Settling Pond	SI	NA	IA	early	2	Small
122	1048Main Ash Primary Settling Pond	SI	NA	IA	early	4	Small
123	1048Main Ash Secondary Settling Pond	SI	NA	IA	early	1	Small
124	1073Ash Pond #1	SI	Unknown	IA	early	4	Small
125	1073Ash Pond #10	SI	Unknown	IA	early	1	Small
126	1073Ash Pond #2	SI	Unknown	IA	early	8	Small
127	1073Ash Pond #3	SI	Unknown	IA	early	7	Small
128	1073Ash Pond #4	SI	Unknown	IA	early	8	Small

Exhibit O-2

Detailed Information Used to Estimate Benefits for Universe of Surface Impoundments

Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring	Capacity (Acre Feet)	Size Class
129	1073Ash Pond #5	SI	Unknown	IA	early	12	Small
130	1073Ash Pond #6	SI	Unknown	IA	early	14	Small
131	1073Ash Pond #7	SI	Unknown	IA	early	1	Small
132	1073Ash Pond #8 - Plant Drains	SI	Unknown	IA	early	182	Large
133	1073Ash Pond #9 - Dumper Building	SI	Unknown	IA	early	1	Small
134	1077Main Ash Settling Pond	SI	Unknown	IA	early	52	Large
135	1077Unit 1 & 2 Initial Settling Pond	SI	Unknown	IA	early	2	Small
136	1077Unit 3 Initial Settling Pond	SI	Unknown	IA	early	1	Small
137	1081North Ash Pond	SI	NA	IA	early	84	Large
138	1081South Ash Pond	SI	NA	IA	early	140	Large
139	1082North Surface Impoundment	SI	NA	IA	early	2,046	Large
140	1082South Surface Impoundment	SI	NA	IA	early	1,326	Large
141	1091Surface Impoundment 1	SI	NA	IA	early	137	Large
142	1091Surface Impoundment 2	SI	NA	IA	early	296	Large
143	1091Surface Impoundment 3	SI	NA	IA	early	837	Large
144	1104Economizer Ash Pond	SI	NA	IA	early	166	Large
145	1104Lower Ash Pond	SI	NA	IA	early	114	Small
146	1104Main Ash Pond	SI	NA	IA	early	85	Small
147	1104Upper Ash Pond	SI	NA	IA	early	133	Large
148	1122SPD-1	SI	Unknown	IA	early	0	Small
149	6254Main Ash Pond	SI	NA	IA	early	229	Large
150	6664Bottom Ash Pond	SI	Clay	IA	early	588	Large
151	6664Louisa Surface Impoundment	SI	Clay	IA	early	242	Large
152	856Ash Pond	SI	NA	IL	late	1,800	Large
153	856Pond 2 - Ash Pond Settling	SI	NA	IL	late	448	Large
154	856Pond 3 - Clarification Pond	SI	NA	IL	late	322	Large
155	861Gypsum Management Facility Recycle Pond	SI	Yes	IL	late	243	Large
156	874SPD-1	SI	NA	IL	late	2,252	Small
157	874SPD-2	SI	NA	IL	late	27	Large
158	876Slag Field	SI	NA	IL	late	3,560	Large
159	879SPD-1	SI	NA	IL	late	114	Large
160	879SPD-2	SI	NA	IL	late	23	Large

Exhibit O-2

Detailed Information Used to Estimate Benefits for Universe of Surface Impoundments

Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring	Capacity (Acre Feet)	Size Class
161	879SPD-3	SI	NA	IL	late	6	Small
162	883SPD-1	SI	Yes	IL	late	110	Large
163	883SPD-2	SI	Yes	IL	late	111	Large
164	887Ash Pond	SI	NA	IL	late	3,833	Large
165	889Ash Pond System	SI	Unknown	IL	late	3,957	Large
166	891East Ash Pond	SI	Yes	IL	late	2,625	Large
167	891North Ash Pond System	SI	Unknown	IL	late	25	Small
168	892Ash Pond System (2 cells)	SI	Unknown	IL	late	563	Large
169	898East Ash Pond (2 cells)	SI	Yes	IL	late	435	Large
170	898West Ash Pond (2 cells) Cells 2E and 3	SI	Clay	IL	late	210	Large
171	963Dallman Ash Pond	SI	NA	IL	late	682	Large
172	976Fly Ash Disposal Pond	SI	Unknown	IL	late	630	Large
173	976Pond 1	SI	Unknown	IL	late	126	Large
174	976Pond 2	SI	Unknown	IL	late	210	Large
175	976Pond 3	SI	Unknown	IL	late	280	Large
176	976Pond 3A	SI	Unknown	IL	late	280	Large
177	976Pond 4	SI	Unknown	IL	late	770	Large
178	976Pond A-1	SI	Unknown	IL	late	448	Large
179	976Pond S-1	SI	Unknown	IL	late	994	Large
180	976Pond S-2	SI	Unknown	IL	late	350	Large
181	976Pond S-3	SI	Unknown	IL	late	280	Large
182	976Pond S-6	SI	Unknown	IL	late	224	Large
183	976South Fly Ash Pond	SI	Unknown	IL	late	1,442	Large
184	6016Recycle Pond	SI	Clay	IL	late	182	Large
185	6017Primary Ash Pond	SI	NA	IL	late	9,250	Large
186	6017Secondary Ash Pond	SI	NA	IL	late	83	Large
187	6238SPD-1	SI	NA	IL	late	6	Small
188	983South Fly Ash Runoff Pond Site 16	SI	NA	IN	early	560	Large
189	983West Bottom Ash Pond Site 16 (Regn 5)	SI	NA	IN	early	3,600	Large
190	988Boiler Slag Pond (U-4)	SI	Unknown	IN	early	820	Large
191	988Bottom Ash Complex	SI	NA	IN	early	1,645	Large
192	988Fly Ash Pond	SI	Yes	IN	early	1,076	Large

Exhibit O-2

Detailed Information Used to Estimate Benefits for Universe of Surface Impoundments

Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring	Capacity (Acre Feet)	Size Class
193	988Fly Ash Pond - Clear Pond and Original (Lower Pond) Dike	SI	Yes	IN	early	168	Large
194	988Fly Ash Pond - Upper Pond	SI	NA	IN	early	668	Large
195	990Pond 1	SI	NA	IN	early	92	Large
196	990Pond 2	SI	NA	IN	early	505	Large
197	990Pond 3	SI	NA	IN	early	8	Small
198	990Pond 4	SI	NA	IN	early	304	Large
199	990Ponds 2A/2B	SI	NA	IN	early	43	Large
200	991A Pond	SI	NA	IN	early	400	Large
201	991B Pond	SI	NA	IN	early	177	Large
202	991C Pond	SI	NA	IN	early	102	Large
203	991D Pond	SI	NA	IN	early	370	Large
204	994Pond A - Active	SI	NA	IN	early	930	Large
205	994Pond A - Discharge	SI	NA	IN	early	108	Large
206	995Bottom Ash Pond	SI	Unknown	IN	early	2	Small
207	995Primary 1	SI	Unknown	IN	early	41	Large
208	995Primary 2	SI	Unknown	IN	early	47	Large
209	995Secondary 1	SI	Unknown	IN	early	18	Small
210	995Secondary 2	SI	Unknown	IN	early	30	Large
211	997Bottom Ash Area	SI	Unknown	IN	early	1	Small
212	997Final Settling Pond	SI	Unknown	IN	early	85	Large
213	997Primary 1	SI	Unknown	IN	early	36	Large
214	997Primary 2	SI	Unknown	IN	early	44	Large
215	997Secondary 1	SI	Unknown	IN	early	3	Small
216	997Secondary 2	SI	Unknown	IN	early	3	Small
217	1001Ash Disposal Area #1	SI	NA	IN	early	260	Large
218	1001Lined Ash Disposal Pond - Cell #1	SI	Yes	IN	early	1,400	Large
219	1001Primary Ash Settling Basin	SI	NA	IN	early	225	Large
220	1001Secondary Ash Settling Basin	SI	NA	IN	early	36	Large
221	1004Primary Ash Pond	SI	NA	IN	early	170	Large
222	1004Secondary Ash Pond	SI	NA	IN	early	7	Small
223	1008Ash Pond A	SI	NA	IN	early	936	Large
224	1008Secondary Ash Pond	SI	NA	IN	early	63	Large

Exhibit O-2

Detailed Information Used to Estimate Benefits for Universe of Surface Impoundments

Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring	Capacity (Acre Feet)	Size Class
225	1010Primary Ash Pond Cell A	SI	NA	IN	early	1,350	Large
226	1010Primary Ash Pond Cell B	SI	NA	IN	early	530	Large
227	1010Secondary Ash Pond	SI	NA	IN	early	73	Large
228	1010South Ash Pond	SI	Yes	IN	early	1,450	Large
229	1012East Pond	SI	NA	IN	early	372	Large
230	1040SPD-5	SI	NA	IN	early	1	Small
231	1043Bottom Ash Pond	SI	NA	IN	early	40	Large
232	1043Fly Ash Pond 1	SI	NA	IN	early	140	Large
233	1043Fly Ash Pond 2	SI	NA	IN	early	224	Large
234	1043Fly Ash Pond 3	SI	NA	IN	early	350	Large
235	1043Pond 1	SI	NA	IN	early	84	Large
236	1043Pond 2	SI	Unknown	IN	early	140	Large
237	1043Pond 3	SI	Unknown	IN	early	140	Large
238	1043Pond 4	SI	Unknown	IN	early	350	Large
239	6085FGD Landfill Stormwater Runoff Pond	SI	NA	IN	early	12	Small
240	6085Gypsum Storage (Units 14&15)A	SI	NA	IN	early	630	Large
241	6085Gypsum Storage (Units 14&15)B	SI	NA	IN	early	133	Large
242	6085Material Storage Runoff Basin	SI	NA	IN	early	48	Small
243	6085Metal Cleaning Waste Basin	SI	NA	IN	early	48	Small
244	6085Recycle Basin	SI	NA	IN	early	372	Large
245	6113East Pond #1	SI	NA	IN	early	1,733	Large
246	6113East Pond #2	SI	NA	IN	early	1,733	Large
247	6113East Pond #3	SI	NA	IN	early	3,325	Large
248	6113East Settling Basin	SI	NA	IN	early	743	Large
249	6113North Ash Pond	SI	NA	IN	early	350	Large
250	6113North Settling Basin	SI	NA	IN	early	150	Large
251	6137Lower Ash Pond	SI	NA	IN	early	930	Large
252	6137Upper Ash Pond	SI	NA	IN	early	2,417	Large
253	6166Bottom Ash Complex	SI	NA	IN	early	1,640	Large
254	6705EPRI 9	SI	Unknown	IN	early	2,789	Large
255	1239Industrial Landfill-East and West Ponds	SI	NA	KS	early	992	Large
256	1241Bottom Ash Settling Pond	SI	Clay	KS	early	12	Small

Exhibit O-2

Detailed Information Used to Estimate Benefits for Universe of Surface Impoundments

Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring	Capacity (Acre Feet)	Size Class
257	1241Scrubber Sludge Ponds	SI	Clay	KS	early	9,298	Large
258	1250Area 1	SI	NA	KS	early	71	Large
259	1250Area 2	SI	NA	KS	early	155	Large
260	1250Area 3	SI	Clay	KS	early	273	Large
261	1250Area 4	SI	NA	KS	early	185	Large
262	1252Area 1	SI	NA	KS	early	20	Small
263	1252Area 2	SI	NA	KS	early	12	Small
264	6064N/A	SI	Clay	KS	early	124	Large
265	6068Bottom Ash Lake Dam	SI	NA	KS	early	3,000	Large
266	6068Bottom Ash Pond Dam	SI	NA	KS	early	550	Large
267	6068Bottom Ash Settling Pond	SI	Unknown	KS	early	988	Large
268	1353Bottom Ash Complex	SI	NA	KY	early	40	Large
269	1353Fly Ash	SI	Unknown	KY	early	8,302	Large
270	1353Horseford Run Dam	SI	Clay	KY	early	2,464	Large
271	1355Ash Pond	SI	Yes	KY	early	1,052	Large
272	1355Auxiliary Pond	SI	Yes	KY	early	515	Large
273	1356Ash Treatment Basin #1	SI	NA	KY	early	4,339	Large
274	1356Ash Treatment Basin #2	SI	NA	KY	early	7,190	Large
275	1356Gypsum Stack Surge/Reclaim Pond	SI	Clay	KY	early	112	Large
276	1356Gypsum Stacking Facility	SI	NA	KY	early	2,758	Large
277	1356Secondary Ash Treatment Basin	SI	Unknown	KY	early	56	Large
278	1357Ash Pond Number 2	SI	NA	KY	early	322	Large
279	1357Finishing Pond Number 3	SI	NA	KY	early	28	Large
280	1357Former Ash Pond	SI	NA	KY	early	84	Large
281	1357Main Ash Pond	SI	NA	KY	early	775	Large
282	1357Scrubber Pond	SI	NA	KY	early	150	Large
283	1361Ash Pond	SI	NA	KY	early	182	Large
284	1361Secondary Ash Pond	SI	NA	KY	early	17	Small
285	1363Basin Pond	SI	NA	KY	early	70	Large
286	1363Clearwell Pond	SI	Unknown	KY	early	14	Small
287	1363Dead Storage Pond	SI	NA	KY	early	70	Large
288	1363Emergency Pond	SI	Unknown	KY	early	28	Large

Exhibit O-2

Detailed Information Used to Estimate Benefits for Universe of Surface Impoundments

Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring	Capacity (Acre Feet)	Size Class
289	1363Main Ash Pond/E-Pond	SI	NA	KY	early	868	Large
290	1364Ash Pond	SI	NA	KY	early	602	Large
291	1364Clearwell Pond	SI	Unknown	KY	early	28	Large
292	1364Construction Run Off Pond	SI	Unknown	KY	early	42	Large
293	1364Dead Storage Pond	SI	Unknown	KY	early	28	Large
294	1364Emergency Pond	SI	Unknown	KY	early	14	Small
295	1374SPD-1	SI	NA	KY	early	24	Large
296	1374SPD-2	SI	NA	KY	early	25	Small
297	1374SPD-4	SI	Yes	KY	early	8	Small
298	1374SPD-6	SI	NA	KY	early	0	Small
299	1378Fly Ash Extension Area Pond	SI	Unknown	KY	early	3,935	Large
300	1378Scrubber Sludge Complex	SI	Unknown	KY	early	532	Small
301	1379Ash Pond	SI	Unknown	KY	early	3,099	Large
302	1379Consolidated Waste Dry Stack	SI	Unknown	KY	early	20,575	Large
303	1381Active Ash Pond A	SI	NA	KY	early	1,180	Large
304	1381Inactive Ash Pond C	SI	NA	KY	early	273	Large
305	1381New Ash Pond	SI	Unknown	KY	early	2,417	Large
306	1382Ash Pond No. 0855	SI	NA	KY	early	174	Large
307	1382Green Ash Pond	SI	NA	KY	early	298	Large
308	1385Dale Ash Pond #2	SI	NA	KY	early	112	Large
309	1385Dale Ash Pond #3	SI	Unknown	KY	early	22	Large
310	1385Dale Ash Pond #4	SI	NA	KY	early	143	Large
311	6018East Bend Station Unit 1	SI	NA	KY	early	1,277	Large
312	6018FGD Pond East	SI	Unknown	KY	early	51	Large
313	6018FGD Pond West	SI	Unknown	KY	early	45	Large
314	6041Spurlock Ash Pond	SI	Clay	KY	early	1,085	Large
315	6071Coal Combustion Waste Pond	SI	Clay	KY	early	4,841	Large
316	6639Ash Pond Dam #0980	SI	NA	KY	early	298	Large
317	51Ash Basin No. 1	SI	Clay	LA	late	578	Large
318	51Ash Basin No. 2	SI	Clay	LA	late	501	Large
319	51Auxiliary Surge Pond	SI	Clay	LA	late	2	Small
320	51Landfill Storm Water/Leachate	SI	Clay	LA	late	18	Small

Exhibit O-2

Detailed Information Used to Estimate Benefits for Universe of Surface Impoundments

Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring	Capacity (Acre Feet)	Size Class
321	51Secondary Basin	SI	NA	LA	late	75	Large
322	51Surge Pond No. 1	SI	Clay	LA	late	29	Large
323	51Surge Pond No. 2	SI	Clay	LA	late	18	Small
324	6055Bottom Ash Unit	SI	Clay	LA	late	1,188	Large
325	6055Fly Ash Unit	SI	Clay	LA	late	1,750	Large
326	6055Water Treatment Unit	SI	Clay	LA	late	585	Large
327	6190Bottom Ash Pond	SI	Clay	LA	late	641	Large
328	6190Fly Ash Pond	SI	Clay	LA	late	670	Large
329	6190Leachate Pond	SI	Yes	LA	late	112	Large
330	1619SPD-4	SI	Yes	MA	never	3	Small
331	1619SPD-5	SI	Yes	MA	never	6	Small
332	1619SPD-6	SI	Yes	MA	never	6	Small
333	602SPD-5	SI	Yes	MD	early	4	Small
334	602SPD-6	SI	Yes	MD	early	4	Small
335	1570Ash Pond #3	SI	NA	MD	early	104	Large
336	1570Ash Pond #4	SI	Yes	MD	early	218	Large
337	1702DE Karn 1 and 2 Solid Waste Disposal Area	SI	NA	MI	never	182	Large
338	1702Pond A	SI	NA	MI	never	4,423	Large
339	1720East 7 & 8 Ponds	SI	Unknown	MI	never	1,904	Large
340	1720J.C. Weadock Fly Ash Dam	SI	Clay	MI	never	182	Large
341	1720Weadock Landfill Embankment	SI	Clay	MI	never	182	Large
342	1720West A - E Ponds	SI	Unknown	MI	never	2,184	Large
343	1723Pond 1	SI	NA	MI	never	148	Large
344	1723Pond 2	SI	NA	MI	never	135	Large
345	1723Pond 6	SI	NA	MI	never	1,054	Large
346	1723Ponds 3-5	SI	Unknown	MI	never	1,489	Large
347	1731Pond	SI	Unknown	MI	never	182	Large
348	1733Bottom Ash Basin	SI	Unknown	MI	never	620	Large
349	1733Fly Ash Basin	SI	NA	MI	never	18,595	Large
350	1740SPD-1	SI	NA	MI	never	18	Small
351	1743Pond	SI	Unknown	MI	never	0	Small
352	1745Pond	SI	Unknown	MI	never	0	Small

Exhibit O-2

Detailed Information Used to Estimate Benefits for Universe of Surface Impoundments

Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring	Capacity (Acre Feet)	Size Class
353	1825SPD-1	SI	Clay	MI	never	2	Small
354	1825SPD-2	SI	Clay	MI	never	2	Small
355	1830SPD-1	SI	NA	MI	never	6	Small
356	1832Unit 1	SI	Unknown	MI	never	198	Large
357	6034Pond	SI	Unknown	MI	never	0	Small
358	1891Cell E	SI	Yes	MN	early	174	Large
359	1893Complex: Pond 3, 4, and Bottom Ash Pond	SI	Clay	MN	early	11,236	Large
360	1893Wastewater Treatment Plant Pond	SI	Clay	MN	early	9	Small
361	1904Settling Ponds 1-4	SI	NA	MN	early	218	Large
362	6090Bottom Ash Pond	SI	Clay	MN	early	620	Large
363	6090Pond 3 N	SI	Yes	MN	early	1,860	Large
364	6090Pond No. 1	SI	Clay	MN	early	3,099	Large
365	6090Pond No. 2	SI	Clay	MN	early	6,198	Large
366	6090Recycle Basin	SI	Unknown	MN	early	98	Large
367	6090Unit No. 3 Dry Ash Landfill Basin	SI	Unknown	MN	early	42	Large
368	2076Ash Impoundment	SI	Unknown	MO	late	1,288	Large
369	2076Lower Pond	SI	NA	MO	late	882	Large
370	2076Upper Pond	SI	NA	MO	late	246	Large
371	2079Scrubber Waste Settling Pond	SI	Unknown	MO	late	2	Small
372	2080Ash Settling Pond	SI	Unknown	MO	late	13	Small
373	2080North Ash Pond	SI	Unknown	MO	late	23	Large
374	2080South Ash Pond	SI	Unknown	MO	late	38	Large
375	2094Fly Ash Settling Pond	SI	Clay	MO	late	224	Large
376	2094Slag Settling Pond	SI	NA	MO	late	14	Small
377	2098Settling Pond	SI	Unknown	MO	late	5	Small
378	2103Bottom Ash Pond	SI	NA	MO	late	12,000	Large
379	2103Fly Ash Pond	SI	Yes	MO	late	1,900	Large
380	2104Bottom Ash Pond (3)	SI	NA	MO	late	280	Large
381	2104New Fly Ash Pond	SI	Yes	MO	late	230	Large
382	2104Old Fly Ash Pond	SI	Yes	MO	late	300	Large
383	2107Bottom Ash Pond	SI	NA	MO	late	2,100	Large
384	2107Fly Ash Pond	SI	Yes	MO	late	960	Large

Exhibit O-2

Detailed Information Used to Estimate Benefits for Universe of Surface Impoundments

Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring	Capacity (Acre Feet)	Size Class
385	2123SPD-1	SI	NA	MO	late	42	Large
386	2132Bottom Ash Pond	SI	NA	MO	late	133	Large
387	2132North Fly Ash Pond	SI	NA	MO	late	252	Large
388	2161Pond	SI	Unknown	MO	late	182	Large
389	2167Ash Pond 1	SI	NA	MO	late	570	Large
390	2167Ash Pond 2	SI	Yes	MO	late	1,351	Large
391	2167Slag Pond 1	SI	NA	MO	late	1,137	Large
392	2167Slag Pond 2	SI	NA	MO	late	14	Small
393	2168Ash - 2 Landfill	SI	Unknown	MO	late	1,446	Large
394	2168Ash -3 Landfill	SI	Unknown	MO	late	1,050	Large
395	2168Ash Pond Cell 1 - Upper	SI	Unknown	MO	late	98	Large
396	2168Ash Pond Cell 2 - Middle	SI	NA	MO	late	31	Small
397	2168Ash Pond Cell 3 - Lowest	SI	Unknown	MO	late	50	Small
398	2168Ash Pond Slag Dewatering	SI	NA	MO	late	10	Small
399	2169SPD-2	SI	NA	MO	late	25	Large
400	2171SPD-1	SI	Unknown	MO	late	0	Small
401	6155Ash Pond	SI	NA	MO	late	7,000	Large
402	6195SPD-1	SI	Clay	MO	late	1	Small
403	6195SPD-2	SI	Clay	MO	late	1	Small
404	6768Bottom Ash Pond	SI	Clay	MO	late	891	Large
405	6768Fly Ash Pond	SI	Clay	MO	late	560	Large
406	2049Ash Pond	SI	NA	MS	late	317	Small
407	6061SPD-4	SI	Unknown	MS	late	182	Large
408	6061SPD-5	SI	Unknown	MS	late	182	Large
409	6073EPRI 7	SI	Unknown	MS	late	281	Large
410	55076SPD-1	SI	Unknown	MS	late	182	Large
411	2187SPD-1	SI	Unknown	MT	early	182	Large
412	2187SPD-2	SI	Unknown	MT	early	182	Large
413	6076Units 1 & 2 A Pond	SI	NA	MT	early	245	Large
414	6076Units 1 & 2 B Fly Ash Pond	SI	Unknown	MT	early	196	Large
415	6076Units 1 & 2 Bottom Ash Pond	SI	Yes	MT	early	73	Large
416	6076Units 1 & 2 Stage Two Evaporation Ponds (STEP)	SI	Yes	MT	early	4,370	Large

Exhibit O-2

Detailed Information Used to Estimate Benefits for Universe of Surface Impoundments

Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring	Capacity (Acre Feet)	Size Class
417	6076Units 3 & 4 Bottom Ash Pond	SI	Unknown	MT	early	38	Small
418	6076Units 3 & 4 Effluent Holding Pond (EHP)	SI	NA	MT	early	17,000	Large
419	6089SPD-1	SI	Clay	MT	early	11	Small
420	6089SPD-2	SI	Clay	MT	early	2	Small
421	6089SPD-3	SI	Clay	MT	early	11	Small
422	6089SPD-4	SI	Clay	MT	early	2	Small
423	6089SPD-5	SI	Yes	MT	early	182	Large
424	27061964 Pond	SI	Yes	NC	early	1,380	Large
425	27061982 Pond	SI	NA	NC	early	1,400	Large
426	27081978 Ash Pond	SI	NA	NC	early	1,161	Large
427	27081985 Ash Pond	SI	NA	NC	early	1,764	Large
428	27091980 Pond	SI	Unknown	NC	early	0	Small
429	2709Active Ash Pond	SI	NA	NC	early	1,980	Large
430	2712Ash Pond	SI	NA	NC	early	4,800	Large
431	2712FGD Flush Pond	SI	Yes	NC	early	53	Large
432	2712FGD Settling Pond	SI	Yes	NC	early	420	Large
433	2712West Ash Pond Dam & Dikes 1, 2,,& 4	SI	Unknown	NC	early	33,600	Large
434	27131971 Pond	SI	NA	NC	early	921	Large
435	27131984 Pond	SI	Clay	NC	early	1,364	Large
436	2718Active Ash Basin	SI	NA	NC	early	5,915	Large
437	2718East Dike - Active Ash Basin	SI	NA	NC	early	0	Small
438	2718North Dike - Active Ash Basin	SI	NA	NC	early	0	Small
439	2720Additional Primary Cell Basin	SI	NA	NC	early	2,645	Large
440	2720Old Primary Cell	SI	NA	NC	early	1,610	Large
441	2720Secondary Pond	SI	NA	NC	early	510	Large
442	2721Active Ash Pond	SI	NA	NC	early	5,025	Large
443	2727Active Ash Pond	SI	NA	NC	early	6,885	Large
444	2732Primary Ash Disposal Pond	SI	NA	NC	early	1,640	Large
445	2732Secondary Pond	SI	NA	NC	early	980	Large
446	62501982 Pond	SI	NA	NC	early	4,100	Large
447	8042Active Ash Pond	SI	NA	NC	early	12,654	Large
448	2817Ash Pond #1	SI	NA	ND	early	744	Large

Exhibit O-2

Detailed Information Used to Estimate Benefits for Universe of Surface Impoundments

Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring	Capacity (Acre Feet)	Size Class
449	2817Ash Pond #2	SI	NA	ND	early	924	Large
450	2817Ash Pond #3	SI	NA	ND	early	12	Small
451	282330 Year Ponds (Cell 2)	SI	Clay	ND	early	1,252	Large
452	2823Cell 1	SI	Clay	ND	early	0	Small
453	2823Horseshoe Pit Evaporation Pond	SI	Unknown	ND	early	34	Large
454	2823Unit 1 Alternative Bottom Ash Pond	SI	Clay	ND	early	25	Large
455	2824Middle Bottom Ash Pond/Retention Cell	SI	Unknown	ND	early	38	Large
456	2824North Bottom Ash Pond/Cell	SI	Unknown	ND	early	37	Large
457	6030Ash Pond 91	SI	Unknown	ND	early	249	Small
458	6030Upstream Raise/Ash Pond 92/SW Section 16	SI	Unknown	ND	early	769	Large
459	8222Ash Pond	SI	Unknown	ND	early	40	Large
460	8222Nelson Pond	SI	Unknown	ND	early	92	Large
461	8222Sluice Pond	SI	Unknown	ND	early	5	Small
462	60SPD-1	SI	NA	NE	never	169	Large
463	2291SPD-1	SI	Yes	NE	never	15	Small
464	2291SPD-2	SI	Yes	NE	never	11	Small
465	6096SPD-1	SI	NA	NE	never	97	Large
466	6096SPD-2	SI	NA	NE	never	111	Large
467	2364SPD-3	SI	NA	NH	never	1	Small
468	2364SPD-4	SI	NA	NH	never	10	Small
469	87Emergency Scrubber Pond	SI	Unknown	NM	never	3	Small
470	87Evaporation Pond 1a + 1b	SI	Unknown	NM	never	14	Small
471	87Evaporation Ponds 2-5	SI	Unknown	NM	never	182	Large
472	87Management Units 3 & 4 Bottom Ash	SI	Unknown	NM	never	96	Large
473	2442Lined Ash Impoundment	SI	Yes	NM	never	2,399	Large
474	2442Lined Water Impoundment	SI	Yes	NM	never	435	Large
475	2442Low Volume Waste Water Pond	SI	Unknown	NM	never	137	Large
476	2442Low Volume Waste Water System Decant Cells	SI	Unknown	NM	never	435	Large
477	2442Upper Retention Sump	SI	Unknown	NM	never	11	Small
478	2324Pond B1	SI	Yes	NV	late	193	Large
479	2324Pond B2	SI	Yes	NV	late	148	Large
480	2324Pond B3	SI	Yes	NV	late	90	Large

Exhibit O-2

Detailed Information Used to Estimate Benefits for Universe of Surface Impoundments

Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring	Capacity (Acre Feet)	Size Class
481	2324Pond E1	SI	Yes	NV	late	115	Large
482	2324Pond E2	SI	Yes	NV	late	165	Large
483	2324Pond F	SI	Yes	NV	late	37	Large
484	2527SPD-1	SI	NA	NY	early	13	Small
485	2527SPD-2	SI	NA	NY	early	6	Small
486	2549North Equalization Basin	SI	Unknown	NY	early	9	Small
487	2549South Equalization Basin	SI	Unknown	NY	early	6	Small
488	2549South Settling Pond System	SI	Unknown	NY	early	48	Large
489	2554Equalization Basin	SI	Unknown	NY	early	2	Small
490	2554Settling Pond System	SI	Unknown	NY	early	12	Small
491	6082SPD-5	SI	Unknown	NY	early	182	Large
492	2828Bottom Ash Complex	SI	NA	OH	early	350	Large
493	2828Fly Ash Reservoir 2	SI	NA	OH	early	11,350	Large
494	2830Ash Pond B	SI	NA	OH	early	280	Large
495	2830Ash Pond C	SI	NA	OH	early	1,400	Large
496	2832Ash Basin A	SI	NA	OH	early	803	Large
497	2832Ash Basin B	SI	NA	OH	early	515	Large
498	2835SPD-1	SI	NA	OH	early	2	Small
499	2836SPD-1	SI	NA	OH	early	1	Small
500	2836SPD-2	SI	NA	OH	early	1	Small
501	2837SPD-1	SI	NA	OH	early	3	Small
502	2838SPD-1	SI	NA	OH	early	3	Small
503	2840Ash Pond Complex	SI	NA	OH	early	865	Large
504	2843[blank]	SI	Unknown	OH	early	275	Large
505	2848East Primary Settling Pond	SI	NA	OH	early	76	Large
506	2848Secondary Settling Pond	SI	NA	OH	early	6	Small
507	2848West Primary Settling Pond	SI	NA	OH	early	110	Large
508	2850Ash Pond No. 10	SI	Clay	OH	early	930	Large
509	2850Ash Pond No. 3A	SI	Clay	OH	early	1,302	Large
510	2866SPD-1	SI	NA	OH	early	21	Large
511	2866SPD-2	SI	NA	OH	early	28	Large
512	2872Lower Fly Ash Dam	SI	NA	OH	early	660	Large

Exhibit O-2

Detailed Information Used to Estimate Benefits for Universe of Surface Impoundments

Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring	Capacity (Acre Feet)	Size Class
513	2872Middle Fly Ash Pond	SI	NA	OH	early	1,370	Large
514	2872Unit 1-4 Bottom Ash Pond Dam	SI	NA	OH	early	100	Large
515	2872Upper Fly Ash Pond	SI	NA	OH	early	5,250	Large
516	2876Bottom Ash Pond	SI	NA	OH	early	1,435	Large
517	2876South Fly Ash Pond	SI	NA	OH	early	2,500	Large
518	2878SPD-1	SI	NA	OH	early	5	Small
519	6019Wastewater Pond Complex	SI	Clay	OH	early	75	Small
520	6031Bottom Ash Pond	SI	Unknown	OH	early	1,903	Large
521	6031Fly Ash Pond	SI	Unknown	OH	early	11,004	Large
522	8102Bottom Ash Pond	SI	NA	OH	early	1,530	Large
523	8102Stingy Run Ash Disposal Pond	SI	NA	OH	early	23,365	Large
524	165SPD-12	SI	NA	OK	late	1	Small
525	2952SPD-1	SI	Clay	OK	late	1,676	Large
526	2952SPD-3	SI	NA	OK	late	64	Large
527	2952SPD-6	SI	Unknown	OK	late	182	Large
528	2963Bottom Ash Pond	SI	Clay	OK	late	700	Large
529	6095SPD-4	SI	Clay	OK	late	124	Large
530	6772North Bottom Ash Unit	SI	Clay	OK	late	344	Large
531	6772North Fly Ash	SI	Clay	OK	late	332	Large
532	6772South Bottom Ash	SI	Clay	OK	late	344	Large
533	6772South Fly Ash Unit	SI	Clay	OK	late	332	Large
534	3098SPD-1	SI	Unknown	PA	early	29	Small
535	3098SPD-2	SI	Unknown	PA	early	182	Large
536	3098SPD-4	SI	Unknown	PA	early	7	Small
537	3113SPD-1	SI	NA	PA	early	3	Small
538	3113SPD-2	SI	NA	PA	early	3	Small
539	3118SPD-3	SI	Clay	PA	early	6	Small
540	3118SPD-4	SI	Clay	PA	early	6	Small
541	3118SPD-5	SI	Clay	PA	early	6	Small
542	3118SPD-6	SI	Clay	PA	early	6	Small
543	3122Ash Disposal Site - Polishing Pond	SI	Unknown	PA	early	2	Small
544	3122Ash Disposal Site - Treatment Pond #1	SI	Unknown	PA	early	1	Small

Exhibit O-2

Detailed Information Used to Estimate Benefits for Universe of Surface Impoundments

Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring	Capacity (Acre Feet)	Size Class
545	3122Ash Disposal Site - Treatment Pond #2	SI	Unknown	PA	early	1	Small
546	3122Ash Recycle Pond #1	SI	Unknown	PA	early	4	Small
547	3122Ash Recycle Pond #2	SI	Unknown	PA	early	5	Small
548	3122Ash Recycle Pond #3	SI	Unknown	PA	early	5	Small
549	3122Ash Recycle Pond #4	SI	Unknown	PA	early	5	Small
550	3122Coal Refuse Disposal Site - Stage I & II Pond	SI	Unknown	PA	early	13	Small
551	3122Coal Refuse Disposal Site - Stage III & IV Pond	SI	Unknown	PA	early	26	Large
552	3122Coal Refuse Disposal Site - Storage Pond #1	SI	Unknown	PA	early	2	Small
553	3122Coal Refuse Disposal Site - Storage Pond #2	SI	Unknown	PA	early	11	Small
554	3131SPD-1	SI	Yes	PA	early	13	Small
555	3131SPD-2	SI	Yes	PA	early	12	Small
556	3136SPD-10	SI	Yes	PA	early	129	Large
557	3136SPD-13	SI	Unknown	PA	early	182	Large
558	3136SPD-14	SI	Unknown	PA	early	182	Large
559	3136SPD-7	SI	Clay	PA	early	4	Small
560	3136SPD-8	SI	Clay	PA	early	4	Small
561	3136SPD-9	SI	Clay	PA	early	4	Small
562	3138SPD-1	SI	NA	PA	early	16	Small
563	3138SPD-2	SI	NA	PA	early	6	Small
564	3140Ash Basin No.6	SI	Unknown	PA	early	2,600	Large
565	3140Equalizatipond	SI	Unknown	PA	early	5	Small
566	3149Ash Basin No. 1	SI	Unknown	PA	early	5,070	Large
567	3152Residual Waste Ash Basin No. 1	SI	NA	PA	early	1,139	Large
568	3179SPD-1	SI	NA	PA	early	15	Small
569	3179SPD-2	SI	NA	PA	early	15	Small
570	6094East HDS (Decommissioned in 2003) (Add this unit to DB)	SI	NA	PA	early	182	Large
571	6094Little Blue Run Dam	SI	NA	PA	early	65,000	Large
572	6094North LDS Pond (N-LDS)	SI	NA	PA	early	38	Large
573	6094South LDS Pond (S-LDS)	SI	NA	PA	early	35	Large
574	6094West HDS Pond (W-HPDS)	SI	NA	PA	early	39	Large
575	8226SPD-4	SI	Clay	PA	early	5	Small
576	8226SPD-5	SI	Clay	PA	early	3	Small

Exhibit O-2

Detailed Information Used to Estimate Benefits for Universe of Surface Impoundments

Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring	Capacity (Acre Feet)	Size Class
577	130Bottom Ash 1	SI	Clay	SC	early	230	Large
578	130Bottom Ash 2	SI	Clay	SC	early	1,158	Large
579	130Gypsum Pond	SI	Clay	SC	early	6	Small
580	3251Pond	SI	NA	SC	early	410	Large
581	3264Primary Active Ash Pond	SI	NA	SC	early	779	Large
582	3264Secondary Ash Pond	SI	NA	SC	early	391	Large
583	3280Ash Pond	SI	NA	SC	early	1,407	Large
584	3280Inactive Ash Pond	SI	NA	SC	early	1,000	Large
585	3280Polishing Pond	SI	NA	SC	early	49	Large
586	3295Ash Pond	SI	NA	SC	early	126	Large
587	3295Ash Pond 1	SI	Unknown	SC	early	11	Small
588	3295Ash Pond 2	SI	Unknown	SC	early	7	Small
589	3297Ash Pond No. 1	SI	NA	SC	early	1,200	Large
590	3297Ash Pond No. 2	SI	NA	SC	early	1,200	Large
591	3319Ash Pond A	SI	NA	SC	early	982	Large
592	3319Ash Pond B	SI	NA	SC	early	245	Small
593	6249Ash Pond A	SI	NA	SC	early	807	Large
594	6249Ash Pond B	SI	NA	SC	early	537	Large
595	6249South Ash Pond	SI	NA	SC	early	1,129	Large
596	6249Unit 2 Slurry Pond	SI	NA	SC	early	416	Large
597	6249Unit 3 & 4 Slurry Pond	SI	NA	SC	early	1,700	Large
598	6249West Ash Pond	SI	NA	SC	early	1,178	Large
599	3325SPD-1	SI	Clay	SD	never	1	Small
600	6098SPD-2	SI	NA	SD	never	21	Large
601	3393East Ash Disposal	SI	Unknown	TN	early	1,100	Large
602	3393East Ash Stilling Pond	SI	Unknown	TN	early	180	Large
603	3396Bottom Ash Disposal Area 1	SI	Unknown	TN	early	543	Large
604	3396Dry Fly Ash Disposal Area	SI	Unknown	TN	early	2,975	Large
605	3396Fly Ash Pond & Stilling Basin Area 2	SI	Unknown	TN	early	1,674	Large
606	3396Gypsum Disposal Area 2A	SI	Unknown	TN	early	1,700	Large
607	3399Ash Pond	SI	Unknown	TN	early	1,240	Large
608	3399Dry Ash Stack	SI	Unknown	TN	early	7,810	Large

Exhibit O-2

Detailed Information Used to Estimate Benefits for Universe of Surface Impoundments

Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring	Capacity (Acre Feet)	Size Class
609	3399Gypsum Storage Area (North/South)	SI	Unknown	TN	early	12,397	Large
610	3403Bottom Ash Pond A	SI	Unknown	TN	early	4,390	Large
611	3403Fly Ash Pond E	SI	Unknown	TN	early	4,401	Large
612	3403Stilling Pond B, C, D	SI	Unknown	TN	early	372	Large
613	3405Bottom Ash Pond	SI	Unknown	TN	early	744	Large
614	3405Dry Ash Stack	SI	Unknown	TN	early	2,355	Large
615	3406Ash Disposal Area 2	SI	Unknown	TN	early	2,702	Large
616	3406DuPont Road Dredge Cell	SI	NA	TN	early	308	Large
617	3407Main Ash Pond	SI	Unknown	TN	early	8,907	Large
618	3407Stilling Pond	SI	Unknown	TN	early	290	Large
619	127Pond #23	SI	Unknown	TX	late	333	Large
620	127Sludge Pond	SI	Unknown	TX	late	565	Large
621	127Wastewater Evaporation Pond 6	SI	Clay	TX	late	1,044	Large
622	298Bottom Ash Cooling Pond	SI	Unknown	TX	late	50	Large
623	298FGD Emergency Pond E	SI	Unknown	TX	late	31	Large
624	3470Flue Gas Desulfurization Emergency Pond (E-Pond)	SI	Unknown	TX	late	2	Small
625	3470Unit 5 Bottom Ash Overflow Basin	SI	Unknown	TX	late	182	Large
626	3470Unit 6 Bottom Ash Overflow Basin	SI	Unknown	TX	late	182	Large
627	3470Unit 7 Bottom Ash Overflow Basin	SI	Unknown	TX	late	182	Large
628	3470Unit 8 Bottom Ash Overflow Basin	SI	Unknown	TX	late	182	Large
629	3497SPD-4	SI	Clay	TX	late	227	Large
630	3497SPD-5	SI	NA	TX	late	5	Small
631	6136SPD-1	SI	Clay	TX	late	138	Large
632	6136SPD-2	SI	Clay	TX	late	138	Large
633	6136SPD-3	SI	Clay	TX	late	106	Large
634	6136SPD-5	SI	Yes	TX	late	122	Large
635	6139Active Bottom Ash Storage	SI	Yes	TX	late	270	Large
636	6139Primary Ash Pond	SI	NA	TX	late	307	Small
637	6139Secondary Ash Pond	SI	NA	TX	late	37	Large
638	6146SPD-3	SI	Yes	TX	late	211	Small
639	6146SPD-4	SI	Yes	TX	late	249	Small
640	6146SPD-5	SI	Yes	TX	late	217	Large

Exhibit O-2

Detailed Information Used to Estimate Benefits for Universe of Surface Impoundments

Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring	Capacity (Acre Feet)	Size Class
641	6146SPD-6	SI	Yes	TX	late	347	Large
642	6147SPD-4	SI	Clay	TX	late	265	Large
643	6178Primary Ash Pond	SI	Clay	TX	late	2,700	Large
644	6178Secondary Settling Pond	SI	Clay	TX	late	300	Large
645	6179Management Unit 002	SI	Clay	TX	late	2,293	Large
646	6179Management Unit 009	SI	Clay	TX	late	600	Large
647	6180SPD-2	SI	Clay	TX	late	144	Large
648	6181SPD-1	SI	NA	TX	late	54	Large
649	6181SPD-2	SI	NA	TX	late	50	Large
650	6183SPD-3	SI	Clay	TX	late	216	Large
651	6183SPD-4	SI	Clay	TX	late	104	Large
652	6648EPRI 8	SI	Unknown	TX	late	837	Large
653	7097SPD-1	SI	Yes	TX	late	9	Small
654	7097SPD-2	SI	Yes	TX	late	47	Large
655	7902Auxilliary Surge Pond	SI	NA	TX	late	64	Large
656	7902East Bottom Ash Pond	SI	NA	TX	late	188	Large
657	7902Secondary Bottom Ash Pond	SI	NA	TX	late	12	Small
658	7902West Bottom Ash Pond	SI	NA	TX	late	188	Large
659	3644SPD-1	SI	NA	UT	early	14	Small
660	3644SPD-2	SI	NA	UT	early	3	Small
661	6481Ash Water Recycle	SI	Yes	UT	early	590	Large
662	6481Bottom Ash Basin	SI	Yes	UT	early	3,000	Large
663	6481Evaporation Ponds (6 Ponds)	SI	Yes	UT	early	3,225	Large
664	6481Land Fill Run-Off	SI	Yes	UT	early	30	Large
665	6481Settling Basin	SI	Yes	UT	early	145	Large
666	6481Wastewater Holding Basin	SI	Yes	UT	early	650	Large
667	7790SPD-3	SI	NA	UT	early	11	Small
668	7790SPD-5	SI	NA	UT	early	65	Large
669	7790SPD-6	SI	NA	UT	early	69	Large
670	8069SPD-4	SI	Yes	UT	early	4	Small
671	3775Bottom Ash Pond 1A/1B	SI	NA	VA	early	1,240	Large
672	3776Auxiliary Fly Ash Pond	SI	NA	VA	early	185	Small

Exhibit O-2

Detailed Information Used to Estimate Benefits for Universe of Surface Impoundments

Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring	Capacity (Acre Feet)	Size Class
673	3776Bottom Ash Pond	SI	NA	VA	early	90	Large
674	3796North Ash Pond	SI	NA	VA	early	4,300	Large
675	3796West Ash Pond	SI	NA	VA	early	290	Large
676	3797Lower (Old) Ash Pond	SI	NA	VA	early	740	Large
677	3797Upper (New) Ash Pond	SI	NA	VA	early	10,240	Large
678	3803Bottom Ash/Sedimentation Pond	SI	NA	VA	early	77	Large
679	7213SPD-2	SI	Yes	VA	early	4	Small
680	7213SPD-3	SI	Yes	VA	early	11	Small
681	10771SPD-1	SI	NA	VA	early	9	Small
682	3982Polishing Pond	SI	Unknown	WI	late	3	Small
683	3982Surge Basin	SI	Unknown	WI	late	1	Small
684	4050A Ponds (Two)	SI	Unknown	WI	late	44	Large
685	4050B Pond	SI	Unknown	WI	late	19	Small
686	4050C Pond	SI	Unknown	WI	late	3	Small
687	4050F Pond	SI	Unknown	WI	late	9	Small
688	4050Slag Pond	SI	Unknown	WI	late	10	Small
689	4054Slag Pond	SI	Unknown	WI	late	20	Small
690	4057Final WPDES Pond	SI	Unknown	WI	late	29	Large
691	4057Slag Pond	SI	Unknown	WI	late	29	Large
692	4057WPDES Pond 1	SI	Unknown	WI	late	17	Small
693	4057WPDES Pond 2	SI	Unknown	WI	late	14	Small
694	4072SPD-1	SI	NA	WI	late	2	Small
695	4078SPD-1	SI	NA	WI	late	39	Large
696	4078SPD-2	SI	Clay	WI	late	0	Small
697	4078SPD-3	SI	Clay	WI	late	0	Small
698	4078SPD-4	SI	Clay	WI	late	14	Small
699	4078SPD-5	SI	Clay	WI	late	14	Small
700	4078SPD-6	SI	Clay	WI	late	5	Small
701	8023Polishing Pond	SI	NA	WI	late	5	Small
702	8023Primary Ash Pond	SI	NA	WI	late	72	Large
703	8023Secondary Ash Pond	SI	NA	WI	late	204	Large
704	3935Bottom Ash Complex	SI	NA	WV	late	220	Large

Exhibit O-2

Detailed Information Used to Estimate Benefits for Universe of Surface Impoundments

Count	Unique Name	Unit Type	Liner Type	State	Baseline GW Monitoring	Capacity (Acre Feet)	Size Class
705	3935Fly Ash Pond	SI	NA	WV	late	2,687	Large
706	3936Bottom Ash Complex	SI	Unknown	WV	late	116	Large
707	3938Bottom Ash Pond	SI	NA	WV	late	256	Large
708	3938Unit 5 (Fly Ash Pond)	SI	NA	WV	late	1,965	Large
709	3942SPD-1	SI	Clay	WV	late	10	Small
710	3942SPD-2	SI	Clay	WV	late	10	Small
711	3945SPD-4	SI	NA	WV	late	182	Large
712	3947Boiler Slag Pond	SI	Unknown	WV	late	22	Large
713	3948Bottom Ash Complex	SI	Yes	WV	late	262	Large
714	3948Fly Ash Pond	SI	Unknown	WV	late	13,500	Large
715	6004McElroy's Run Embankment	SI	NA	WV	late	20,000	Large
716	6264Bottom Ash Complex	SI	Clay	WV	late	508	Large
717	10151SPD-3	SI	NA	WV	late	1	Small
718	10151SPD-4	SI	NA	WV	late	15	Small
719	10151SPD-7	SI	NA	WV	late	4	Small
720	10151SPD-8	SI	NA	WV	late	1	Small
721	10151SPD-9	SI	NA	WV	late	0	Small
722	41581A Clear Pond	SI	NA	WY	early	16	Small
723	41581B Ash Pond	SI	Yes	WY	early	112	Large
724	41581B Clear Pond	SI	NA	WY	early	20	Small
725	41584 Clear Pond	SI	NA	WY	early	50	Large
726	41584A Ash Pond	SI	Yes	WY	early	145	Large
727	41584B Ash Pond	SI	Yes	WY	early	145	Large
728	4162FGD Pond #1	SI	Yes	WY	early	1,038	Large
729	4162FGD Pond #2	SI	Yes	WY	early	671	Large
730	4162North Ash Pond	SI	NA	WY	early	3,370	Large
731	4162South Ash Pond	SI	NA	WY	early	4,057	Large
732	6101Wyodak	SI	NA	WY	early	320	Large
733	6204Bottom Ash Ponds 1 & 2 (BAP1 & BAP2)	SI	Yes	WY	early	2,111	Large
734	6204Emergency Holding Pond	SI	Yes	WY	early	916	Large
735	8066FGD Pond #2	SI	NA	WY	early	11,534	Large

APPENDIX P

***“Pre-Rule”* Baseline & *“Post-Rule”* CCR Impoundment Environmental Release Frequency & Volume Probabilities Assumed in the Regulatory Impact Analysis (RIA) for EPA’s 2015 CCR Final Rule**

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Revised: 12 June 2014

Note: EPA has updated the RIA to reflect revised assumptions about failure probabilities and capacity factors. See **Section 9.2.6** in **Chapter 9** of this RIA for a description of the relevant modifications and updates. This appendix has not been updated to reflect the revisions described in **Sections 9.2.6**.

A. Introduction

This appendix presents this RIA's assumptions about the future probabilities of CCR impoundment environmental (a) CCR release events and associated future (b) CCR release volumes for both the "*pre-rule*" baseline scenario (i.e., a hypothetical future scenario without the CCR final rule), and for the "*post-rule*" scenario (i.e., after implementation of the CCR final rule).

The RIA applies these assumptions for purpose of estimating the potential future environmental protection benefits which EPA expects that three of the CCR final rule's pollution control requirements would provide by reducing both the release frequency probability and release volumes:

- (a) Structural integrity: CCR impoundment structural integrity requirements (i.e., impoundment "*factors of safety*" design criteria, and impoundment inspection requirements).
- (b) Location restrictions: CCR impoundment site location standards (i.e., restriction from locating in water tables, floodplains, wetlands, fault areas, seismic zones, and unstable areas such as karst¹ areas).
- (c) Stormwater control: Stormwater run-on/run-off controls for CCR impoundments.

B. Future "*Pre-Rule*" Baseline Assumptions

In early 2009 EPA-ORCR mailed a ten-question survey² to electric utility plants to request descriptive information about CCR impoundments. A total of 240 electric utility companies responded to the survey, providing information on a total of 676 surface impoundments located at those plants. Of the 676 impoundments reported, 20 were other types of impoundments (e.g., coal pile sumps, metal cleaning waste impoundments, wastewater treatment impoundments), not CCR impoundments, reducing the survey count of CCR impoundments to 656.

One question in that survey asked plants to provide brief histories of known spills or unpermitted releases to surface water or to land (not including releases to groundwater) of CCR from impoundments within the last ten years (i.e., 1999 to 2008) from the 2009 date when EPA-ORCR conducted this survey.

Electricity power plants reported in the 2009 survey a total of 52 historical releases from CCR impoundments as summarized in **Exhibit P-6** at the end of this Appendix. Subtracting the three

¹ Karst area = An irregular limestone region with sinks, underground streams, and caverns (source: Merriam Webster's Collegiate Dictionary, 10th edition, 1996).

² Following the December 2008 release of 5 million cubic yards (1.1 billion gallons) of CCR from an impoundment at the Tennessee Valley Authority's Kingston TN coal-fired electricity power plant, EPA took aggressive steps to assess CCR impoundments and other units that manage residuals from coal combustion and that contain free liquids. TVA's Kingston spill of CCR flooded more than 300 acres of land, damaging homes and property. The released CCR flowed into the Emory and Clinch rivers, filling large areas of the rivers and resulting in fish kills. This catastrophic spill prompted EPA to gather more information from electricity power plants managing CCR nationwide. EPA conducted its 2009 mail survey questionnaire under authority of Section 104(e) of the Community Emergency Response, Compensation & Liability Act (CERCLA). Survey responses from power plants are available on EPA-ORCR's website at <http://www.epa.gov/waste/nonhaz/industrial/special/fossil/surveys/index.htm>

non-CCR impoundment cases reported (i.e., coal pile sump and two metal cleaning waste basins) yields 49 historical CCR impoundment release cases reported in the 2009 mail survey. The types of releases reported consisted of:

- Wall breaches: 8% (4 of 49) structural failures of external perimeter embankments.
- Other releases: 92% (45 of 49) remainder cases were other causes of impoundment release events:
 - Wall seepage: 27% (13 of 49)
 - Overtopping: 16% (8 of 49) from severe rainfall or adjacent riparian flood events
 - Miscellaneous release causes: 27% (13 of 49)
 - Sink hole
 - Stack failure
 - Pump failure
 - Hydraulic dredging pipe broke
 - Liner hole
 - Internal dike breach (not perimeter)
 - Seal failure
 - Discharge structure disturbed during maintenance
 - Embankment slough (2 cases)
 - Abandoned decant weir failed
 - Release causes not reported in EPA's 2009 mail survey: 22% (11 of 49) --- this RIA assumes these are proportionally similar to the reported causes.

A sub-total 31 of the total 240 electricity plants which responded to the 2009 survey reported the 49 historical release cases. By defining a historical data "observation" as one-year-per-impoundment over the ten historical years (i.e., 1999 to 2008, plus the two release events reported for 1995 & 1998) of the 2009 survey period, the 49 historical cases represent 6,565 data observations. In relation to this total observation count, it is possible to calculate the "pre-rule" average annual release (failure) probability represented by these 49 cases.

Exhibit P-1 below presents the release probability results according to two impoundment size categories of "*Big*" and "*Small*." "*Big*" is defined according to the three size criteria applicable to the impoundment "factors of safety" design criteria structural integrity requirements of the CCR final rule. Specifically, a *Big* impoundment meets the following criteria:

- Height (impounding elevation) of five feet or more above the upstream toe, and
- Storage volume of 20 acre-feet or more, or
- Height (impounding elevation) of 20 feet or more above the upstream toe.

Impoundments that do not meet these criteria are designated as "*Small*." This distinction is important because the impoundment structural integrity requirements of the CCR final rule do not equally apply to both "*Big*" and to "*Small*" impoundments.

Exhibit P-1 also presents the results of an average "*capacity factor*" calculation for each impoundment size category (Big & Small), calculated as a percentage ratio:

$$\text{Capacity factor} = \frac{(\text{gallons of CCR released})}{(\text{CCR impoundment design capacity gallons})}$$

This factor can only be calculated for the 18 (37%) of the 49 historical release cases which reported gallons released in the 2009 EPA-ORCR survey.

Exhibit P-1 Future “Pre-Rule” Baseline Probabilities of CCR Impoundment Failure Releases Based on Analysis of 49 Historical Failure Events 1995–2008 [1]			
Impoundment type	All CCR Impoundment Sizes	Big	Small
Number of releases	49	43	6
Average annual probability of a release	0.75%	0.97%	0.28%
Average capacity factor	6.28%	4.95%	0.41%
A. Impoundment Type – All Sizes			
Total number of observations	6,565		
Release Type	All Releases [2]	Wall Breach	Other Releases
Number of releases	49	4	45
Average annual probability of a release	0.75%	0.06%	0.69%
Average capacity factor	6.28%	27.42%	2.05%
B. Impoundment Type – Big ((1) at least 5 feet high AND at least 20 acre-feet OR (2) at least 20 feet high independent of volume)			
Total number of observations	4,444		
Release Type	All Releases [2]	Wall Breach	Other Releases
Number of releases	43	4	39
Probability of a release	0.97%	0.09%	0.88%
Average capacity factor	4.95%	27.42%	2.65%
C. Impoundment Type – Small (Does not fit “big” criteria (see above))			
Total number of observations	2,121		
Release Type	All Releases [3]	Wall Breaches	Other Releases
Number of releases	6	Not applicable	6
Probability of a release	0.28%	Not applicable	0.28%
Average capacity factor	0.41%	Not applicable	0.41%
Notes: [1] Results displayed in this Exhibit calculated March 13, 2014 by Abt Associates Inc (Cambridge MA) under a contract work assignment with the EPA Office of Water (James Covington COTR). [2] Number of releases and probability of release are the sum of wall breaches and other releases; capacity factor is weighted average of wall breaches and other releases. [3] For small impoundments, “all releases” only include “other” because wall breaches were not reported for small impoundments in the 2009 survey.			

C. Future “Post-Rule” CCR Impoundment Release Events Assumptions

This section provides an explanation and documentation of the assumptions applied in this RIA for future “post-rule” CCR impoundment release (failure) events; in other words, the assumptions applied in this RIA about the degree to which the CCR impoundment (a) location restrictions, (b) stormwater run-on/run-off controls, and the (c) structural integrity requirements of the CCR final rule may be expected to prevent, and thereby reduce, future CCR impoundment release events. This section separately considers the same two categories of potential future release events (i.e., “wall breaches” and “other releases”) as considered above in the “pre-rule”

baseline section. **Exhibit P-2** below provides a summary of the location restrictions, stormwater run-on/run-off controls, and structural integrity requirements of the CCR final rule.

Exhibit P-2

CCR Final Rule Requirements Which Provide Structural Protection to Impoundments

A. Location Restrictions:

For **all** existing and new CCR surface impoundments and all lateral expansions:

1. Placement above the seasonal water table
2. Not located in wetlands
3. Not located in fault areas
4. Not located in seismic impact zones
5. Not located in geographically unstable areas (e.g., karst zones)

B. Stormwater Run-On/Run-Off Controls:

For **all** existing and new CCR impoundments, and all lateral expansions:

- Must design, construct, and maintain both a run-on and run-off control systems to collect and control peak discharge flows into and from the active portion of impoundments resulting from certain extreme levels of flood events.
- Must be designed, constructed, maintained, and operated to prevent overtopping from normal or abnormal operations, overfilling, wind and wave action, rainfall, and stormwater run-on.

C. Structural Integrity Requirements:

C1. “Factors of Safety” Design Criteria

For **all** existing and new CCR impoundments, and all lateral expansions:

- Not to be located in seismic impact zones, unless can withstand maximum forces

For **existing** “big” surface impoundments only:

1. Must meet static and seismic factors of safety
2. Stable foundations and abutments
3. Adequate slope protection
4. Embankment is mechanically compacted to meet stated specifications
5. Faces of embankments and surrounding areas are vegetated
6. Meet spillway design specifications for certain extreme levels of storm events
7. Structural integrity of underlying hydraulic structures
8. One year after CCR rule owner must provide report showing criteria have been met, and then renew report every 5 years
9. If considered high or significant hazard potential, must provide Emergency Action Plan after 180 days of effective date

For **new** “big” surface impoundments or lateral expansions

- 1 to 7. Same as items 1 to 7 for existing “big” impoundments listed above
8. Develop plan for new or expanded impoundments
9. Complete a report 60 days before commencing constructing outlining how the impoundment will meet the above criteria
10. Complete a report every 5 years certified by a professional engineer, to show it still meets requirements prior to receipt of CCR, those with significant or high hazard potential shall provide an Emergency Action Plan.

B2. Inspection Requirements:

For **all** existing and new CCR impoundments, and all lateral expansions:

- Must be inspected by a qualified person within every 7 days and immediately following unusual events, and complete a report recording the inspection results

For “big” existing and new CCR surface impoundments, and lateral expansions

- Inspect annually to ensure good engineering standards
- Annually review report from previous inspections
- Annually inspect impoundment and appurtenant structures
- Annually inspect underlying hydraulic structures
- After annual inspection, produce a complete report including:
 - changes in geometry of impounding structure
 - location/type of installed instruments and its readings
 - min, max and present depth and elevation of impoundment
 - storage capacity
 - volume of impoundment

For **all** existing and new CCR surface impoundments or lateral expansions:

- When potentially hazardous situation develops, must:
 - Take action to eliminate it
 - Notify officials and potentially affected persons
 - Notify and prepare to evacuate personnel
 - Direct qualified person to monitor at least once every 8 hours
- Prepare a report documenting actions to be taken if a potentially hazardous situation develops

C1. Future “*Post-Rule*” Wall Breach Assumptions

The location restriction standards, stormwater run-on/run-off controls, and impoundment structural integrity requirements of the CCR rule, summarized in **Exhibit P-2** above, are designed to prevent as close to 100% of impoundment wall breach failures as possible. However, no inspection or assessment regime can be expected to eliminate completely the future probability of any wall breach (i.e., external perimeter wall failure). There will always be a risk of failures due to circumstances beyond reasonable control, such as extreme precipitation events, seismic activity, and other natural events that exceed the design criteria for the impoundments. Further, there will likely be some risk of failure, regardless of the stringency of the inspection regime, due to human error and latent defects that may not be detected e.g., unseen defects in an embankment foundation, buried pipes, etc.

Several relevant sources from the literature support the notion that a residual failure risk will exist even after CCR rule implementation:

- In 1996, the International Commission on Large Dams (ICOLD 2001) initiated a major effort to investigate tailings dams and to change construction and operational practices. The effort resulted in a report detailing the causes of several tailings impoundment failures.
- In a follow up study, Chambers & Higman (2011) evaluated the 10-year period from 2002-2011 to assess the success of the new practices. Tailings impoundment failures continued to occur at approximately one per eight months.³
- Other research by NRC (2002) identified the number of structural failures at coal refuse impoundments that occurred after the implementation of the 1975 Mine Safety and Health Administration’s (MSHA) design, inspection, and construction standards – standards that are very similar to the inspection regime developed for this rule. NRC found that there were four structural failures that occurred after these requirements were in place.⁴

The three research studies summarized above strongly suggest there will remain a non-zero (i.e., greater than zero) risk of CCR impoundment wall breaches following CCR rule implementation. While research has demonstrated that wall breach risk will remain following implementation of structural integrity requirements, only one existing study provided data to inform quantification of this risk.⁵

- Upper estimate: Rico et al. (2008)⁶ evaluated historical mine tailings dam failures. These data are appropriate to the purpose of this Appendix because (a) mine tailings dams are

³ Source: Page 4 of “Long Term Risks of Tailings Dam Failure,” David M. Chambers & Bretwood Higman, October 2011, available at: http://ofmpub.epa.gov/eims/eimscomm.getfile?p_download_id=513583

⁴ National Research Council, “Coal Waste Impoundments: Risks, Responses, and Alternatives,” National Academy Press, 2002, available at: http://www.nap.edu/catalog.php?record_id=10212

⁵ The data from Chambers and Higman (2011) and from NRC (2002) are not in a form to allow for calculation of a residual failure rate.

⁶ M. Rico, G. Benito, A.R. Salquerio, A. Diez-Herrero, H.G. Pereira, “Reported Tailings Dam Failures: A Review of the European Incidents in the Worldwide Context,” *Journal of Hazardous Materials*, Vol. 152, 2008, pp. 846-852; <http://www.elsevier.com/locate/jhazmat>

analogous to CCR impoundments, (b) the Rico study examined and categorized failures at numerous tailings dams, and (c) the study was published in peer-reviewed literature. The study found that of 147 failures worldwide:

- 25% were due to extreme precipitation events.
- 14% were due to seismic events.
- 10% were due to poor management and lack of safety inspections.
- 6% were due to poor dam placement and construction.

One interpretation of these data is that 39% of the failures occurred from extreme natural events and up to 10% were due to human error, meaning that structural integrity requirements could prevent up to 51% of failures. Using the results from this study, and relative to the baseline wall breach failure rate of 0.09% (as estimated in Section B above), produces a post-rule wall breach failure rate of **0.044%** per year per impoundment. This result probably represents an upper-bound result in comparison to the alternative result formulated below based on the 2009 EPA-ORCR historical data.

An alternative approach to estimating post-rule wall breach failure risk is to examine the data set available from the 2009 EPA-ORCR survey (cited in Section A above) and calculate a post-rule residual failure rate based on the observed wall breach failures from the EPA survey.

- Lower-estimate: The 2009 EPA-ORCR historical (1999-2008) CCR impoundment release data suggest that at least one of the four observed wall breaches was due to human error, and would likely not have been prevented by the rule requirements.⁷ Based on the limited data available, it is plausible to assume that the structural integrity requirements in the CCR rule would have prevented the other three failures, suggesting the CCR rule requirements could be 75% effective. Applying this to the baseline wall breach failure rate of 0.09% results in a residual post-rule failure rate of **0.023%** per year per impoundment (i.e., 25% x 0.09%).

However, this post-rule rate only accounts for failure from human error, and assumes that there would be no failures from extreme natural events or latent defects, which is not supported by research nor by the data regarding mine tailings dam failures discussed above. Moreover, the 2009 EPA-ORCR survey data are limited to failures observed over a relatively brief 10-year period, during which only four wall breach failures occurred. Failures actually observed over a longer period could show a higher or lower percentage of failures attributable to unpreventable causes. However, this method has the advantage of being based on actual historical observations of CCR impoundment wall breach failures. Because of the uncertainty of relying on four data points to project future events, this case likely represents a lower-bound of the residual failure rate.

⁷ According to the 2009 EPA-ORCR survey, the failure at the Indianapolis Power and Light Co. in 2008 was attributed to "...the repair designed by Fuller, Mossbarger, Scott, and May Engineers (FMSM) in that they overestimated the shear strength of the fly ash. BTSQUARED concluded the redesigned embankment cross-section by FMSM was inadequate to support the loading conditions in Pond D and Pond E." See [cite survey] available online at <http://www.epa.gov/osw/nonhaz/industrial/special/fossil/surveys2/ipl-ligheagle-final.pdf>.

Given the upper-bound and lower-bound limitations of the two alternative data approaches presented above, the RIA applies the **0.034%** average value based on the two bounding results above (i.e., $(0.044\% + 0.023\%) / 2$). The percentage reduction in future impoundment wall breaches implied by this 0.034% residual wall breach probability represents a **-62% reduction** in the 0.09% baseline wall breach probability calculated as follows: $[(0.09\% \text{ baseline rate}) - (0.034\% \text{ residual rate})] / (0.09\% \text{ baseline rate}) = -62\%$.

- **Reality Check of the Future “Post-Rule” Wall Breach Probability Assumption**

The following three comparisons provide a “reality check” on the reasonableness of this RIA’s 0.034% post-rule CCR impoundment wall breach probability assumption.

- Reality check #1 of 3: Human Error Release Cases in the 2009 EPA-ORCR 49 Historical CCR Impoundment Failure Cases

As a 1st reality check which only accounts for un-controllable “human error” CCR impoundment release cases, it appears that only two of the 49 CCR impoundment release events in the 2009 EPA-ORCR data involved unforeseen human errors which might not be prevented either by location standards, stormwater controls, or structural integrity requirements of the CCR final rule (i.e., hydraulic dredging pipe broke, and discharge structure disturbed during maintenance). In relation to the 6,565 data observations associated with the 49 historical cases, the average annual probability of such human error causation is **0.030%** per year (i.e., $(2 \text{ human error “other release” events}) / (6,565 \text{ observations}) \times 100\% = 0.030\%$). This human error probability value is numerically relatively close to (-12% less than) the 0.034% numerical value assigned in this RIA to the post-rule wall breach probability value assumed in this RIA.

- Reality check #2 of 3: Historical Data on Coal Mine Slurry Impoundment Failures

In 1975 the Mine Safety & Health Administration (MSHA) of the US Department of Labor published its first manual to assist in the design, inspection, and construction of coal refuse disposal facilities. According to MSHA, hundreds of then existing and planned coal refuse disposal facilities were upgraded to new and safer standards, and for coal mine slurry impoundments, significant emphasis was placed on dam safety (i.e., impoundment perimeter embankment safety).⁸ As of 2001, MSHA oversees 713 active coal mine slurry impoundments.

However, while MSHA’s engineering and design measures were implemented by coal mine slurry impoundments to minimize the potential for failure of coal refuse disposal facilities, wall breaches continued to occur at a residual (post-manual) average annual rate of about 0.02% per year. This annual frequency is derived here based on the four coal mine refuse impoundment wall breach events⁹ which occurred in the 25-year “post-manual” period 1976 to 2000 as

⁸ Source: Page 2-11 of “Engineering and Design Manual: Coal Refuse Disposal Facilities,” Mine Safety & Health Administration, 2nd edition, May 2009 at <http://www.msha.gov/Impoundments/DesignManual/ImpoundmentDesignManual.asp>

⁹ The four coal mine slurry impoundment wall breach events are (source: the four wall breach events identified by the National Research Council’s 2002 study are summarized on pages 2-13 and 2-14 of MSHA’s May 2009 2nd edition manual):

1. August 14, 1977: Island Creek Coal Company, WV: Heavy rainfall caused water level in an impoundment to rise, eroding the perimeter embankment.
2. December 18, 1981, Eastover Mining Company, KY: An impoundment 192 feet high reached 90% of its planned capacity and a stream flowed into the impoundment (plus other factors) causing perimeter embankment to fail.

reported in a 2002 study by the National Research Council¹⁰ (i.e., (4 wall breaches) / (25-year period) / (713 MSHA regulated impoundments) = **0.02%** per year). This 0.02% average annual residual frequency is -41% less than the 0.034% value applied in this RIA, but is relatively close to (-13% lower than) the 0.023% lower bound on which the 0.034% is in part based.

- Reality check #3 of 3: 2002 to 2011 Historical Data on 123 Mine Tailings Impoundment Failures

A 2011 study by Chambers & Higman indicated that in the ten year period 2002 to 2011 after the International Commission on Large Dams (ICOLD) (a) initiated in 1996 a major effort to investigate tailings dams and change construction and operational practices, as well as (b) in 2001 published several reports which investigated the causes of worldwide tailings dam failures, *“the failure rate of tailings dams has remained roughly one failure every 8 months (i.e., three failures every two years).”*¹¹ This “post-ICOLD” residual failure rate represents an average annual residual failure probability of **0.04%**, calculated as follows: [(3 failures) / (2 years)] / (3,500 worldwide tailings dams) = 0.04%. This rate is relatively close to (+18% higher than) the 0.034% value assumed in this RIA, but is very close to (-9% less than) the 0.044% upper bound on which the 0.034% is in part based.

C2. Future “Post-Rule” Assumptions for “Other Release” Events (Non-Wall Breaches)

As summarized in the first section of this Appendix, 92% (45) of the types (causes) of the 49 historical cases were associated with “other types” (causes) of impoundment releases, not wall breaches. Based on 33 of the 45 “other releases” which provided causation, these “other releases” consisted of three sub-categories:

- (a) Wall seepage: (13 of 32 = 41%).
- (b) Overtopping: (8 of 32 = 25%) from severe rainfall or adjacent riparian flood events.
- (c) Miscellaneous causes: (11 of 32 = 34%) consisting of sink hole, stack failure, pump failure, hydraulic dredging pipe broke, liner hole, internal dike breach (not perimeter), seal failure, discharge structure disturbed during maintenance, embankment slough (2 cases), and abandoned decant weir failed.

- **Post-Rule “Other” Releases From Active CCR Impoundments**

In relation to the known causes of 32 of the 45 “other release” events --- and simply assuming that the pattern of known causes represents the pattern (causation) of the other 13 “other release” events without causation information in the 2009 EPA-ORCR database --- **Exhibit P-3** below

-
3. April 8, 1987: Peabody Coal Company, WV: Heavy snowfall followed by rapid outdoor temperature increases contributed to a 55-foot high impoundment perimeter embankment to fail.
 4. January 28, 1994: Consolidation Coal Company, WV: “Heavy rain and melting snow accumulated in an impoundment causing a five foot perimeter embankment to fail.

¹⁰ National Research Council, “Coal Waste Impoundments: Risks, Responses, and Alternatives,” National Academy Press, 2002, available at: http://www.nap.edu/catalog.php?record_id=10212

¹¹ Source: Page 4 of “Long Term Risks of Tailings Dam Failure,” David M. Chambers & Bretwood Higman, October 2011, available at: http://ofmpub.epa.gov/eims/eimscomm.getfile?p_download_id=513583

presents this RIA’s post-rule assumptions for “other release” frequency probabilities and associated release volume “capacity factors” for active CCR impoundments.

Exhibit P-3 Assumptions for Post-Rule “Other Release” Events from Active CCR Impoundments				
Type of “Other Release” Events	Big CCR impoundments		Small CCR impoundments	
	Release probability	Release volume capacity factor	Release probability	Release volume capacity factor
A. Wall seepage (13 of 32 other events w/cause data = 41%)	<u>Assumption:</u> <i>“Factors of safety”</i> design criteria of CCR final rule expected to reduce all events other than (a) two human error events (C4 & C8) and (b) two events related to not easily visible components of impoundments (C5 & C10). <u>Result:</u> Would reduce the 32 baseline cases to four cases, which represents an -88% reduction in the pre-rule rate. -88% reduction of the 0.88% pre-rule rate = 0.11% post-rule probability.	<u>Assumption:</u> Mean time interval between pre-rule inspections = 21 weeks. CCR rule’s weekly inspection requirement is 95% more frequent (1/21) which implies 95% reduction in capacity factor from earlier detection. <u>Result:</u> -95% reduction of 2.65% pre-rule capacity factor = 0.13% post-rule capacity factor.	<u>Assumption:</u> Small ponds are not subject to <i>“factors of safety”</i> design criteria under the CCR final rule. However, small ponds are subject to stormwater run-on/run-off controls which this RIA assumes would reduce the 8 baseline overtopping cases = -25% reduction (8/32 = -25%) <u>Result:</u> -25% reduction of the 0.28% pre-rule probability = 0.21% post-rule probability.	<u>Assumption:</u> Mean time interval between pre-rule inspections = 21 weeks. CCR rule’s weekly inspection requirement is 95% more frequent (1/21) which implies 95% reduction in capacity factor from earlier detection. <u>Result:</u> -95% reduction of 0.41% pre-rule capacity factor = 0.02% post-rule capacity factor.
B. Overtopping -- severe rainfall or adjacent riparian flooding (8 of 32 events = 25%)				
C. Miscellaneous “other” release causes (11 of 32 events = 34%): C1. Sink hole C2. Stack failure C3. Pump failure C4. Hydraulic dredging pipe broke C5. Liner hole C6. Internal dike breach (not perimeter) C7. Seal failure C8. Discharge structure disturbed during maintenance C9. Embankment slough (2 cases) C10. Abandoned decant weir failed				

- **Post-Rule “Other Releases” From In-Active CCR impoundments**

For purpose of this RIA, there are two distinct connotations of “in-active” CCR impoundments for both big and small impoundment categories:

1. Pre-rule (baseline) in-active: CCR impoundments which no longer receive CCR by the effective date of the CCR final rule. This RIA assumes that this category of in-active impoundments under the CCR final rule are likely to de-water and breach as a lower-cost-of-compliance, compared to compliance with the final rule’s requirements for active impoundments (for in-active ponds which do not de-water and breach).
2. Post-rule dry conversion in-active: CCR impoundments which are currently active (pre-rule) but which the regulatory cost estimation of this RIA indicates are likely to cease receiving CCR (post-rule) and close, because for some utility plants this RIA indicates

that conversion to dry CCR handling is likely their lower compliance cost option, compared to the post-rule cost of continued use of their CCR impoundments.

For both types of “in-active” impoundments, this RIA assumes the future probability of “Other” release events drops to zero, which renders the capacity factor moot for in-active impoundments.

Exhibit P-4 below presents a diagram of the pre-rule future baseline CCR impoundment release probabilities, and **Exhibit 5** below presents a diagram of the post-rule future CCR impoundment release probabilities assumed in this RIA.

Exhibit P-4

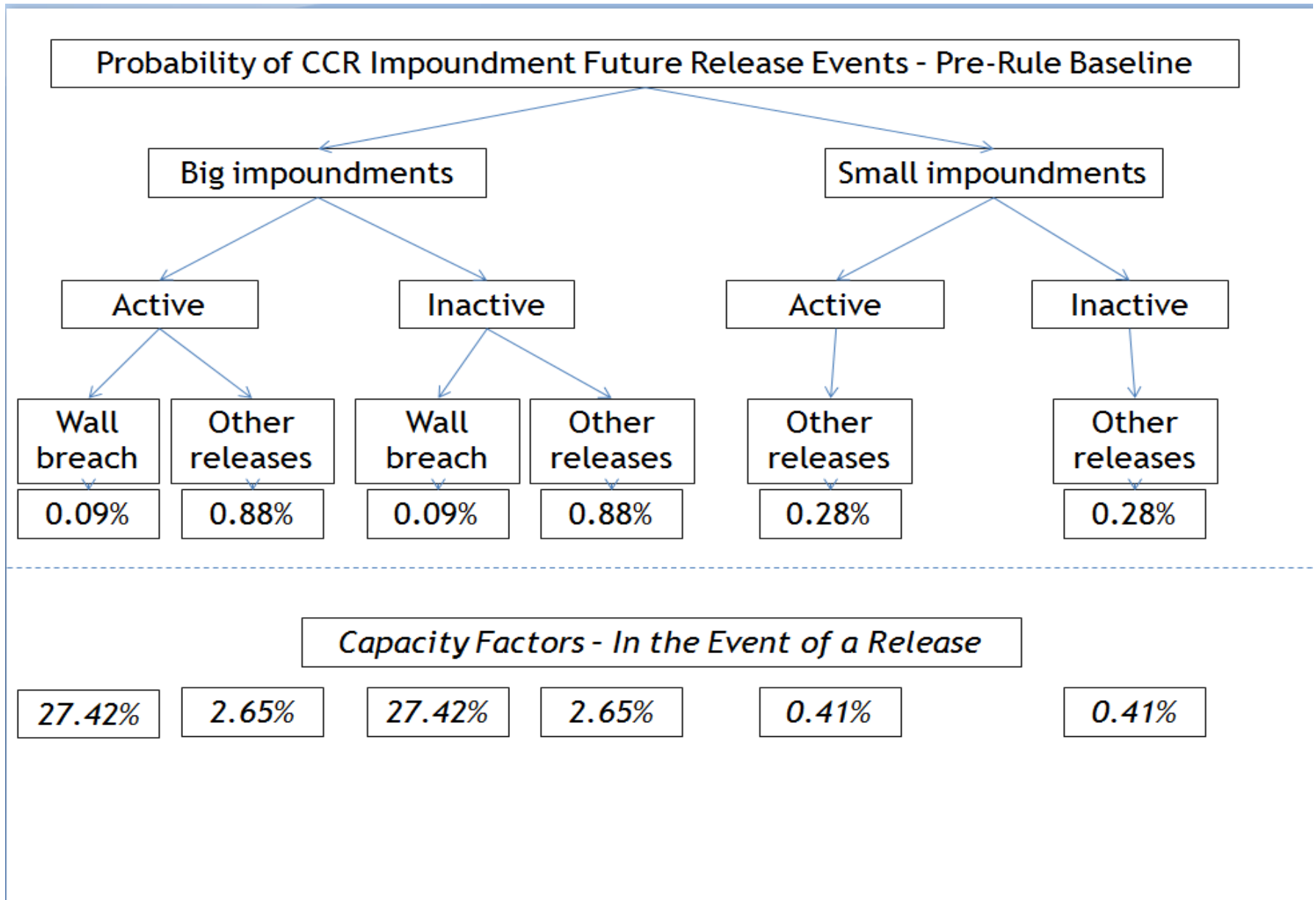
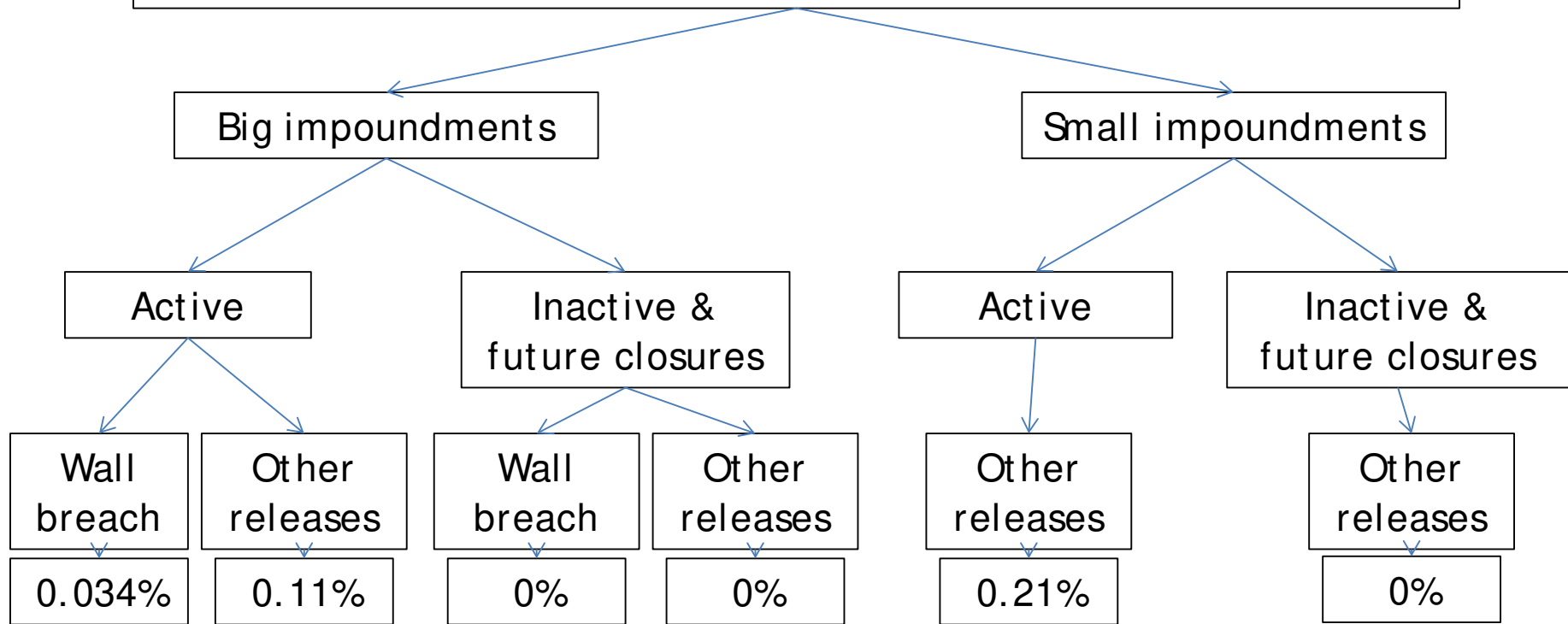


Exhibit P-5

Probability of CCR Impoundment Future Release Events – Post Rule



Capacity Factors – In the Event of a Release

27.42%	0.13%	Not applicable	Not applicable	0.02%	Not applicable

Exhibit P-6 Summary of 52 Historical CCR Impoundment Release Events (1995-2008) Reported to EPA in 2009 by Electric Utility Plants												
A	B	C	D	E	F	G	H	I	J	K	L (K/I)	M
Row	Company Name	Electric Power Plant Name	Impoundment Name	State	Impoundment Height (feet)	Impoundment Storage Capacity (acre-feet)	Impoundment Size Category*	Impoundment Storage Capacity (gallons)	Type of Historical Release	Gallons Released	Release Volume as % of Capacity	Release Year
1	Allete Inc	Clay Boswell Power Station	Coal Pile Sump	MN	20	1	Big	325,851	Overtopping	Unknown	Unknown	2008
2	Ameren Energy Generating Co	Meredosia Power Station	Fly Ash Pond	IL	24	700	Big	228,096,000	Unknown	500	0.0002%	2006
3	American Electric Power	Cardinal Operating Co - Cardinal Power Station	Fly Ash Reservoir 2	OH	237	11,350	Big	3,698,413,719	Seepage	Unknown	Unknown	2004
4	Basin Electric Power Coop	Leland Olds Power Station	Settling Pond #3	ND	18	12	Small	3,910,217	Other	Unknown	Unknown	2000
5	City of Springfield	Lakeside	Lakeside Ash Pond	IL	20	744	Big	242,433,463	Seepage	Unknown	Unknown	1999
6	Dominion	Chesterfield Power Station	Lower (Old) Ash Pond	VA	19	740	Big	241,130,057	Unknown	Unknown	Unknown	2005
7	Duke Energy Corp	Cliffside Power Station	Retired Unit 1-4 Basin	NC	38		Big	0	Overtopping	Unknown	Unknown	2005
8	Duke Energy Corp	Walter C. Beckjord Power Station	Ash Pond C	OH	50	1,400	Big	456,192,001	Seepage	Unknown	Unknown	1999
9	East Kentucky Power Coop Inc	Dale Power Station	Dale Ash Pond #4	KY	26	143	Big	46,596,754	Seepage	Unknown	Unknown	2008
10	First Energy Generation Corp	Bruce Mansfield Power Station	Little Blue Run Dam	PA	400	84,300	Big	27,469,275,465	Seepage	Unknown	Unknown	
11	Georgia Power Co	Bowen Power Station	Ash Pond	GA	45	3,676	Big	1,197,829,853	Other	Unknown	Unknown	2002
12	Georgia Power Co	Bowen Power Station	Ash Pond	GA	45	3,676	Big	1,197,829,853	Other	Unknown	Unknown	2008
13	Georgia Power Co	Harllee Branch Power Station	C	GA	83	1,050	Big	342,144,000	Unknown	35,000	0.0102%	2000
14	Northern Indiana Pub Serv Co	R. M. Schahfer Power Station	Metal Cleaning Waste Basin	IN	4	48	Small	15,640,869	Other	Unknown	Unknown	2009
15	Northern Indiana Pub Serv Co	R. M. Schahfer Power Station	Metal Cleaning Waste Basin	IN	4	48	Small	15,640,869	Unknown	Unknown	Unknown	1998
16	Northern States Power Co	Sherburne County Power Station	Pond No. 2	MN	57	6,198	Big	2,019,627,157	Unknown	600	0.00003%	2007
17	Northern States Power Co	Sherburne County Power Station	Bottom Ash Pond	MN	41	620	Big	202,027,886	Other	8,000	0.004%	2008
18	PacifiCorp	Dave Johnston Power Station	Blowdown Canal	WY	0	3	Small	977,554	Overtopping	14,400	1.47%	2009
19	PacifiCorp	Jim Bridger Power Station	FGD Pond #1	WY	33	1,340	Big	436,640,915	Seepage	Unknown	Unknown	
20	PacifiCorp	Jim Bridger Power Station	FGD Pond #2	WY	42	11,534	Big	3,758,370,382	Seepage	10,000	0.00027%	
21	PacifiCorp	Naughton Power Station	FGD Pond #2	WY	25	671	Big	218,646,309	Seepage	Unknown	Unknown	2006
22	PacifiCorp	Naughton Power Station	North Ash Pond	WY	56	3,370	Big	1,098,119,316	Unknown	9,249,802	0.84%	
23	PPL Generation, LLC	PPL Martins Creek Power Station	Ash Basin 4	PA	43	1,085	Big	353,548,800	Unknown	100,000,000	28.28%	2005
24	PPL Generation, LLC	PPL Montour Power	Ash Basin No. 1	PA	40	5,070	Big	1,652,066,745	Seepage	Unknown	Unknown	2007

Exhibit P-6 Summary of 52 Historical CCR Impoundment Release Events (1995-2008) Reported to EPA in 2009 by Electric Utility Plants												
A	B	C	D	E	F	G	H	I	J	K	L (K/I)	M
Row	Company Name	Electric Power Plant Name	Impoundment Name	State	Impoundment Height (feet)	Impoundment Storage Capacity (acre-feet)	Impoundment Size Category*	Impoundment Storage Capacity (gallons)	Type of Historical Release	Gallons Released	Release Volume as % of Capacity	Release Year
		Station										
25	PPL Generation, LLC	PPL Montour Power Station	Detention Basin	PA	8	53	Big	17,270,126	Seepage	Unknown	Unknown	2004
26	PPL Montana LLC	Colstrip Steam Electric Station	Units 1 & 2 A Pond	MT	25	245	Big	79,833,600	Unknown	2,700	0.00338%	2003
27	PPL Montana LLC	Colstrip Steam Electric Station	Units 1 & 2 Stage Evaporation Ponds (STEP)	MT	88	4,370	Big	1,423,970,745	Unknown	100	0.00001%	1995
28	PPL Montana LLC	Colstrip Steam Electric Station	Units 1 & 2 Stage Evaporation Ponds (STEP)	MT	88	4,370	Big	1,423,970,745	Unknown	50	0.000004%	2000
29	PPL Montana LLC	Colstrip Steam Electric Station	Units 1 & 2 Stage Evaporation Ponds (STEP)	MT	88	4,370	Big	1,423,970,745	Other	2,000	0.00014%	2006
30	PPL Montana LLC	Colstrip Steam Electric Station	Units 3 & 4 Effluent Holding Pond (EHP)	MT	138	17,000	Big	5,539,474,293	Seepage	Unknown	Unknown	1999
31	PPL Montana LLC	Colstrip Steam Electric Station	Units 3 & 4 Effluent Holding Pond (EHP)	MT	138	17,000	Big	5,539,474,293	Seepage	Unknown	Unknown	2004
32	PPL Montana LLC	Colstrip Steam Electric Station	Units 3 & 4 Effluent Holding Pond (EHP)	MT	138	17,000	Big	5,539,474,293	Seepage	Unknown	Unknown	2005
33	Progress Energy Carolinas Inc	Roxboro Power Station	FGD Flush Pond	NC	38	53	Big	17,270,126	Wall breach	Unknown	Unknown	2008
34	Progress Energy Carolinas Inc	W. H. Weatherspoon Power Station	1979 Pond	NC	28	1,375	Big	448,045,715	Other	Unknown	Unknown	2001
35	Santee Cooper (South Carolina Pub Serv Auth)	Winyah Power Station	Unit 3 & 4 Slurry Pond	SC	30	1,700	Big	553,947,429	Other	Unknown	Unknown	2008
36	Tennessee Valley Authority	Johnsonville Power Station	Ash Disposal Area 2	TN	30	2,702	Big	880,450,561	Other	Unknown	Unknown	2004
37	Tennessee Valley Authority	Kingston Power Station	Main Ash Pond	TN	50	8,907	Big	2,902,358,678	Other	Unknown	Unknown	2003
38	Tennessee Valley Authority	Kingston Power Station	Main Ash Pond	TN	50	8,907	Big	2,902,358,678	Other	Unknown	Unknown	2006
39	Tennessee Valley Authority	Kingston Power Station	Main Ash Pond	TN	50	8,907	Big	2,902,358,678	Wall breach	1,100,000,000	37.90%	2008
40	Tennessee Valley Authority	Widows Creek Power Station	Ash Pond	AL	115	11,709	Big	3,815,394,382	Unknown	Unknown	Unknown	2008
41	Tennessee Valley Authority	Widows Creek Power Station	Ash Pond	AL	115	11,709	Big	3,815,394,382	Overtopping	Unknown	Unknown	2004
42	Tennessee Valley Authority	Widows Creek Power Station	Gypsum Stack (Wet Stacking Area)	AL	150	10,961	Big	3,571,657,513	Other	Unknown	Unknown	2009
43	Indianapolis Power & Light Co	Eagle Valley Generating Station	D Pond and E Pond	IN	38	415	Big	135,228,343	Wall breach	30,000,000	22.18%	2008

Exhibit P-6 Summary of 52 Historical CCR Impoundment Release Events (1995-2008) Reported to EPA in 2009 by Electric Utility Plants												
A	B	C	D	E	F	G	H	I	J	K	L (K/I)	M
Row	Company Name	Electric Power Plant Name	Impoundment Name	State	Impoundment Height (feet)	Impoundment Storage Capacity (acre-feet)	Impoundment Size Category*	Impoundment Storage Capacity (gallons)	Type of Historical Release	Gallons Released	Release Volume as % of Capacity	Release Year
44	Indianapolis Power & Light Co	Eagle Valley Generating Station	D Pond and E Pond	IN	28	415	Big	135,228,343	Wall breach	30,000,000	22.18%	2007
45	NRG Texas Power, LLC	Limestone Electric Generating Station	Bottom Ash Cooling Pond	TX	0	50	Small	16,292,571	Overtopping	500	0.0031%	2000
46	Kansas City Power & Light Co	LaCygne Generating Station	Scrubber Sludge Ponds	KS	45	9,298	Big	3,029,766,587	Overtopping	Unknown	Unknown	2007
47	Kansas City Power & Light Co	LaCygne Generating Station	Scrubber Sludge Ponds	KS	45	9,298	Big	3,029,766,587	Overtopping	Unknown	Unknown	2007
48	Kansas City Power & Light Co	LaCygne Generating Station	Scrubber Sludge Ponds	KS	45	9,298	Big	3,029,766,587	Overtopping	Unknown	Unknown	2009
49	MidAmerican Energy Co	Riverside Generating Station	South Surface Impoundment	IA	15	140	Big	45,619,200	Overtopping	Unknown	Unknown	2002
50	Alliant Energy	Interstate Power & Light Co - M.L. Kapp Generating Station	Emergency Ash Secondary Settling Pond	IA	10	2	Small	651,703	Other	Unknown	Unknown	2009
51	Xcel Energy	PSCo Comanche Station	Polishing Pond (#4)	CO	0	12	Small	3,910,217	Other	2,500	0.06%	2007
52	Xcel Energy	PSCo Valmont Station	West Ash Settling Pond	CO	0	16	Small	5,213,623	Unknown	4,204	0.08%	2008
Notes: Column H: "Big" = • If height (impounding elevation) of five feet or more above the upstream toe, and • If storage volume of 20 acre-feet ore more, or • If height (impounding elevation) of 20 feet ore more above the upstream toe. Column I: Estimated by EPA-ORCR by multiplying the survey reported acre-feet capacity data (Column G) by the conversion factor = 325,851.4 gallons per acre-foot. Column J: Type of historical release as assigned by EPA-ORCR based on the brief information supplied in electric plant responses to question 10 of the 2009 mail survey.												

APPENDIX Q

Research on Cleanup Costs for Coal Ash Impoundment Releases (WA 0-05, Task 9, version 4)

DRAFT

Memorandum

Environment and Resources



Date March 13, 2014

To James Covington, EPA/OW/EAD

From Emily Giovanni and Isabelle Morin

Subject Research on Cleanup Costs for Coal Ash Impoundment Releases (WA 0-05, Task 9, version 4)

This memo summarizes the results of a literature search for additional data points on cleanup costs from historical impoundment failures to supplement four incidents for which EPA has cleanup costs (see Section 1).

We reviewed data available on the four impoundment failures for which EPA already had cleanup cost to see if more recent or better sources change the values EPA had used previously (see Section 2).

Research of additional data points (see Section 3) included looking at local news sources in the areas surrounding documented spills, dam assessment reports, company financial reports (i.e. 10-K and 10-Q filings), EPA On-Scene Coordinator Pollution Reports (POLREPs), and general Google searches using incident keywords. We looked for information on cleanup costs for releases where the CCR quantity released was known and greater than 1,000 gallons (based on ORCR survey responses). We expect that cost information is unlikely to be available for smaller releases. We also reviewed websites that aggregate data on CCR releases to identify additional (more recent) releases not included in responses to the ORCR survey. The research identified one more incident with documented cleanup costs.

We updated all cost estimates to 2013\$ using the Engineering News Record Construction Cost Index (unless otherwise indicated).

The five incidents have average cleanup costs of **\$1.35 per gallon spilled** (see Section 4).

1 Existing Data Points

- The Massey Coal slurry spill involved the collapse of a 2,000 acre-foot (651.7 million gallon) surface impoundment on top of an idled underground mine, causing 250 million gallons of slurry to spill into two nearby streams. The cleanup costs of this spill were approximately \$71 million (Pincock, et al., 2001; Geotimes, 2003), or approximately ***\$0.28 per gallon spilled***.
- The Martins Creek spill involved the discharge of 100 million gallons of slurry over the course of 3 days, resulting from the failure of a wooden stop log. Cleanup costs were approximately \$47 million (Nixon, 2006; Barker, 2009; Dewberry and Davis, 2009), or ***\$0.47 per gallon spilled***.
- The TVA Kingston spill involved the release of approximately 1.1 billion gallons of slurry. The cleanup costs were approximately \$1.38 billion (TVA, 2010; 2011), or ***\$1.25 per gallon spilled***.

- The TVA Widows Creek spill involved the release of 6.1 million gallons of gypsum, water, and fly ash. Cleanup costs were approximately \$10 million (TVA, 2009), or ***\$1.64 per gallon spilled***.

2 Revisions to Existing Data Points

Of the four existing data points, two (Kingston and Widows Creek) have costs that are well documented in company annual financial reports. The costs associated with the Massey Energy and Martins Creek spills were based on references in local news reports and an engineering firm newsletter. We therefore looked for additional documentation of the costs associated with these two spills in order to revise or support the costs used.

2.1 Massey

EPA previously assumed that the Massey spill was 250 million gallons and cost \$46 million (not updated) based on a news article (Geotimes, 2003) and an engineering firm newsletter (Pincock, et al., 2001). After updating to 2013\$ (for total costs of \$71 million), this equates to a unit cost of \$0.28 per gallon spilled. However, the Massey Energy 2002 annual financial report (10-K; Massey Energy, 2002) states clearly that the spill was 230 million gallons and that Massey incurred a total of \$58.3 million of cleanup costs in connection with the spill; of this total, \$52.2 million was covered or reimbursed by insurance companies.

After revising the spill size to 230 million gallons and the total cleanup cost to \$58.3 million and updating the costs to 2013\$ (for a total cost of \$89 million), the unit cost for this spill is ***\$0.39 per gallon spilled***.

2.2 Martins Creek

EPA previously assumed that this spill was 100 million gallons based on accounts in news articles (Nixon, 2006; Barker, 2009) and the facility's dam assessment report (Dewberry and Davis, 2009). The two news articles provided different estimates of the cleanup costs associated with the spill: Barker (2009) stated that PPL spent \$37 million, while Nixon (2006) stated that cleanup and repairs were estimated to be \$48 million. In the 2012 CCR Rule RIA, EPA used cleanup costs of \$37 million. This equates to a unit cost of \$0.47 per gallon spilled (after updating to 2013\$ for a total cost of \$47 million).

However, the 2006 PPL Corporation annual report (PPL Corporation, 2006) states that the "best estimate of the cost of the remediation effort" is \$48 million. The same report indicates that the \$37 million estimate cited in the news articles is *not* the cleanup cost, but rather represents the loss to the company after insurance claim settlements.

After updating the revised costs to 2013\$ (for a total cost of \$62 million), the unit cost of this spill is ***\$0.62 per gallon spilled***.

3 Additional Releases

Several additional releases have been documented in the survey data provided by ORCR, dam assessment reports, EPA On-Scene Coordinator pollution reports (POLREPs), and local news sources. Of these, cleanup costs are publicly available for only one: Oak Creek in Wisconsin. Additional information on this spill (and others) is provided in this section.

3.1 Oak Creek

In October 2011, a bluff collapsed near an ongoing construction project at the Wisconsin Energy Oak Creek power plant, releasing 22,720 cubic yards (or 4.6 million gallons) of coal ash into Lake Michigan. The collapse also carried debris including vehicles, heavy machinery, a filter press, a frac tank, four conex boxes filled with unknown amounts of miscellaneous equipment down the bluff and into Lake Michigan (Wisconsin Department of Justice (DOJ), 2013a). Wisconsin Energy's immediate response to the spill included the placement of 1,500 feet of containment berms and booms and a geotechnical analysis of the stability of the bluff (Wisconsin DOJ, 2013a; Jones and Behm, 2011). Additional response actions included excavation and removal of the material that had been spilled, with cleanup being complete by the end of November 2011 (Wisconsin DOJ, 2013a).

In July 2013, the Wisconsin DOJ reached a settlement with Wisconsin Energy over violations discovered in the aftermath of the collapse. Wisconsin Energy agreed to pay \$100,000 to the state of Wisconsin, including (Wisconsin DOJ, 2013b):

- \$53,400 to reimburse the state for response costs,
- \$3,000 for prosecution costs, and
- Forfeitures, costs, and surcharges of \$43,600.

According to the U.S. EPA On-Scene Coordinator (U.S. EPA OSC, 2012), Wisconsin Energy reported spending \$12.1 million on cleanup and restoration. After updating to 2013\$ (for a total of \$13 million), unit costs are **\$2.83 per gallon spilled**.

3.2 Dan River

In early February 2014, a coal ash release occurred at the Dan River power plant operated by Duke Energy in North Carolina. The release of 27 million gallons of ash and ash pond water was caused by a failed slip-joint concrete and corrugated steel storm sewer line running under the ash pond (U.S. EPA OSC, 2014). Cleanup will involve removing the ash using shovels or possibly a passive collection system in the river. Duke Energy has stated that company investors and insurers will pay for the cleanup rather than customers (Ford, 2014).

As cleanup is ongoing, no cost estimates are available.

3.3 Eagle Valley

In February 2007, impoundments at the Eagle Valley power plant operated by Indianapolis Power and Light (IPL) released 30 million gallons of coal ash. The spill resulted from the failure of a dike separating Pond D and Pond E, causing an overtopping of Pond E. In the aftermath of the spill, IPL hired an engineering firm to assess and repair the dike system at a cost of \$45,500 (IBJ, 2010). However, in January 2008, the same dike collapsed in the same location, again releasing 30 million gallons. In both cases, the remedial action included the repair of the levee but with no recovery of the released materials (IPL, 2009; Young, 2010). After the two spills, the Indiana Department of Environmental Management charged IPL \$23,800 in civil penalties, while IPL sued the engineering firm for compensatory damages as well as the costs and fines associated with the second spill (IBJ, 2010).

As none of the spilled material was recovered, this incident does not represent a potential data point.

3.4 Captina Creek

There have been multiple spills from coal mine slurry impoundments owned by Murray Energy into Captina Creek in Ohio. In 2008, a pipeline leak allowed 30,000 gallons of coal ash sludge to be released (Coal Age, 2010). As a result of this spill, several miles of the creek were discolored. For several days after the spill, contractors hired by Murray Energy vacuumed the visible ash from the creek, and the Ohio EPA and DNR had additional cleanup and restoration responsibilities. Murray Energy paid a \$50,000 fine for the incident (Coal Age, 2010).

In 2010, there was another pipeline rupture, releasing an unknown amount of slurry to Captina Creek, killing more than 4,300 animals including 3,500 fish (Coal Age, 2010). Additionally, the creek is the last known breeding ground of the endangered Eastern Hellbender Salamander, although none were found dead as a result of the spill (Hunt, 2012a). The cleanup involved with the 2010 spill included construction of an earthen levee, hay bale barriers in the stream, slurry removal with vacuum trucks, and designation of a contamination zone (Belmont Soil and Water Conservation District, 2013). In 2012 Ohio Valley Coal Company and Murray Energy pled guilty to two counts of water pollution violations for the two spills. The companies spent at least \$6 million to build a new slurry pipeline, and paid more than \$1 million in state and federal fines, including (Hunt, 2012b; U.S. District Attorney, 2012):

- \$455,000 to Ohio EPA for fines and restitution,
- \$500,000 in federal fines,
- \$95,000 to Ohio DNR for 18 days of cleanup and losses to fish and wildlife.

Estimated cleanup costs are not publicly available.

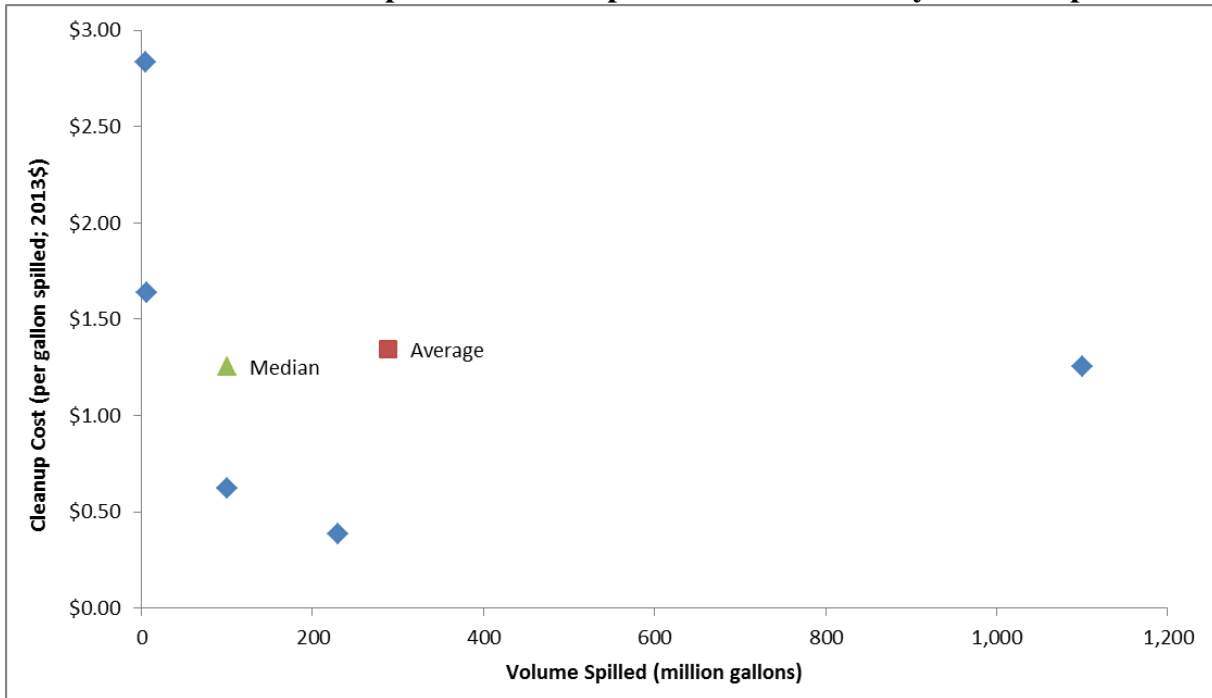
4 Summary

Based on the five available data points, Massey, Martins Creek, TVA Kingston, TVA Widows Creek, and Oak Creek, the mean unit cost of cleanup is \$1.35 per gallon spilled, while the median is \$1.25 (Exhibit 1 and Exhibit 2). Note that the average and median unit cleanup costs shown in the Exhibits are based on the average/median of the unit costs shown in the last column. The weighted average across incidents [total cleanup costs (\$1.55 billion) divided by the total volume spilled (1.44 billion gallons)] yields unit cleanup costs of \$1.08 per gallon spilled.

Exhibit 1. Documented Cleanup Costs from Impoundment Releases

Incident	Volume Spilled (million gallons)	Cleanup Cost (millions; 2013\$)	Unit Cleanup Cost (2013\$)
Oak Creek	5	\$13	\$2.83
TVA Widows Creek	6	\$10	\$1.64
Martins Creek	100	\$62	\$0.62
Massey	230	\$89	\$0.39
TVA Kingston	1,100	\$1,379	\$1.25
<i>Average</i>	288	<i>\$311</i>	<i>\$1.35</i>
<i>Median</i>	<i>100</i>	<i>\$62</i>	<i>\$1.25</i>

Exhibit 2. Unit Cleanup Costs from Impoundment Releases by Volume Spilled



5 References

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APPENDIX R

Research on Natural Resource Damage Estimates from Coal Ash Impoundment Releases (WA 0-05, Task 9)

Memorandum

Environment and Resources



Date April 14, 2014

To James Covington, EPA/OW/EAD

From Emily Giovanni and Isabelle Morin

Subject Research on Natural Resource Damage Estimates from Coal Ash Impoundment Releases (WA 0-05, Task 9)

This memo summarizes the natural resource damages (NRD) estimate for releases from coal ash impoundments.

Ideally, we would obtain NRD for the impoundment releases for which we also have cleanup costs, but we did not find NRD settlement values for these releases.¹ This memo therefore presents NRD estimates for damages to resources similar to those that may be affected by impoundment releases, based on available literature. Overall, we find that the mean NRD assessments represent 4 percent of mean impoundment release cleanup costs.

1 NRD Cases Documented by Israel (2006; 2013)

Israel (2006) provides a detailed state-by-state summary of NRD programs, including some prominent NRD cases (arising from oil spills, chemical spills, and other incidents) in each state. Israel (2013) provides an updated version of the accounting with additional cases identified since the 2006 study.

The Appendix lists the 137 NRD cases from Israel (2006; 2013) that provide quantitative estimates of NRD restoration and compensation costs. In extracting NRD assessment data from Israel, therefore, we used only the relevant values. NRD does not include cleanup costs (or legal and transaction costs, if reported) but includes only the resource restoration and compensation values. For example, in one case, Israel (2006) reported that "In total, the State's claim was \$764 million, \$342 million of which was restoration cost damages, \$410 million was compensable value damages, and \$12 million was assessment and legal costs." For this case, we used the sum of \$342 million and \$410 million as NRD (i.e., excluded assessment and legal costs).²

¹ We found information about NRD assessments for two cases: Martin's Creek and Kingston. We could not find settlement values for either case since the assessment or legal proceedings are ongoing (e.g., PPL's 2012 annual report notes that "a decision by the court is still pending"). See Abt Associates memorandum "Research on Cleanup Costs for Coal Ash Impoundment Releases," dated March 13, 2014.

² We used values for individual cases discussed in the study, focusing exclusively on NRD and excluding or subtracting assessment costs when those costs were reported separately. We also excluded NRD values that represent the aggregate of several cases when it was not possible to discern NRD for individual cases.

2 Calculation of Unit NRD

Releases resulting from impoundment failures may affect resources similar to those that were affected by some of the NRD cases identified in Israel (2006; 2013) and therefore have similar NRD costs. However, some of the 137 cases described by Israel (2006; 2013) affect resources that are unlikely to be affected by impoundment releases considered for this analysis, or result from substantively different circumstances. EPA received comments on the proposed Steam Electric ELG analysis noting significant differences between NRD resulting from impoundment releases and those assessed for legacy pollution such as CERCLA (Comprehensive Environmental Response, Compensation, and Liability Act, commonly known as Superfund) sites.³ In selecting relevant damage cases, therefore, we excluded cases where damages affected only groundwater or ocean/marine waters. We also excluded cases associated with Superfund sites, since these are generally associated with legacy pollution, which may be different from discrete releases. As shown in Appendix A, we excluded a total of 74 cases: 11 cases that affected groundwater only, 25 cases that took place offshore or in marine waters, and 38 cases associated with Superfund sites.

Exhibit 1 shows summary statistics for the 65 remaining NRD settlements, compared to the summary statistics for the cleanup costs identified in a previous memo.

Exhibit 1. NRD Settlements Summary Statistics			
	Natural Resource Damages (2013\$)¹	Cleanup Costs (2013\$)²	NRD as a Percent of Cleanup Costs
Minimum	\$44,000	\$10,000,000	0%
Median	\$1,965,000	\$62,000,000	3%
Mean	\$13,723,000	\$311,000,000	4%
Maximum	\$439,545,000	\$1,379,000,000	32%
1. Based on Israel (2006; 2013); updated using changes in the GDP. If a year is not provided for a case, we updated from the year of the study in which the case was identified (2006 or 2013).			
2. Based on cleanup costs documented in previous Abt Associates memorandum, "Research on Cleanup Costs for Coal Ash Impoundment Releases," dated March 13, 2014.			

To estimate expected NRD costs for future impoundment releases, we assume that the NRD varies depending on the magnitude of the release, as indicated by cleanup costs, and represents a certain percentage of cleanup costs (U.S. EPA, 2013). To derive a per-gallon estimate of the expected NRD value for future releases, we divided the mean NRD settlement of \$13.7 million by the mean cleanup cost (\$311 million⁴). We use the mean to be consistent with the approach used to estimate cleanup costs. This

³ For example, commenters noted that would expect NRD costs for impoundment releases to be relatively low "compared to NRD costs related to sites regulated under CERCLA, because the environmental damages for sites regulated under CERCLA have often been in place for many years, whereas the damages related to CCR impoundment failures will generally be of shorter duration." (Comment #EPA-HQ-OW-2009-0819-4655-A2).

⁴ As documented in a previous Abt Associates memorandum, "Research on Cleanup Costs for Coal Ash Impoundment Releases," dated March 13, 2014.

calculation yields an NRD estimate of **4 percent of cleanup costs, or \$0.05 per gallon spilled** (4 percent of \$1.35 /gallon).⁵

Note that this estimate provides an approximate value for NRD resulting from impoundment failures as a function of the volume of CCR slurry released and is appropriate for analyses that look at NRD over a range of locations and circumstances; we expect that actual damages from any given release would be highly location- and release-specific.

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⁵ This is compared to 6 percent of cleanup costs used for the proposed Steam Electric ELG analysis, which was based on the ratio of the median NRD to median cleanup costs (U.S. EPA, 2013).

Appendix: 137 NRD Settlements 1967 to 2013 Documented by Israel (2006; 2013)

Row	State	Original NRD Amount	Year	Updated NRD Amount	Case	Notes	Included or Excluded	Reason for Exclusion
1	AL	\$491,976	2006	\$596,000	Shelby County Train Derailment	soybean spill leading to damage of aquatic life (fish, mussels, and snails)	Included	
2	AL	\$1,000,000,000	2011	\$1,081,352,000	Deepwater Horizon	oil spill in Gulf of Mexico	Excluded	Ocean
		\$600,000,000	2013	\$600,000,000			Excluded	Ocean
3	AK	\$644,017	1997	\$1,257,000	M/V Kuroshima	oil spill along coastline	Excluded	Ocean
4	AK	\$1,000,000,000	1989	\$2,968,963,000	Exxon Valdez	Exxon Valdez	Excluded	Ocean
5	AZ	\$7,000,000	2013*	\$7,000,000	ASARCO LLC	three historic mining sites	Excluded	CERCLA
6	AZ	\$6,800,000	2012	\$7,031,000	Freeport-McMoRan Corp Morenci Mine	hazardous substance release	Included	
7	AR	\$2,000,000	1987	\$6,898,000	Vertac Chemical Corporation Superfund Site	dioxin release from herbicide/pesticide plant	Excluded	CERCLA
8	CA	\$16,300,000	1990	\$45,789,000	American Trader Oil Spill	biological injury (effects on fish and birds) from a 416,598 gallon crude oil spill	Excluded	Ocean
9	CA	\$14,000,000	2001	\$22,133,000	Cantara Loop/ Dunsmuir Chemical Spill	spill of 19,000 gallons of an herbicide which damaged habitat and fish	Included	
10	CA	\$30,000,000	2005	\$38,481,000	Montrose Chemical	long-time accidental and purposeful discharges of DDT	Excluded	CERCLA
11	CA	\$32,300,000	2007	\$37,469,000	Cosco Busan Oil Spill	spill of 53,000 gallons of bunker fuel	Excluded	Ocean
12	CA	\$5,400,000	1986	\$19,761,000	Apex Houston Oil Spill	spill of 25,800 gallons of crude oil, killing 10,577 birds	Excluded	Ocean
13	CA	\$10,800,000	1988	\$34,538,000	Shell/Martinez Oil Spill	release of 400,000 gallons of crude oil into creek	Included	
14	CA	\$2,700,000	1991	\$7,346,000	Exxon Mobil/Santa Clara River Oil Spill	spill of 74,000 gallons of crude oil	Included	
15	CA	\$1,400,000	1992	\$3,596,000	Avila I Oil Spill	spill of 24,200 gallons of crude oil into Pacific Ocean	Excluded	Ocean

Row	State	Original NRD Amount	Year	Updated NRD Amount	Case	Notes	Included or Excluded	Reason for Exclusion
16	CA	\$1,400,000	1993	\$3,419,000	McGrath Oil Spill	release of 87,150 gallons of crude oil into McGrath Lake and the Pacific Ocean	Excluded	Ocean
17	CA	\$7,100,000	1994	\$16,318,000	ARCO/Santa Clara River Oil Spill	release of 190,000 gallons of crude oil into 16 miles of river	Included	
18	CA	\$3,625,000	1996	\$7,517,000	SS Cape Mohican Oil Spill	96,000 gallons of intermediate fuel oil released, with 40,000 gallons spilling into San Francisco Bay	Excluded	Ocean bay
19	CA	\$4,820,000	1997	\$9,405,000	M/V Kure/Humboldt Bay Oil Spill	bunker fuel oil spill killing birds and affecting saltmarsh, mudflats, kayaking, camping, surfing	Excluded	Ocean bay
20	CA	\$1,900,000	1997	\$3,707,000	Torch/Platform Irene Oil Spill	oil release into ocean, killing 700 birds, affecting sandy and rocky shoreline habitat	Excluded	Ocean
21	CA	\$3,900,000	1998	\$7,208,000	T/V Command Oil Spill	3,000 gallons of intermediate bunker oil discharged, damaging birds, shoreline habitat, recreational beach use	Excluded	Ocean
22	CA	\$6,710,000	1999	\$11,661,000	M/V Stuvyesant/Humboldt Oil Spill	2,000 gallons of intermediate fuel oil spilled into Pacific Ocean, killing 2,405 birds, damaging coastal beaches, shrimp, fish, and beach use	Excluded	Ocean
23	CA	\$358,000	2000	\$584,000	East Walker River Oil Spill	3,600 gallons of fuel oil spilled, impacting 15 miles of river	Included	
24	CA	\$6,000,000	2000	\$9,795,000	Avila II Oil Contamination	numerous pipeline leaks caused underground plume of oil products	Excluded	Groundwater only
25	CA	\$1,150,000	2004	\$1,573,000	Kinder-Morgan/Suisun Marsh Oil Spill	spill of 70,000 gallons of diesel into marsh	Excluded	Ocean
26	CA	\$950,000	2013*	\$950,000	Searles Valley Minerals/Searles Lake (Trona)	Hypersaline industrial wastewater discharged into large ponds	Included	
27	CA	\$9,000,000	2013*	\$9,000,000	Guadalupe Oil Field Contamination	pipeline leaks causing 80 plumes of diluent	Excluded	Ocean
28	CA	\$9,000,000	2013*	\$9,000,000	Iron Mountain Mine CERCLA Site	acid mine drainage over many decades	Excluded	CERCLA

Row	State	Original NRD Amount	Year	Updated NRD Amount	Case	Notes	Included or Excluded	Reason for Exclusion
29	CA	\$6,750,000	2013*	\$6,750,000	New Almaden Mine CERCLA Site	release of mercury in Guadalupe River watershed and south San Francisco Bay	Excluded	CERCLA
30	CA	\$2,850,000	2013*	\$2,850,000	Chevron/Castro	oil and mercury dischargers contaminating intertidal and sub-tidal mudflats	Included	
31	CA	\$850,000	2009	\$990,000	Dubai Star/San Francisco Bay Spill	400 gallons of intermediate fuel oil spilled, affecting shoreline, birds, human uses	Excluded	Ocean
32	CA	\$22,700,000	2007	\$26,333,000	S.S. Jacob Luckenbach Oil Spill	457,000 gallons of fuel released from a sunken ship, killing 51,569 birds between 1990 to 2003 and sea otters	Excluded	Ocean
33	CO	\$194,000,000	2009	\$226,019,000	California Gulch Site	superfund site with surface water and habitat remediation needs	Excluded	CERCLA
34	CO	\$27,500,000	1992	\$70,639,000	Rocky Mountain Arsenal	former weapons and chemicals manufacturing site	Excluded	CERCLA
35	CO	\$10,000,000	1994	\$22,983,000	Rocky Flats	former nuclear weapons manufacturer with plutonium, uranium, volatile organic compounds, metals, radionuclide materials, nitrates, and asbestos contamination	Excluded	CERCLA
36	CT	\$15,000,000	1977	\$120,787,000	Housatonic and Connecticut Rivers	PCB contamination from longtime discharges from a power plant	Excluded	
37	CT	\$2,700,000	1967	\$52,632,000	Quinnipiac River Basin	settlement funds to replace lost drinking water source from a landfill	Excluded	CERCLA
38	DE	\$27,500,000	2010	\$30,881,000	Athos I	discharge of 265,000 gallons into Delaware River and tributaries	Included	
39	FL	\$3,100,000	1999	\$5,387,000	Tampa Bay Oil Spill	362,000 gallons of fuel oil and other petroleum products, damaging beaches of shellfish beds	Excluded	Ocean
40	FL	\$1,200,000	2006*	\$1,455,000	Sapp Battery	metal contaminations in soil, surface water, groundwater, and wetlands from battery salvage	Excluded	

Row	State	Original NRD Amount	Year	Updated NRD Amount	Case	Notes	Included or Excluded	Reason for Exclusion
41	FL	\$77,000	2013*	\$77,000	Whitehouse Oil Pits Superfund Site	assessment costs and restoration of a wetland	Excluded	CERCLA
42	FL	\$3,600,000	1997	\$7,025,000	Alafia River	discharge of 50 million gallons of process water from a phosphogypsum stack breach	Included	
43	GA	\$11,800,000	2006	\$14,303,000	R.J. Schlumberger	PCB contamination	Excluded	CERCLA
44	HI	\$5,800,000	2013	\$5,800,000	M/V Cape Flattery	oil spill damaging 20 acres of coral reef, fish, algae, sea urchins, and other reef animals	Excluded	Ocean
45	ID	\$498,500,000	2009	\$580,775,000	Bunker Hill Mining Superfund Site	100 million tons of mining wastes in a river system; wildlife habitat damage, poisoning of birds and other wildlife	Excluded	CERCLA
46	ID	\$60,000,000	1995	\$131,504,000	Blackbird Mine Superfund Site	mining damage to surface water and wildlife (Chinook salmon)	Excluded	CERCLA
47	IL	\$1,843,000	2011	\$1,993,000	Former Indian Refinery	damages from various contaminants to groundwater, surface water, soils, and adjacent properties	Included	
48	IL	\$450,000	2007	\$522,000	Saline Branch and Salt Fork River	2 fish kills from sudden ammonia releases	Included	
49	IL	\$263,000	2001	\$416,000	Marathon Oil Company	numerous spills of crude oil and refined petroleum products impacting 29 counties	Included	
50	IL	\$154,648	2001	\$244,000	Vesuvius USA Corporation	spill of an industrial chemical into 3 tributaries of the Embarras River	Included	
51	IL	\$105,000	2013*	\$105,000	Williams Pipeline Company	pipeline leak of 10,000 gallons of gasoline and diesel oil into tributary of Salt Creek	Included	
52	IN	\$86,000,000	1998	\$158,936,000	Grand Calumet	dredging after PCB, oil, benzene, cyanide, and heavy metal contamination from Stell manufacturer, plus restoration of habitat	Excluded	CERCLA

Row	State	Original NRD Amount	Year	Updated NRD Amount	Case	Notes	Included or Excluded	Reason for Exclusion
53	IN	\$6,250,000	2000	\$10,203,000	White River	excessive chemical discharges killing 4.6 million fish; note that the settlement was for \$14 million, \$6.25 million of which was for NRD	Included	
54	IN	\$600,000	2000	\$979,000	American Chemical Services	discharge of chemicals from storage drums	Included	
55	IN	\$31,309	1985	\$121,000	I. Jones Recycling, Inc.	hazardous waste release	Included	
56	IN	\$200,000	2009	\$233,000	Lakeland Disposal Landfill	waste leakage into groundwater, surface water, and sediments	Included	
57	IN	\$597,000	1999	\$1,037,000	Waste Inc. Landfill	liquid waste drainage into aquifer, creek, and surrounding wetlands	Included	
58	KS	\$1,200,000	2008	\$1,369,000	Cherokee County Superfund Site	runoff from zinc and lead mine tailings that entered local streams and contaminated groundwater	Excluded	CERCLA
59	KY	\$2,500,000	2007	\$2,900,000	Russellville Plant	PCB pollution in groundwater, streams, and rivers	Included	
60	LA	\$750,000	2011	\$811,000	Calcasieu Estuary and Bayou Verdine	release of hazardous substances to soil and water, impacting assorted benthos and other marine resources	Excluded	CERCLA
61	ME	\$1,000,000	1996	\$2,074,000	Julie N Oil Spill	Oil spill; 130 acres of habitat enhancement/acquisition	Included	
62	ME	\$125,000	1994	\$287,000	F. O'Connor Superfund Site	groundwater damage from PCBs and solvents	Excluded	CERCLA
63	ME	\$930,000	1997	\$1,815,000	Maine Yankee	petroleum, solvents, and radiological materials from nuclear power plant	Included	
64	ME	\$160,440	2013*	\$160,000	S.D. Warren Facility	waste from manufacture of coated paper which contaminated groundwater	Excluded	Groundwater only
65	MD	\$2,700,000	2000	\$4,408,000	PEPCO Spill	oil spill; restoration of wetlands, oyster beds, waterfowl nesting areas, and terrapin habitat	Included	
66	MD	\$507,300	2007	\$588,000	Spectron, Inc. Superfund Site	contamination and oil from site which migrated to Little Elk Creek	Excluded	CERCLA

Row	State	Original NRD Amount	Year	Updated NRD Amount	Case	Notes	Included or Excluded	Reason for Exclusion
67	MA	\$20,200,000	1992	\$51,888,000	AVX/New Bedford Harbor	water column, sediments, shellfish, birds, anadromous fish, recreational fishing, beach usage	Excluded	CERCLA
68	MA	\$1,353,000	1993	\$3,304,000	Charles George Landfill	landfill pollution, gases, leachate, contamination, migratory birds, fish	Included	
69	MA	\$157,000	1995	\$344,000	PSC Resources	groundwater and wetlands	Included	
70	MA	\$3,100,000	1998	\$5,729,000	Nyanza/ Sudbury River	surface water (riverine habitat), wetlands, fisheries, other wildlife, recreational use	Included	
71	MA	\$30,000	1999	\$52,000	Hallmark/ Mystic River	surface water (riverine habitat), recreational use	Included	
72	MA	\$19,700,000	2000	\$32,159,000	General Electric/ Housatonic River	ground and surface water, nesting habitats, recreational fishing and boating, various aquatic organisms and birds	Included	
73	MA	\$30,000	2003	\$44,000	Sulfuric Acid Spill/ North River	Various aquatic resources, aquatic fish, amphibians, invertebrates, and plant species	Included	
74	MA	\$500,000	2004	\$684,000	Coal Tar Deposits/ CT River	various aquatic resources, endangered species	Included	
75	MA	\$142,000	2004	\$194,000	Posavina Oil Spill/ Chelsea Creek	coastal land and habitat, salt water vegetation, migratory birds, fish	Excluded	Ocean
76	MA	\$1,300,000	2007	\$1,508,000	Textron Systems Corporation/Mass Military Reservation Superfund Site	groundwater	Excluded	CERCLA
77	MA	\$312,500	2008	\$357,000	Global/Irving Chelsea Creek Oil Spill	surface water, shoreline, wetlands, salt marsh	Included	
78	MA	\$747,000	2010	\$839,000	Rubchinuk Landfill Site	community use	Included	
79	MA	\$1,650,000	2010	\$1,853,000	Sutton Brook Disposal Area Superfund Site	groundwater, biological resources and their habitats	Excluded	CERCLA
80	MA	\$1,094,000	2011	\$1,183,000	Blackburn and Union Privileges Superfund Site	groundwater, biological resources and their habitats	Excluded	CERCLA
81	MA	\$6,076,000	2011	\$6,570,000	Bouchard B-120 Buzzards Bay Oil Spill	aquatic and shoreline, ram island shoreline, recreation and shellfish, and piping plovers	Excluded	Ocean bay

Row	State	Original NRD Amount	Year	Updated NRD Amount	Case	Notes	Included or Excluded	Reason for Exclusion
82	MA	\$875,000	2012	\$905,000	GM Assembly Plant in Framingham	streambed, banks, and surrounding wetlands; birds, wildlife, and benthic macroinvertebrates	Included	
83	MA	\$4,250,000	2012	\$4,395,000	Pharmacia Corp./Bayer CropScience Superfund Site	wetland, river, and lake habitat; fish, turtles, amphibians, and migratory birds	Excluded	CERCLA
84	MI	\$807,490	1989	\$2,397,000	Verona Well Field	groundwater contamination from leaking solvents	Excluded	Groundwater only
85	MI	\$26,200,000	1998	\$48,420,000	Saginaw River and Bay	PCB release into Saginaw River	Included	
86	MS	\$3,000,000	1999	\$5,214,000	Genesis Pipeline Spill	crude oil spill; surface water, sediments, shoreline habitat, wildlife	Included	
87	MO	\$49,000	2013*	\$49,000	Cominco/Halliburton	seven lead and copper metal concentrate spill sites	Included	
88	MO	\$20,100,000	2009	\$23,417,000	Newton County Mine Tailings Superfund Site	releases of cadmium, lead, and zinc to groundwater, surface water, sediments, aquatic and terrestrial plants and organisms, aquatic mammals, fish, aquatic and terrestrial invertebrates, and migratory birds	Excluded	CERCLA
89	MO	\$41,200,000	2009	\$48,000,000	Southeast Missouri Lead Mining District	four mine sites impacting surface water, geological resources, groundwater, and aquatic and terrestrial biota	Excluded	CERCLA
90	MT	\$138,000,000	1999	\$239,823,000	Atlantic Richfield Company	decades of mining and mineral processing releasing hazardous substances	Included	
		\$169,000,000	2008	\$192,848,000			Included	
		\$5,900,000	2009	\$6,874,000			Included	
91	MT	\$37,000,000	2008	\$42,221,000	Mike Horse Dam	Dam failure in 1975 due to heavy rains. Contaminated tailings were washed into the Beartrap Creek and the Upper Blackfoot River	Included	
92	MT	\$1,600,000	2012	\$1,654,000	Silvertip Pipeline Oil Spill	63,000 gallons of oil spilled into Yellowstone River	Included	
93	NV	\$859,528	2013	\$860,000	Rio Tinto Mine	abandoned copper mine waste disposal in Mill Creek	Included	

Row	State	Original NRD Amount	Year	Updated NRD Amount	Case	Notes	Included or Excluded	Reason for Exclusion
94	NH	\$1,500,000	2005	\$1,924,000	Coakley Landfill Superfund Site	contamination of wetlands with various pollutants; restoration of 338 acres of degraded saltmarsh	Excluded	CERCLA
95	NJ	\$20,000	2013*	\$20,000	In re Former Owens-Illinois Closure Site	contamination of groundwater	Excluded	Groundwater only
96	NJ	\$40,462,000	2013*	\$40,462,000	In re Phelps Dodge Site	hazardous waste discharge into groundwater	Excluded	Groundwater only
97	NJ	\$150,000	2009	\$175,000	In re Jimmie's Raceway Service Station	contamination of soil and groundwater from gas station	Excluded	Groundwater only
98	NJ	\$3,218,700	2009	\$3,750,000	Combe Fill South Landfill Superfund Site	contamination of groundwater and nearby brook	Excluded	CERCLA
99	NM	\$1,000,000	2000	\$1,632,000	Sparton Technology Site	damage to groundwater from discarded solvents and plating wastes	Excluded	Groundwater only
100	NM	\$1,100,000	2006*	\$1,333,000	Albuquerque ATSF Site	railroad tie treating plant; damages to groundwater and wildlife habitat	Included	
101	NM	\$13,000,000	2010	\$14,598,000	Freeport McMoRan	damages to groundwater, wildlife, and wildlife habitat	Excluded	Groundwater only
		\$5,500,000	2012	\$5,687,000			Included	
102	NM	\$30,000	2004	\$41,000	SOHIO L-Bar Facility	uranium tailings which contaminated groundwater	Excluded	Groundwater only
103	NM	\$7,500,000	2006	\$9,091,000	State of New Mexico v General Electric Company et al.	contaminated groundwater from a Superfund site	Excluded	CERCLA
104	NY	\$20,300,000	2013	\$20,300,000	St Lawrence River in Massena	PCB contamination in a river	Excluded	
105	NY	\$12,000,000	2006	\$14,545,000	Lake Ontario System	release of dangerous chemicals into Lake Ontario System	Included	
106	OH	\$13,750,000	2008	\$15,690,000	Fernald Uranium Products	uranium products (over 1,000 acres) damaging groundwater	Excluded	CERCLA
107	OH	\$5,500,000	2012	\$5,687,000	Ashtabula River	remediation of contaminated sediment	Excluded	CERCLA
108	OH	\$2,040,000	2006	\$2,473,000	Ohio River	restoration of damage to mussels, fish, and snails from contamination from a metals company	Included	

Row	State	Original NRD Amount	Year	Updated NRD Amount	Case	Notes	Included or Excluded	Reason for Exclusion
109	OK	\$300,000	2007	\$348,000	Double Eagle Superfund Site	contamination of groundwater by hazardous waste	Excluded	CERCLA
110	OR	\$50,000	2013*	\$50,000	Whitaker Slough Cleanup	contamination of Whitaker Slough by electroplating wastewater	Included	
111	OR	\$100,000	2013*	\$100,000	Johnson Lake	overflow from settling ponds and stormwater discharges	Included	
112	OR	\$300,000	2009	\$350,000	Union Carbide Site	Claims related to waste from carbide and ferroallow processing contaminating the Columbia Slough.	Included	
113	PA	\$21,000,000	2009	\$24,466,000	Palmerton Zinc Superfund Site	injuries to aquatic and terrestrial resources from zinc and other metals	Excluded	CERCLA
114	PA	\$7,350,000	2006	\$8,909,000	Sinnemahoning Creek Watershed	spill of sodium hydroxide from train derailment, damaging several waterbodies	Included	
115	RI	\$8,000,000	2013*	\$8,000,000	North Cape Oil Spill	828,000 gallons of home heating oil spilled, killing at least 9 million lobsters, thousands of birds, and millions of clams, crabs, and fish	Excluded	Ocean
116	RI	\$1,415,000	2005	\$1,815,000	Calf Pasture Point and Allen Harbor Landfill	discharge of chemical wastes (chlorinated hydrocarbons and VOCs) into groundwater	Excluded	Groundwater only
117	RI	\$6,000,000	2011	\$6,488,000	Buzzard's Bay	oil spill injuring shoreline and aquatic resources, piping plovers, and recreational uses	Excluded	Ocean bay
118	RI	\$750,000	2013	\$750,000	Davis Liquid Waste Superfund Site	contamination of groundwater	Excluded	CERCLA
119	SC	\$121,000	2012	\$125,000	Cooper River/Charleston Harbo	release of 12,500 gallons of fuel oil affecting shoreline habitats, sediments, migratory birds, shellfish beds, and recreational shrimp baiting	Included	
120	SD	\$4,000,000	2006*	\$4,848,000	South Dakota v Homestake Mining Company	damage to surface and groundwater from metals (from mining)	Included	

Row	State	Original NRD Amount	Year	Updated NRD Amount	Case	Notes	Included or Excluded	Reason for Exclusion
121	TN	\$543,203	2002	\$831,000	Obed Wild and Scenic River Site	oil spill and fire in tributaries of the Obed Wild and Scenic River	Included	
122	TN	\$50,000	2010	\$56,000	U.S. Department of Energy's Oak Ridge Reservation	damages to fishing from release of hazardous substances and radioactive compounds	Included	
123	TX	\$3,120,000	2012	\$3,226,000	Malone Service Co. Disposal Facility	hazardous waste material that contaminated groundwater and migrated to Galveston Bay	Excluded	CERC LA
124	UT	\$37,000,000	1995	\$81,094,000	Southwest Jordan Valley	\$28 million in restoration of groundwater, damaged by historic mining, \$9 in compensation	Included	
125	UT	\$2,580,000	2007	\$2,993,000	Ensign-Bickford Trojan Facility	discharges from explosives manufacturing facility into groundwater (3 mile plume)	Excluded	Groundwater only
126	UT	\$3,500,000	2011	\$3,785,000	Red Butte Creek Oil Spill	pipeline rupture releasing oil into creek and other waters	Included	
127	VA	\$3,700,000	2003	\$5,399,000	Tazewell County Spill	1,300 gallons of a rubber accelerant, which damaged endangered species of freshwater mussels	Included	
128	VA	\$2,500,000	2001	\$3,952,000	Powell River	six million gallons of coal slurry release to river watershed (20 miles downstream), impacting fish, endangered mussels, aquatic habitat, bats, and migratory birds	Included	
129	WA	\$5,000,000	2006*	\$6,061,000	Elliot Bay/ Duwamish River	habitat development and restoration after damage from sewer discharges	Included	
130	WA	\$5,500,000	2005	\$7,055,000	Skykomish Facility	discharge of diesel fuel which leaked to water table	Included	
131	WA	\$9,000,000	1994	\$20,685,000	Tenyo Maru	release of 354,800 gallons of fuel oil and 97,800 gallons of diesel fuel, affecting coastal waters and shorelines and killing 4,300 seabirds	Excluded	Ocean
132	WA	\$512,857	2008	\$585,000	Crystal Mountain Emergency Generation Facility	release of 18,200 gallons of diesel fuel into creek	Included	

Row	State	Original NRD Amount	Year	Updated NRD Amount	Case	Notes	Included or Excluded	Reason for Exclusion
133	WV	\$2,040,000	2006	\$2,473,000	Ohio River	restoration of native freshwater mussels, snails, and fish in Ohio River	Included	
134	WV	\$500,000	2009	\$583,000	Consol Energy/Dunkard Creek	discharge of mining wastewater containing chloride, resulting in an algae bloom that killed thousands of fish, mussels, and amphibians	Included	
135	WI	\$35,000,000	2013*	\$35,000,000	Fox River/Green Bay	contamination from PCB and other discharges from paper mills	Excluded	CERCLA
136	WI	\$1,900,000	2012	\$1,965,000	Ashland Lakefront	contaminated sediments	Included	
137	WY	\$50,000	2013*	\$50,000	Gasoline Spill	restocking a surface water after a fish kills from a gasoline spill	Included	

APPENDIX S

Potential Impacts of EPA's 2012 CCR Final Rule on Future Beneficial Use of CCR

Potential Impacts of EPA’s 2012 CCR Final Rule on Future Beneficial Use of CCR

Note: This appendix presents beneficial use impacts for regulatory options developed and analyzed prior to EPA’s specification of the final rule. The option named Subtitle D-prime as presented in this appendix is the same as the analyzed option as presented in Section 5.3 of the main body of this regulatory impact analysis with one exception—Subtitle D-prime includes a restriction on large-scale fill applications. This restriction is not reflected in the analyzed option presented in Section 5.3. In addition, like the analyzed option in Chapter 5, Subtitle D-prime differs from the final rule with respect to the requirements for liners. More specifically, Subtitle D-prime (and the analyzed option in Chapter 5) would require that only new impoundments install liners that meet the rule specifications; existing impoundments would be allowed to continue operating until they reached terminal age under this option. In contrast, the final rule would require any unlined impoundment to close if it leaks. Similar to Subtitle D-prime (and the analyzed option), the final rule would also require liners for new impoundments.

This appendix describes the potential impacts of the coal combustion residue (CCR) final rule on the beneficial use of CCR. Specifically, it addresses (1) possible changes in future beneficial use due to changes in the costs of CCR disposal, (2) impacts related to new regulatory restrictions on beneficial use, and (3) the potential future reduction in beneficial use due to “stigma” under the Subtitle C option for the final rule (the stigma effect is not relevant to the Subtitle D, D-prime, and the Preferred (Subtitle D Clay and Composite) options for the CCR final rule). This appendix first summarizes the current state of CCR beneficial use, as well as current (i.e., baseline) beneficial use market trends. Following this presentation, this appendix describes potential changes in beneficial use due to each of the three factors listed above. In addition, this appendix estimates potential changes in future beneficial use associated with the four options for the CCR final rule and estimates the life cycle value of these potential changes.

To assess potential beneficial use impacts associated with the Preferred Option (Subtitle D Clay and Composite), this chapter uses impacts associated with Regulatory Option 2 (Subtitle D). Because the costs of compliance (i.e., avoided costs associated with beneficial use) are higher under Regulatory Option 2 than under the Preferred Option, these impacts may overate the beneficial use impacts of the rule.

S.1 CCR Beneficial Use Markets

The chemical and physical properties of CCRs allow for their use in a wide range of products. CCRs may be used as a component of various building materials (i.e., as a replacement for portland cement in concrete) or as a direct replacement for other virgin materials such as sand, gravel, or gypsum. The physical properties of CCRs make them especially useful for construction and industrial materials. Their size, shape, and chemical composition determine

their suitability for specific beneficial use applications. Specifications for their use in high-value applications, such as cement or concrete, are fairly stringent (in terms of size, shape and chemical composition), whereas CCRs with more variable physical characteristics may be used in low value uses such as structural fill. For this reason, relatively low-value applications that require large volumes of CCRs may present the greatest potential for expanded beneficial use.¹ Exhibit S-1 below summarizes the most common beneficial uses for CCRs. The exhibit excludes cenospheres as data on the primary beneficial uses of this material are not readily available.

¹ EPA, "Report to Congress: Wastes from the Combustion of Fossil Fuels." Vol. II. EPA-530-R-99-010, March 1999; its two volumes and Technical Document supporting materials are available at the EPA website <http://www.epa.gov/osw/nonhaz/industrial/special/fossil/regs.htm>

EXHIBIT S-1: COMMON BENEFICIAL USES FOR CCRs

CCR	BENEFICIAL USE
Fly Ash	Concrete: Concrete consists of a mixture of approximately 25% fine aggregate (sand), 45% gravel, 15% portland cement, and 15% water. Class C and Class F fly ash can replace a percentage of the portland cement component of concrete. Fly ash contributes to enhanced concrete strength and durability, and is typically less expensive than portland cement.
	Cement clinker: Clinker is an intermediary product of the portland cement manufacturing process. Clinker is formed when a raw mix of limestone, clay, bauxite, iron ore and quartz is heated in a kiln at high temperatures. Fly ash can be blended with limestone or shale and fed into the kiln to make clinker, which is then ground into portland cement.
	Structural fill: Structural fill is an engineered material used to raise or change the surface contour of an area and to provide ground support beneath building foundations. It can also be used to form embankments. Depending on the soil type, fly ash can replace a percentage (generally 50%) of virgin rock, dirt, sand or gravel in structural fill.
	Waste stabilization: Fly ash can be used in place of portland cement, cement kiln dust, or lime to solidify and harden wet or liquid waste before it is landfilled. Class C fly ash hardens by itself in contact with moisture, but Class F fly ash must be mixed with another hardening agent, such as portland cement, in order to be used in waste stabilization.
FGD Gypsum	Wallboard: Gypsum wallboard (drywall) is an interior finish in building construction. Wallboard is a layer of gypsum stucco sandwiched between two sheets of heavy paper. FGD gypsum can replace 100% of virgin gypsum in wallboard after excess moisture is removed.
	Agricultural soil amendment: FGD gypsum can be used to replace liming agents and to provide certain nutrients as an agricultural soil amendment for specific soil and crop types.
	Cement additive: In the production of portland cement, clinker is blended with a small amount of gypsum prior to grinding into finished portland cement. FGD gypsum can be used to offset virgin gypsum in cement manufacture.
Bottom Ash	Structural fill: Structural fill is an engineered material used to raise or change the surface contour of an area and to provide ground support beneath building foundations. It can also be used to form embankments. Bottom ash can be used to offset virgin sand and gravel in structural fill.
	Road base: A road base is a foundation layer underlying a pavement and overlaying a subgrade of natural soil or embankment fill material. It protects the underlying soil from the detrimental effects of weather conditions and from the stresses and strains induced by traffic loads. Bottom ash can be used to offset virgin sand or gravel in road base.
	Concrete: Bottom ash can be used as a coarse aggregate for concrete blocks, with its porous nature often qualifying the product for lightweight classification.
Boiler Slag	Blasting Grit: Blasting grit is an industrial abrasive used to shape, cut, sharpen, or finish a variety of surfaces and materials. Boiler slag can be used as a replacement for other slags or virgin sand as blasting grit.
	Structural fill: Structural fill is an engineered material used to raise or change the surface contour of an area and to provide ground support beneath building foundations. It can also be used to form embankments. Boiler slag is occasionally used to offset virgin sand and gravel in structural fill.
Fluidized Bed Combustion Ash	Mining applications: Fluidized bed combustion (FBC) ash can be placed into abandoned mines during reclamation to neutralize the acidity of mine drainage. EPA considers large fill operations to be disposal, and so would not likely consider mining applications a beneficial use, though it is tracked by ACAA.

S.1.2 Current Quantities of CCRs Generated & Managed

The American Coal Ash Association (ACAA) conducts an annual survey of coal-fired electric plants to collect data on the production, disposal, and use of CCRs in the U.S.² Exhibit S-2 below summarizes the results of ACAA's 2010 survey. The exhibit includes ACAA's estimates of CCR generation and disposal, as well as the quantities of CCRs used for the most common beneficial use applications. In 2010, coal-fueled electric power plants generated approximately 130 million short tons of CCRs. Of this quantity, power plants disposed of approximately 75 million short tons in landfills and beneficially used approximately 55 million short tons.³ These applications represent more than 80% of the current beneficial use of CCRs.⁴ An expanded version of Exhibit S-2 which details a more inclusive set of CCR beneficial use applications, is provided at the end of this appendix.

In addition to the quantities of CCR reported in the ACAA survey, stockpiles may provide another potential source of fly ash for certain beneficial uses. Industry sources estimate that between 100 million and 500 million tons of fly ash have accumulated in U.S. landfills since the 1920s, when disposal of fly ash in landfills began.⁵

² The ACAA survey is administered to both ACAA members and non-members. ACAA members account for approximately 40 percent of private power generation. Not all survey recipients complete the survey each year. ACAA extrapolates survey respondent data to the entire coal-fired electricity generation industry. To the extent that other coal-burning industries are not represented in the ACAA sample, the survey may underestimate the quantity of CCPs generated and/or beneficially used.

³ This figure includes CCRs used in mining applications, which EPA considers a "large-scale filling operation" and therefore considers it to be disposal under all three final rule options included in this RIA.

⁴ Relatively minor applications comprise the remaining 20 percent of CCP beneficial uses. These applications include uses such as blasting grit, soil modification and stabilization, snow and ice control, and agricultural uses.

⁵ Source: Personal communication with Dave Goss, ACAA and Tom Janson, WE Energies, November 27, 2006. The quantity of stockpiled fly ash in landfills that is available for beneficial use is unclear. The chemical composition of fly ash varies depending on the type of coal used, and only two types of fly ash—Class C fly ash and Class F fly ash—meet ASTM technical requirements for concrete. It is unclear how much of the estimated 100-500 million tons of stockpiled fly ash falls into one of these classes. In addition, exposure to moisture or contamination in the stockpiles can limit the beneficial use options of Class C ash, though this is not a concern with Class F ash. Information on these standards can be found at <http://www.astm.org>

EXHIBIT S-2: KEY BENEFICIAL USES FOR CCRs IN 2010 (MILLION SHORT TONS)

APPLICATION (INDUSTRY)	COAL FLY ASH	BOTTOM ASH	FGD GYPSUM	OTHER FGD MATERIAL	BOILER SLAG	FBC ASH	TOTAL
Concrete ^a (Construction)	11.0	0.6	0.0	0.0	0.0	0.0	11.7
Fill and road base ^b	8.3	3.9	0.5	0.8	0.1	0.1	13.7
Wallboard (Construction)	0.0	0.0	7.7	0.0	0.0	0.0	7.7
Total - Key Uses	19.3	4.5	8.1	0.9	0.1	0.1	33.0
Total - Other Uses ^c	4.0	2.5	1.7	0.1	1.3	0.0	9.6
Mining applications ^d	2.4	0.5	0.8	0.3	0.0	8.7	12.7
TOTAL - ALL USES	25.7	7.5	10.7	1.2	1.4	8.7	55.3
2010 QUANTITY GENERATED	67.7	17.8	22.0	10.1	2.3	10.3	130.2
2010 QUANTITY DISPOSED	42.0	10.3	11.3	8.9	0.9	1.5	74.8
UTILIZATION RATE (includes mining)	38%	42%	49%	12%	61%	85%	43%
UTILIZATION RATE (excludes mining)	34%	39%	45%	9%	61%	1%	33%
Notes: a. CCRs are frequently used as a replacement for a portion of Portland cement in the manufacture of concrete. b. "Fill" includes engineered structural fill, flowable fill, and waste stabilization. Note that this differs from the definition of fill and fill-like applications used in the beneficial use assessment in Section S.4 of this appendix. c. Presents quantities beneficially used in minor applications not included in this exhibit, including raw feed for cement clinker, soil modification, mineral filler for asphalt, snow and ice control, blasting grit, other gypsum panel products, and agriculture. d. FBC ash and other CCRs can be used in mine reclamation to refill mines and to help mitigate acid mine drainage. EPA considers large fill operations such as this use to be disposal and not a beneficial use. This table includes these tonnages to reflect current regulation and data. Sources: 1. ACAA, "2010 Coal Combustion Product (CCP) Production and Use Survey," accessed Feb. 24, 2012 at http://acaa.affiniscape.com/associations/8003/files/2010_CCP_Survey_FINAL_102011.pdf 2. Western Region Ash Group, "Applications and Competing Materials, Coal Combustion Byproducts," accessed at http://www.wrashg.org/compmat.htm.							

S.2 Beneficial Use Market Trends & Potential for Growth

S.2.1 Recent Trends in CCR Markets

The term "fly ash" was first used in the United States in the late 1930s, and coal ash was used as a cement replacement in the construction of Montana's Hungry Horse Dam in 1949.⁶ Major efforts to increase the beneficial reuse of CCRs in the United States began in the late 1970s and

⁶ Rustu S. Kalyoncu, "Coal Combustion Products" USGS, 2000.
<http://minerals.usgs.gov/minerals/pubs/commodity/coal/874400.pdf>

early 1980s. In the 1980 amendments to RCRA, EPA specifically exempted “fly ash waste, bottom ash waste, slag waste, and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels” from being listed as hazardous waste. Both the generation and the beneficial use of CCRs subsequently increased as new approaches were identified in the construction sector

EPA initiated two programs to encourage the beneficial use of CCRs. In 1995, the Agency issued the first Comprehensive Procurement Guidelines (CPG), which require all “procuring agencies” (federal agencies and all agencies and contractors that use appropriated federal funds) to purchase certain products, such as concrete, with the maximum level of recycled products, including CCRs. In addition, EPA initiated the Coal Combustion Product Partnership (C2P2) in 2001 to coordinate efforts between government and industry to increase the beneficial use of CCRs. C2P2 led to noticeable advances in the beneficial use of most CCRs; as of 2012 the program is on hiatus pending the EPA’s final rule on CCRs.⁷

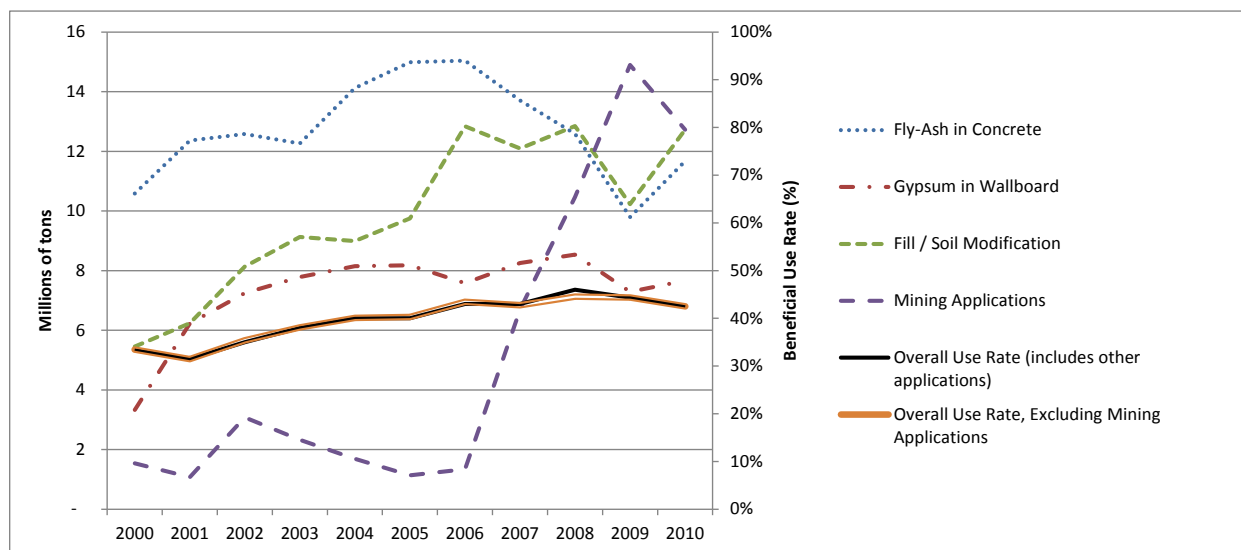
Exhibit S-3 below illustrates some of the recent trends in the major beneficial uses of CCRs. As indicated in the exhibit, the use of fly-ash in concrete has been dominant among beneficial use applications over the past ten years, though its use declined with the decrease in concrete demand for construction during the recent economic downturn. This decline has been offset by an increase in the use of other CCRs, keeping the overall beneficial use rate on an upward trajectory, with the exception of a small decline from 2008 through 2010. Exhibit S-4 also shows a sharp increase in beneficial use in mining applications. This is due to the inclusion by ACAA, after 2006, of FBC ash as a beneficial use in mining.⁸ The slight downturn in the overall use rate shown in the exhibit between 2008 and 2010 coincides with the economic downturn, and is consistent with other construction trends.⁹

⁷ Ed Chu and Ian Lange, “Evaluating Market-Making Voluntary Programs: The Case of Coal Combustion Products Partnership,” presented 2008.

⁸ EPA and the Office of Surface Mining, Reclamation, and Enforcement are jointly developing regulations that may affect the use of CCRs as mine fill. The definition of beneficial use specified in this rule may differ from the ACAA definition.

⁹ The ACAA has argued that uncertainty and anxiety surrounding the EPA’s regulatory discussions of CCR have also been a factor (ACAA comments, EPA-HQ-RCRA-2009-0640, pp. 3, 24-5). However, qualitative data that isolates the economic downturn from any regulatory impacts is not available, making this claim impossible to evaluate. New data from the 2010 ACAA survey also show an upturn in construction use, further suggesting that the downturn in 2008-2009 was due to the larger economy and not to concerns over the rulemaking (see Exhibit S-4 of this appendix).

EXHIBIT S-3. KEY BENEFICIAL USE QUANTITIES 2000-2010 (ACAA)



Note: The beneficial use tonnages represented by the dashed lines in the exhibit track with the left axis, and the beneficial use rate is measured on the right axis.

S.2.2 Potential for Growth in CCR Beneficial Use Markets

Growth in beneficial use of CCRs will depend on the demand for particular uses, the supply of CCRs, and the physical properties of these materials. With respect to demand, the research community is constantly exploring technological innovations to identify new beneficial uses for CCRs. Accommodating the increases in demand associated with these technological innovations will require a steady supply of CCR from coal-fired electricity producers. Based on projections from the Energy Information Administration, coal-fired electricity generation will continue to grow at a modest rate through 2035, ensuring a steady stream of supply.¹⁰ As noted above, however, CCRs generated by coal-fired power plants must meet the technical specifications of individual beneficial use applications. Thus, future growth in beneficial use will also depend on future trends in the physical characteristics of CCRs. These characteristics are a function of power plants' CCR handling practices (e.g., whether they are dry or wet handled) and the air pollution controls employed by power plants (e.g., power plant mercury controls may lead to increased mercury concentrations in CCRs).

More specific factors affecting the growth potential for the three most significant beneficial uses for CCRs are as follows.

- Cement Substitute in Concrete.** U.S. power plants generated approximately 25 million tons of fly ash in 2010, and, in the same year, U.S. production of portland cement was more than 66 million tons, most of which is used in the production of concrete.¹¹ Because fly ash can be used as a one-to-one replacement for portland cement in the production of concrete, these values suggest that all Class C and F fly ash could, in

¹⁰ See U.S. Energy Information Administration, *Annual Energy Outlook 2011*, April 26, 2011.

¹¹ Portland cement estimate from USGS, Mineral Commodity Summaries 2012, 2012 and the fly ash estimate is from ACAA, 2010 Coal Combustion Product (CCP) Production & Use and Survey Report, released December 14, 2011.

theory, substitute for cement in concrete production. The American Society for Testing Materials (ASTM) standards recommend, however, that fly ash content in concrete be limited to 25%, and the percentage is often significantly lower than this. Nonetheless, recent technological innovations have resulted in durable concretes in which fly ash makes up at least 50% of the total cementitious materials.¹² These innovations, combined with suggestions that there should be no limit on the use of fly ash as a cement substitute in concrete, may contribute to increased beneficial use of fly ash in the future.¹³ The CPGs also encourage increased use of fly-ash in concrete in federally-funded construction projects.

- **FGD Gypsum.** Once excess moisture is removed from FGD gypsum, a wallboard plant may substitute this material for all virgin gypsum. Currently, 50% of all FGD gypsum is recycled, primarily in wallboard construction, and roughly 30% of wallboard contains FGD gypsum (also referred to as synthetic gypsum).¹⁴ Growth in the beneficial use of FGD gypsum will depend on the virgin gypsum prices and investment decisions in the domestic wallboard industry. Using FGD gypsum in wallboard production requires different capital equipment from that employed at plants using virgin gypsum. If virgin gypsum prices increase, the return on investment for this equipment will increase, and more plants will convert to FGD gypsum, increasing demand. Beneficial use applications for FGD gypsum other than wallboard are emerging but are currently limited.
- **Fill.** As indicated in Exhibit S-3 above, the use of CCRs as fill is significant at more than 13 million tons per year. Approximately 190 million tons of sand and gravel were sold in the U.S. in 2010 for fill and fill-like applications.¹⁵ Thus, the total potential for increased beneficial use of CCRs in fill applications is substantial.

For most other CCR applications, markets for beneficial use have at least modest capacity for growth. EPA efforts to expand these markets by targeting well-accepted beneficial use practices may help overcome technical, administrative and informational hurdles to beneficial use and expand the use of these practices. It is important to note, however, that growth for two applications, mining fill and blasting grit, may be limited. Forthcoming regulations jointly developed by EPA and the Office of Surface Mining, Reclamation, and Enforcement may limit growth in demand for CCR in mine fill applications. In addition, this RIA anticipates little to no growth in the beneficial use market for boiler slag in blasting grit applications, as this is a mature market in which the beneficial use rate for boiler slag is already high.¹⁶

¹² National Technical Information Service, "Fly Ash Facts for Highway Engineers" (2003). <http://www.fhwa.dot.gov/pavement/recycling/fafacts.pdf>

¹³ Karthik Obla, "Specifying Fly Ash for Use in Concrete" (*Concrete InFocus*, Spring 2008). http://www.nrmca.org/research/cif/spring_08_fly_ash.pdf

¹⁴ ACAA, "2010 Coal Combustion Product (CCP) Production and Use Survey," accessed Feb. 24, 2012 at http://acaa.affiniscape.com/associations/8003/files/2010_CCP_Survey_FINAL_102011.pdf and Environmental Building News, August, 2010. <http://www.buildinggreen.com/auth/article.cfm/2010/7/30/Synthetic-Gypsum/>

¹⁵ U.S. Geologic Survey, *2009 Minerals Yearbook: Sand and Gravel, Construction [Advanced Release]*, July 2011. Fill and fill-like applications include (1) concrete aggregates (including concrete sand), (2) asphaltic concrete aggregates and other bituminous mixtures, (3) road base and coverings, (4) fill, and (5) snow and ice control.

¹⁶ For data on the beneficial use of boiler slag in blasting grit applications, see ACAA, "2010 Coal Combustion Product (CCP) Production and Use Survey," accessed Feb. 24, 2012 at http://acaa.affiniscape.com/associations/8003/files/2010_CCP_Survey_FINAL_102011.pdf.

This RIA projects the change in CCR beneficial use over time based on the projected trend in CCR generation and this assessment's projection of the change in the CCR beneficial use rate. For each year in the analytic time horizon, this RIA multiplies the estimate of CCR generation by the estimated CCR beneficial use rate, as summarized by Equation S-1. The linear program that we use to assess the rule's beneficial use impacts (see description below) calibrates to the baseline projection derived from Equation S-1.

$$\text{(Equation S-1) } BU_t = R_t \times G_t$$

Where BU_t = Tonnage of CCR beneficially used at time t ;

R_t = Beneficial use rate at time t ; and

G_t = Tonnage of CCR generated at time t .

As described in Chapter 2, this RIA estimates the baseline change in CCR generation based upon the change in domestic coal-fired electricity production as projected by the Energy Information Administration (EIA). To estimate the change in the beneficial use rate over time, this RIA extrapolated from the annualized growth in the beneficial use rate implied by the historical trend from 2002 through 2009.¹⁷ In 2002, the beneficial use rate was approximately 35%, and the corresponding rate for 2009 was 41%. These data imply that the beneficial use rate grows at an annual compounded rate of approximately 2.3% per year.¹⁸ This RIA applies this growth rate through the year 2035 consistent with the forecast horizon in the EIA projections of coal-based electricity generation. Because of the significant uncertainty associated with projecting beyond 2035, this RIA assumes that the post-2035 beneficial use rate and the quantity of CCR beneficially used remain constant at 2035 levels.

This RIA's projection of the beneficial use rate does not reflect beneficial use data for years prior to 2002. Although such data are available, 2002 represents the first year when CCR beneficial use reflected the full effects of EPA's Coal Combustion Partnership Program (C2P2). Therefore, if this RIA's extrapolation of the beneficial use rate were to reflect pre-2002 data, the analysis would overestimate growth in beneficial use over time. The establishment of C2P2 represented a one-time event that had a significant effect on the beneficial use rate. If this RIA were to develop a growth rate that reflected beneficial use for years both before and after C2P2's implementation, the analysis would implicitly assume the repeated occurrence of events similar to the establishment of C2P2. In addition, data for years prior to 2002 likely would not reflect current economic conditions as well as more recent data and would therefore be a less suitable basis for projections than more recent data from the past decade.

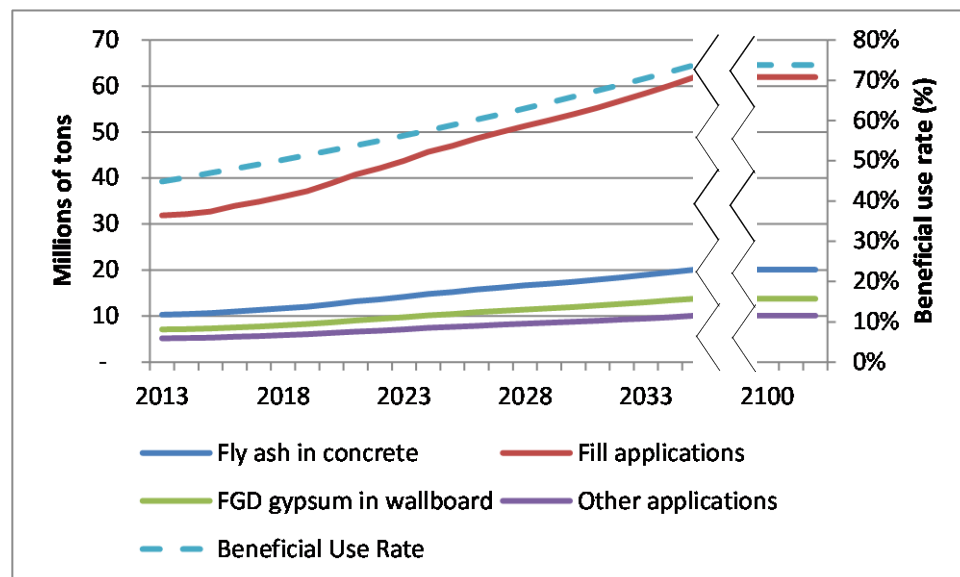
Exhibit S-4 presents the projected beneficial use of CCR by beneficial use application and also includes the estimated beneficial use rate. As indicated in the exhibit, this RIA estimates that the beneficial use rate will increase to approximately 74% by 2035. In addition, summing across beneficial use applications, beneficial use is projected to rise to approximately 106,000 tons per

¹⁷ The baseline projection of CCR beneficial use and the beneficial use impact analysis presented in this chapter were developed prior to the release of the ACAA's 2010 beneficial use data.

¹⁸ This was calculated as $(0.41/0.35)^{(1/7)} - 1$. Note that this baseline does not attempt to project a recent trend toward dry conversion in the industry. It is not clear how this trend will continue, and the relationship between dry conversion and beneficial use is not clear. At this time few CCR markets are supply-limited.

year by that time. Total CCR tonnage is predicted to rise to This includes all beneficial use applications tracked by the ACAA, including mine fill.

EXHIBITS-4. BASELINE PROJECTION OF BENEFICIAL USE, BY APPLICATION



Note: The beneficial use tonnages represented by the solid lines are measured on the left axis. The beneficial use rate represented by the dashed line is measured on the right axis.

S.3 Potential Impact of CCR Final Rule on CCR Beneficial Use

The final rule may lead to three specific impacts related to the beneficial use of CCRs:

1. **Increased CCR beneficial use due to increased disposal costs.** The increase in CCR disposal costs associated with the rule will provide an incentive for coal-fired power plants to seek alternative methods of managing their CCR.
2. **Reduced CCR beneficial use associated with restrictions on some beneficial uses.** Restrictions on specific beneficial use applications enumerated in the final rule may lead to a reduction in beneficial use.
3. **For Subtitle C option, reduced CCR beneficial use due to “stigma” effects.** The regulation of CCR as a RCRA hazardous waste when disposed may inhibit some facilities from beneficially using these materials.

Each of these potential effects is described in detail below.

S.3.1 Increased CCR Disposal Costs

Across multiple waste management contexts, high disposal costs are proven to create an economic incentive to increase the beneficial use of secondary materials. For example, according to data from EPA’s Biennial Report database, less than 10% of electric arc furnace

(EAF) dust was recycled prior to its regulation under RCRA Subtitle C, whereas the recycling rate for this material was well above 40% during the period 2000-2007. Given the increase in disposal costs associated with the final rule, the rule will likely incentivize coal-fired power plants to manage more of their CCRs through beneficial use. This would be consistent with the “avoided disposal cost incentive” referred to by ACAA under which power plants are willing to incur increased transportation costs to avoid higher disposal costs.¹⁹ The end result would be an increase in beneficial use, and a decrease in disposal, of CCRs. The incentive to minimize disposal costs is also documented in the peer-reviewed literature. For example, Franchetti (2011) found a statistically significant, negative relationship between the cost of disposal and the quantity of solid waste generation among U.S. manufacturers and the per-ton cost of waste disposal.²⁰

S.3.2 Restrictions on CCR Beneficial Use Applications

As mentioned in Chapter 2 of this RIA, the final rule clarifies EPA policy on the beneficial use of structural fill and some mining applications. Under this action, EPA considers CCRs to be beneficially used if they provide a functional benefit; replace the use of an alternative material, particularly in such a way that conserves natural resources that would otherwise need to be obtained through practices such as extraction; and meet relevant product specifications and regulatory standards, where these are available. Structural and flowable fill uses for CCRs that meet these criteria will be considered beneficial uses and will therefore be exempt from regulation under the Bevill exemption.

According to the ACAA’s annual CCR survey, engineered fills are typically constructed in layers of uniform thickness and compacted to a desired unit weight.²¹ These fills can be used for small and large scale engineering projects in a variety of different forms, all of which will continue to qualify as beneficial use. Certain fill applications for CCRs, however, more closely resemble landfills than structural fills with clear engineering purposes, particularly in the case of some sand and gravel pits. Under the final rule, EPA therefore treats as disposal some large-scale fill operations, particularly those involving sand and gravel that do not meet the appropriate engineering specifications and are closely akin to landfills. This may lead to a reduction in the beneficial use of CCRs.

Besides large-scale fill applications, the final rule does not address other mine-filling applications of CCRs. These uses may be addressed in a future regulatory action.

¹⁹ ACAA, Frequently Asked Questions,

<http://acaa.affiniscap.com/displaycommon.cfm?an=1&subarticlenbr=5#Q14>

²⁰ Matthew Franchetti, “ISO 14001 and solid waste generation rates in U.S. manufacturing organizations: an analysis of relationship,” *Journal of Cleaner Production*, Vol 19 (2011) 1104-1109.

²¹ James Roewer and Daniel E. Klein, “Estimating GHG Savings from Use of Coal Combustion Products: Methodology and Results for 2000-2001,” Utility Solid Waste Activities Group, available online at <http://www.uswag.org/ccpuse.pdf>.

S.3.3 Stigma Effect on CCR Beneficial Use (Subtitle C Option 1 Only)

Economic theory suggests that if this rule increases the cost of disposal, beneficial use options will become more economically attractive, providing an incentive for power plants to increase beneficial use and avoid the increased cost of CCR disposal. Based on this reasoning, the general economic impact of Regulatory Option 1 would be to increase beneficial use. This general economic relationship, however, may be complicated if potential users of CCR are concerned about the designation of CCR as a hazardous waste when disposed. As evidence of this potential complication, some industry and state government stakeholders expressed concern in response to the proposed CCR rule that designating CCR as a RCRA hazardous waste when disposed would stigmatize CCR. These stakeholders fear that, rather than provide an economic incentive to recycle, regulating CCRs under RCRA Subtitle C when disposed would increase the perceived risk associated with using the material and severely curtail the beneficial use of CCRs. Although the rule would maintain the Bevill exemption for recycled materials for CCRs directed to certain beneficial uses under Subtitle C or D, industry and state government stakeholders asserted in letters to EPA that this distinction will be too difficult to make. This uncertainty, stakeholders argue, will prompt buyers to choose alternatives to CCRs that have no hazardous stigma attached to them.

This section explores the concept of stigma, assesses the specific sources of stigma identified by stakeholders, and reviews the impacts of past rulemakings for evidence of a stigma effect.

S.3.3.1 What is stigma?

According to Muldowney and Harrison (1995), environmental stigma results from a perception of uncertainty and risk.²² Muldowney and Harrison apply this definition in the context of site clean-ups and the contamination of property. As noted by Kunreuther and Slovic (2001) and Fischhoff (2001), potential purchasers may be unwilling to consider a property when the perceived risks are greater than the actual risks, even in cases where technical information suggests that the benefits of clean-up outweigh the costs.²³ In addition, in the context of the CCR rule, the following definition of stigma posited by Gregory et al. (1996) captures the concerns expressed by various stakeholders:

*Stigma is: “something that is to be shunned or avoided not just because it is dangerous but because it overturns or destroys a positive condition signaling that what was or should be something good and acceptable is now marked as blemished or tainted.”*²⁴

²² T.J. Muldowney and K.W. Harrison (1995), “Stigma Damages: Property Damage and the Fear of Risk,” *Defense Counsel Journal* 62, pp. 525-538.

²³ Fischhoff, B. (2001), “Defining Stigma,” *Risk, Media, and Stigma*. Ed. James Flynn, Paul Slovic, and Howard Kunreuther. London: Earthscan Publications. 361-368; and Kunreuther, H. and Slovic, P. (2001), “Coping with Stigma: Challenges and Opportunities,” *Risk, Media, and Stigma*. Ed. James Flynn, Paul Slovic, and Howard Kunreuther. London: Earthscan Publications. 331-352.

²⁴ Gregory, R., P. Slavic and J. Flynn (1996), “Risk perceptions, stigma, and health policy,” *Health & Place* 2:4. Available online at [http://dx.doi.org/10.1016/1353-8292\(96\)00019-6](http://dx.doi.org/10.1016/1353-8292(96)00019-6).

Applying this definition to the CCR rule, the concerns expressed by some stakeholders imply that a Subtitle C designation for CCR when disposed will, in effect, taint the material due to an inflated perception of risk. These stakeholders maintain that this perception of risk will drive former CCR purchasers to substitutes with no hazardous stigma, even if those substitutes are more expensive.

Expanding on this definition, Gregory et al. also identify five defining features of environmental stigma.²⁵

1. Its source is a hazard that is perceived to be highly risky;
2. It violates standards of fairness or what is natural;
3. Its impacts seem to be inequitably distributed (e.g. differentially affecting certain demographic groups, or certain locations);
4. The possible outcomes are scientifically uncertain or unbounded; and
5. The hazard appears to have been improperly managed.

Of these, high risk perception (1) and scientific uncertainty (4) are the most relevant to classifying CCR as a hazardous waste under RCRA Subtitle C.

S.3.3.2 How does stigma occur?

This RIA identifies four potential pathways through which the CCR rule may result in stigma effects that reduce beneficial use. These pathways include (1) state government regulatory prohibitions on the beneficial use of CCRs, (2) perceived liability risk for facilities that store or handle CCR, (3) reduced consumer demand for products containing CCRs, and (4) changes made by standard-setting organizations restricting CCR in specific applications.

State government prohibitions

Due to the potential stigma that may be attached to CCRs, some states may prohibit the beneficial use of CCRs if they are regulated as a RCRA hazardous waste when disposed. In addition, some stakeholders have suggested that existing regulations in some states expressly prohibits the beneficial use of CCRs if they are classified as a hazardous waste under RCRA Subtitle C. In particular, the ACAA's public comment on the proposed CCR rule asserts that at least 14 states will restrict the beneficial use of CCRs if they are regulated under Subtitle C when disposed.²⁶ These states include Colorado, Delaware, Florida, Georgia, Maryland, Michigan, Montana, North Carolina, North Dakota, Pennsylvania, Tennessee, Texas, Virginia, and Wyoming. The ACAA's comment suggests that CCR beneficial use of all types may cease in these states if CCR is a Subtitle C waste when disposed and if state regulations are not changed.

To assess the ACAA's claims, EPA reviewed the regulations of all 14 states identified by ACAA. This review found that the 14 states identified by ACAA do not have any regulations that distinguish them as a group from the other 36 states regarding beneficial use of hazardous

²⁵ *Ibid.*

²⁶ Comments from American Coal Ash Association, November 18, 2010. EPA-HQ-RCRA-2009-0640-6202

materials. Several of the states identified by ACAA adopt by reference the federal regulation that exempts CCRs from classification as a hazardous waste, including Georgia, North Carolina, Texas, Virginia, and Wyoming. In addition, the states of Colorado, Maryland, Montana, Texas, Virginia, and Wyoming have enacted statutes that either prohibit them from adopting standards more stringent than federal regulations or require them to take legislative action to enact standards more stringent than federal regulations. This suggests that, under current state law, the beneficial use of CCR would not be prohibited in these states if CCR were a RCRA hazardous waste when disposed but not when beneficially used. Of the states listed by the ACAA, only the state of Georgia submitted a public comment to EPA suggesting that it may prohibit any CCR beneficial use applications if CCRs are classified as a hazardous waste when disposed. In addition, the Alabama Department of Transportation indicated that it would stop using concrete made with coal ash if CCR is designated as hazardous with disposed, although the Department did not specify whether it intends to forgo Federal funds if it violates the Comprehensive Procurement Guidelines.²⁷ Other states may institute similar prohibitions, but most states include discretionary clauses in their beneficial use regulations that make it difficult to predict a complete ban on the beneficial use of CCR.²⁸

Liability Risk

One potential concern associated with designating CCR as a hazardous waste when disposed is that the beneficial use of CCR would decline due to liability concerns. Similarly, some stakeholders have suggested that insurers would either increase premiums for facilities that use CCRs or exclude incidents related to CCR beneficial use from facilities' insurance policies.

This RIA does not anticipate that these liability and insurance issues will cause measurable changes in beneficial use, as these same concerns apply in the baseline. Under current law, if the beneficial use of CCR results in the release of hazardous contaminants that impact public health and/or the environment, Superfund liability may be attached to the beneficial use site. For example, the beneficial use of fly ash on the Battlefield Golf Club in Chesapeake, Virginia led to concerns about the potential contamination of local water wells. Although EPA testing determined that water wells were not impacted by the use of fly ash on the golf course, EPA tested the wells for the expressed purpose of determining whether contamination levels supported listing the golf course on the National Priorities List (NPS).²⁹ Because Superfund liability for this and other sites may apply in the baseline, insurance premiums and policies for facilities that use CCRs are also likely to reflect this liability in the baseline. Therefore, these liability issues do not represent an incremental impact of designating CCR as a hazardous waste when disposed. It is possible, however, that characterization of CCR as hazardous when disposed may create the *perception* of increased liability risk.

²⁷ See "Three Alabama agencies back coal ash as nonhazardous," *The Daily Times*, May 17, 2011, http://www.thedailytimes.com/Business_News/story/Three-Alabama-agencies-back-coal-ash-as-nonhazardous-id-011476.

²⁸ See summary information on state beneficial use regulations at U.S. DOE, National Energy Technology Laboratory, "IEP – Coal Utilization By-Products: Current Regulations Governing Coal Combustion By-Products – State Links," available at http://www.netl.doe.gov/technologies/coalpower/ewr/coal_utilization_byproducts/states/select_state.html.

²⁹ See U.S. EPA, "Battlefield Golf Club Community Update," April 2010, http://www.epa.gov/reg3hwmd/CurrentIssues/finalr-battlefield_golf_club_site/index.html.

Consumer demand

The stigma impact of the rule may also manifest itself in the form of reduced CCR demand among current users of these materials. A Subtitle C designation for CCRs, when they are disposed, may increase the perceived risk associated with these materials, causing some current users to seek substitutes.³⁰ While some users may change practices away from beneficial uses, others may seek cost savings associated with the options. EPA's past experience suggests, that, in total, a "hazardous" designation for industrial secondary materials and wastes does not impose a significant barrier to their beneficial reuse. Rather, non-regulated uses generally increase as the costs of regulated disposal increase. The examples in Exhibit S-5 illustrate the point that a RCRA "hazardous waste" designation does not necessarily impede a material's subsequent industrial recycling or reuse as a raw or intermediate material.

EXHIBIT S-5. PAST BENEFICIAL USE OF OTHER RCRA HAZARDOUS WASTE

HAZARDOUS WASTE ^a	POTENTIAL BENEFICIAL USES	EVIDENCE OF STIGMA
Electric arc furnace dust (RCRA waste code K061)	Electric arc furnace dust can be reused in fertilizer, steel production, and the manufacture of zinc products, including pharmaceutical materials. Slag from the smelting of electric arc furnace dust is also in high demand for use in road construction.	Prior to its regulation under RCRA, less than 10% of electric arc furnace dust waste was being recycled. ^b Recently, in the period 2000-2007, approximately 42% to 51% was beneficially reused.
Electroplating wastewater sludge (F006)	Electroplating wastewater sludge can be recycled for its copper, zinc, and nickel content for use in the commercial market.	In 2007, 35% (37,857 tons) of electroplating wastewater sludge was recycled. ^b
Chat	Chat originates in Superfund cleanup waste with lead contamination, and can be recycled for use in road construction.	While chat is clearly a hazardous waste, given its Superfund origins, it continues to be reused regardless of stigma.
Spent solvents	Spent solvents are generated from the washing of metal parts, and can be used in the production of roofing shingles.	Despite use in residential homes, no stigma appears to exist for roofing shingles.
Spent etchants	Spent etchants can be directly used as ingredients in the production of a copper micronutrient for commercial livestock.	The use of etchants to create micronutrients was approved by the FDA, and do not appear to have caused any kind of stigma effect. ^c
Sources: ^a All information is from the following source unless otherwise indicated: U.S. EPA, "Regulatory Impact Analysis for EPA's Proposed RCRA Regulation of Coal Combustion Residues (CCR) Generated by the Electric Utility Industry," June 2010. ^b Testimony of Lisa Evans, Senior Administrative Counsel, Earthjustice, before the Subcommittee on Energy and Environment, Committee on Energy and Commerce, U.S. House of Representatives April 14, 2011; ^c Heritage Environmental Services, LLC, "Micronutrients: About" at http://micronutrients.net/about/history/		

³⁰ For example, a poll included in Waste Management's comment on the proposed rule showed that consumers expressed significant concern about the beneficial use of coal ash in bricks and cement when told that this material is hazardous. The questions in the poll, however, did not provide respondents with any information on risk. If such information had been provided, respondents' answers may have been more positive. See Waste Management, comments submitted to EPA in response to the proposed CCR rule, docket document ID no. EPA-HQ-RCRA-2009-0640-8846, 2010.

Changes in product standards:

To facilitate consistency in product characteristics, organizations such as ASTM develop standards that detail the technical specifications of several products. In particular, ASTM developed and maintains technical standards for concrete that specify the maximum amount of fly ash recommended for use as cementitious material in concrete. Following publication of the proposed CCR rule, stakeholders expressed concern that designation of CCR as a RCRA hazardous waste when disposed would result in ASTM's removal of fly ash from its technical standard for concrete. This would lead to a significant reduction in the beneficial use of fly ash in concrete applications. In a letter submitted to the CCR rule docket, however, ASTM clarified that the organization never asserted that it would remove fly ash from its concrete standard if fly ash were a hazardous waste when disposed.³¹ Based on the ASTM letter, this RIA does not assume that standard setting organizations will remove CCRs from their technical standards if these materials are designated as a hazardous waste under RCRA when disposed.

The ACAA notes that in each of the cases highlighted in Exhibit S-5 above, the waste streams are significantly smaller than CCR waste streams.³² Consumers, however, continue to use many materials in large quantities that are classified as "hazardous" materials under RCRA, such as motor oil. Other products, including gasoline, common drain and household cleaners, cathode ray tube monitors, many fluorescent lamps, dental amalgam, many pharmaceuticals, and nicotine gum, are all hazardous wastes if disposed. Consumers have also proven comfortable with many recycled hazardous wastes; much of the mercury used in the U.S. comes from discarded mercury or mercury products that are labeled hazardous, such as fluorescent lamps and CFLs. A regulatory status as "hazardous waste" does not discourage the use of these products. Furthermore, as a result of the ACAA's efforts, consumers are well educated about the safety of CCRs when beneficially used.

S.3.3.3 How likely is stigma to damage the market for CCRs?

To accurately assess and quantify the likely effects of stigma on the beneficial use markets for CCRs, this RIA would ideally rely upon detailed survey data characterizing the preferences of CCR purchasers. Instead, the available information consists almost exclusively of anecdotal data and stakeholder comments.³³ In the absence of detailed data, this analysis employs a general

³¹ "Hazardous Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities Docket," memorandum from James A. Thomas, ASTM, to EPA docket EPA-HQ-RCRA-2009-0640, June 26, 2010.

³² ACAA, Comments to Hazardous and Solid Waste Management System; Identification and Listing of Special Waste; Disposal of Coal Combustion Residuals from Electric Utilities (Docket ID: EPA-HQ-RCRA-2009-0640), p101.

³³ For example, as outlined above, ACAA claims that stigma will reduce beneficial use. Comments from Earth Justice, the Center for Progressive Reform, and the Sierra Club suggest that a hazardous waste designation would not stigmatize CCR and reduce beneficial use but will instead increase the cost of disposal, inducing power plants to manage more of their CCR through beneficial use. See Appendix A to Earth Justice comment, prepared by Frank Ackerman & Elizabeth Stanton, senior economists, Stockholm Environmental Institute, November 20, 2010, docket document ID no. EPA-HQ-RCRA-2009-0640-6311.1; Center for Progressive Reform (CPR), prepared by Rena Steinzor, Professor, University of Maryland Law School and Michael Patoka, Law Clerk, University of Maryland Law School, November 19, 2010, docket document ID no. EPA-HQ-RCRA-2009-0640-8847; and Strategic

“Weight of Evidence” (WOE) methodology to assess the potential stigma impacts of the rule on CCR beneficial use. In the context of risk assessment, the formal concept of “Weight of evidence” typically refers either to established interpretative methodologies (e.g., systematic narrative review, meta-analysis, etc.) or to claims about risk that emerge from their use. Any risk assessment involves a combination of scientific evidence and interpretive methods; WOE represents the latter.³⁴

As described above, the available information suggests that liability concerns are unlikely to affect beneficial use relative to the baseline, as liability is attached to CCR under the baseline and under the final rule. Similarly, input offered by standard setting organizations on this rule do not suggest that CCRs will be removed from the ASTM or other standards for concrete or other products that may use CCRs. Thus, any stigma effect associated with the rule will hinge largely on state regulation of beneficial use and the demand response of CCR consumers. Stigma effects associated with these factors will not necessarily be uniform. The perceived risk of beneficial use may vary by beneficial use application and, for a given application, across different types of CCR consumers. In addition, the factors that influence beneficial use decisions may differ across different CCR users.

Regulatory Option 1 is unlikely to result in significant stigma-related impacts. This would be consistent with the historical beneficial use of hazardous materials, as documented in Fortuna (2010).³⁵ In addition, because many of the users of CCRs are sophisticated organizations with a firm understanding of the minimal risks associated with using this material, they are likely to continue using it regardless of whether the rule designates it as a hazardous waste when disposed. Consumers’ current use of various materials that are considered hazardous waste when disposed provides further support to the conclusion that the rule’s stigma impacts will be minimal. Nevertheless, to ensure that the RIA does not overestimate any positive beneficial use impacts that may result from Regulatory Option 1, this analysis employs the following conservative assumptions with respect to stigma for each of the major beneficial use applications:

- **Fly ash use in concrete.** The use of fly ash in concrete production is unlikely to be significantly affected by stigma effects. Much of the concrete containing fly ash is used in federally funded construction projects, per the requirements of the Comprehensive Procurement Guidelines (CPG). To ensure the continued receipt of federal funds for construction projects, states are unlikely to deviate significantly from the CPG. In addition, because fly ash is typically less expensive than cement, state prohibitions against the use of fly ash in concrete would increase the costs incurred by states for major construction projects, exacerbating the budget challenges that they face in the current economic downturn. Moreover, the state agencies that purchase much of the fly ash-containing concrete are sophisticated users of this product who understand that the risks

Environmental Analysis, L.C. prepared for the Sierra Club, Earth Justice, Natural Resources Defense Council, November 20, 2010, docket document ID no. EPA-HQ-RCRA-2009-0640-9634.1.

³⁴ For a more complete discussion of the literature on Weight of Evidence, see Douglas L. Weed, “Weight of Evidence: A Review of Concept and Methods” (*Risk Analysis*, Vol. 25, No. 6, 2005).

³⁵ Richard C. Fortuna, *Recycling of Hazardous Waste: RCRA’s Unsung Success Story*, prepared for Sierra Club, Earth Justice, and Natural Resources Defense Council, November 20, 2010. This document highlights the growth in the recycling and use of numerous hazardous materials, such as used oil, saccharin, lead acid batteries, petroleum refining sludge, and electric arc furnace dust.

associated with encapsulated uses are minimal, particularly for highway and bridge construction. For all of these reasons, this RIA assumes no stigma effects related to the beneficial use of fly ash in concrete.

- **FGD gypsum used in wallboard.** Buyers of recycled gypsum (wallboard producers) are sophisticated customers who have made significant investments in their plants in order to use recycled, FGD gypsum rather than mined virgin gypsum as their primary feedstock. States may therefore be reluctant to prohibit the beneficial use of FGD gypsum at these facilities. In addition, because wallboard is an encapsulated use of FGD gypsum, sophisticated consumers (end users) will understand that the risk associated with using wallboard containing FGD gypsum is likely to be negligible. An indeterminate number of homeowners and other consumers, however, may perceive a heightened sense of risk associated with the beneficial use of this material and opt for wallboard constructed of virgin gypsum. Thus, there may be a minor stigma effect for FGD gypsum currently used in the production of wallboard purchased directly by households.
- **CCR used as fill.** Unlike fly ash used in concrete and FGD gypsum used in wallboard, fill applications of CCRs are not an encapsulated use. The perceived risk for fill applications may therefore exceed that for these other uses. This perceived risk may vary by fill application. For structural fills that have little contact with residential property, such as embankments along highways, the perceived risk is unlikely to be great, whereas the perceived risk associated with using CCR as fill on residential property would likely be more significant. In addition, because the use of CCR in fill is not covered by the CPG, the financial incentive for states to allow the use of CCR as fill in construction projects is not as great as the incentive to use concrete that contains CCR. CCR, however, would still be a less costly fill material in many areas. Considering these factors, there may be a stigma effect for fill used in residential applications.

S.4 Estimation of Potential Impact of the CCR Final Rule on Beneficial Use

This section presents a quantitative assessment of the potential impacts of the CCR final rule on beneficial use. As described in further detail below, this analysis considers three factors that may influence beneficial use:

- (1) Incentive to avoid increased disposal costs,
- (2) Beneficial use restrictions included in the final rule, and
- (3) Potential stigma effects associated with classifying CCR as a hazardous waste when disposed (Subtitle C Option 1 only).

This appendix evaluates potential impacts on three specific CCR beneficial use applications:

- Fly ash as a substitute for portland cement in concrete production,
- FGD gypsum as a substitute for virgin gypsum in wallboard production, and
- CCR use in fill applications not prohibited by the final rule.

The analysis of the rule's beneficial use impacts, as presented below, differs in several important ways from the analysis in the proposed rule RIA. The analysis presented here was designed to yield central estimates of the rule's beneficial use impacts, whereas the 2010 RIA used bounding analyses to assess potential beneficial use impacts under lower- and upper-bound scenarios. The upper bound scenario in the 2010 RIA accounted for the economic incentive to avoid increased CCR disposal costs through the beneficial use of CCRs but did not include any stigma effects, while the lower bound scenario reflected stigma but not the economic incentive to increase beneficial use rather than incur higher disposal costs. This RIA integrates these two approaches by simultaneously examining both of these effects. Another important difference is that the 2010 RIA used a different approach for projecting beneficial use in the baseline that implicitly assumed the development of technological advances that would expand the use of CCRs in existing or new applications. As presented in Section S.2 above, the baseline in this RIA assumes that beneficial use technologies are mature and that annual increases in the beneficial use rate will be fairly gradual reflecting the same annual rate of increase over the next couple of decades as over the past decade.

S.4.1 Methods for Assessment of Beneficial Use Impacts

This RIA uses a linear-programming (LP) approach to estimate the changes in CCR beneficial use associated with the final rule. For each ton of CCR generated by a coal-fired power plant, the analysis determines whether beneficial use or disposal is the most economical management option, based on both the benefits and costs of beneficial use. For CCRs such as fly ash that may be used in multiple beneficial use applications, the analysis considers the relative costs and benefits of each beneficial use option and chooses the most economical of these options. In addition, the LP methodology accounts for regional capacity constraints for different beneficial use applications. For example, although much of the CCR available for beneficial use is generated by coal-fired power plants in the Midwest, concrete producers and other potential users of CCR in this region have limited capacity to use CCR, relative to the amount of CCR available in this region. Some of this CCR must therefore be shipped to other regions if it is to be beneficially used. To capture regional capacity constraints, this RIA estimates maximum CCR demand at the county or plant (for wallboard applications only) level.

The components of the beneficial use analysis are as follows:

1. ***Specification of CCR Generation Available for Beneficial Use.*** To assess the rule's beneficial use impacts, this analysis uses the projection of CCR generation described in Chapter 2. While this projection reflects *all* CCR generated by coal-fired power plants in the U.S., CCR that is wet handled is not suitable for beneficial use. In other words, CCR must be dry handled in order to be managed through beneficial use. To distinguish between wet handled and dry handled CCR, this RIA assumes that all CCR disposed in surface impoundments, as indicated in the EIA-923 database, is wet handled and that all other CCR is dry handled. The baseline projection of CCR generation assumes that the distribution between wet handled and dry handled CCR remains constant based on the distribution derived from the EIA-923 data for 2009, the most recent year for which data were available at the time of this analysis. The analysis does not

attempt to adjust baseline EIA projections to reflect continuation of the recent trend toward dry handling, but the regulatory impacts consider incremental changes in wet handling due to the rule.

For the regulatory options examined in this RIA, the amount of CCR available for beneficial use differs from the baseline projection due to surface impoundment closures in these scenarios. Under Regulatory Option 1, surface impoundments close by 2018, which will result in conversions from wet to dry handling systems. In addition, power plants must close or retrofit surface impoundments by 2020 under Regulatory Option 2, although the regulatory cost analysis in Chapter 4 of this RIA suggests that closure is the less costly option for most impoundments. To capture these requirements for Regulatory Options 1 and 2, this RIA assumes that all CCR that is wet handled in the baseline is dry handled in 2020 and thereafter and is available for beneficial use. This leads to a significant increase in CCR quantities available for beneficial use in 2020 under these scenarios.

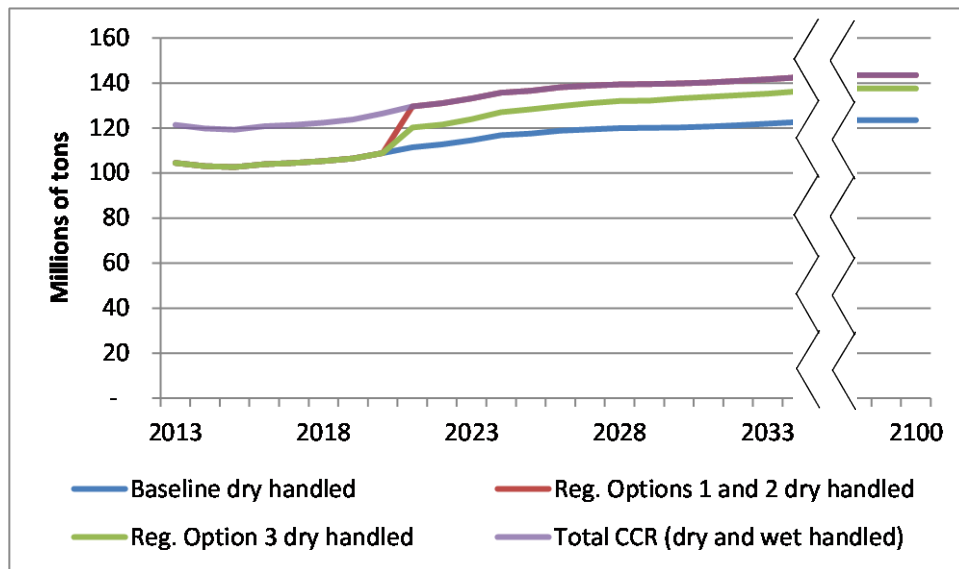
Regulatory Option 3 does not require closure or retrofit of *existing* impoundments, but does include more stringent design standards for new units. The cost analysis presented in Chapter 4 finds that offsite disposal under Regulatory Option 3 is less costly than building new impoundments. Therefore, similar to Regulatory Options 1 and 2, Regulatory Option 3 will result in a transition from wet-handling to dry-handling for CCR managed in impoundments in the baseline, increasing the tonnage of CCR available for beneficial use. This will occur as existing impoundments close. For the purposes of assessing beneficial use impacts, these closures are assumed to commence in 2020.

Exhibit S-6 shows the total tonnage of CCR generated over this RIA's analytic time horizon as well as the amount available for beneficial use in the baseline and under each of the regulatory options.³⁶

2. ***Projection of Baseline Beneficial Use.*** The analysis of beneficial use impacts relies upon the baseline projection of beneficial use for concrete, wallboard, and fill applications presented earlier in this appendix.

³⁶ Note that the amount of CCR generation through the 2010s in Exhibit QQQ-6 is slightly lower than the 130 million ton value reported above for the year 2010. This inconsistency reflects differences in data sources used for the projection and the historical 2010 estimate. For the projection, this RIA scales plant-level estimates of CCR generation from DOE's EIA-923 data based on projections of coal-fired electricity generation in EIA's Annual Energy Outlook (AEO) 2011. The 2009 EIA data show CCR generation of approximately 121 million tons, and AEO 2011 shows coal-based generation declining or remaining flat through much of the 2010s. Thus, this RIA projects relatively flat CCR generation through the 2010s as well. In contrast, the ACAA data referenced above suggest an increase in CCR generation in 2010, inconsistent with the trend in coal-based electricity generation shown in AEO 2011. This relies on the AEO data for the purposes of projecting CCR generation because they account for changes in coal-fired electricity generation over time.

EXHIBIT S-6. TOTAL CCR GENERATION AND PORTION OF CCR GENERATION AVAILABLE FOR BENEFICIAL USE, BY REGULATORY OPTION



Note: Only dry handled CCR may be beneficially used.

3. **Specification of Beneficial Use Restrictions:** As indicated above, the regulatory options analyzed in this RIA consider some large-scale fill operations to be disposal, particularly those involving sand and gravel that do not meet the appropriate engineering specifications and are closely akin to landfills. This RIA estimates that approximately 16% of the CCR beneficially used in fill applications in the baseline is used in large-scale fill applications (see **Appendix V** of this RIA). This figure was factored into the calculation of maximum CCR demand for fill applications, as described under item 5 below.
4. **Stigma:** This quantitative assessment of the CCR rule's beneficial use impacts assumes no stigma effects for Regulatory Options 2 and 3 and reflects the overarching conclusions with respect to stigma presented above in section S.3.3 for Regulatory Option 1. For the use of fly ash in concrete production, this RIA assumes no stigma effects under the Subtitle C option based on the weight of evidence presented above.

For both wallboard and fill applications stigma is more likely. Because some wallboard is purchased directly by households and some homeowners may perceive heightened risk associated with wallboard containing FGD gypsum, this analysis assumes some stigma effects for wallboard used in residential applications. Based on Census data for the value of residential and non-residential construction, this RIA assumes that 44% of wallboard is used for residential construction and renovation.³⁷ The Subtitle C option, however, is

³⁷ U.S. Census, Value of Construction Put in Place Survey, <http://www.census.gov/const/C30/prexcel.html>. The 44 percent estimate is the weighted average for the years 2003 through 2011; over this nine-year period, residential buildings accounted for approximately 44 percent of the total residential and non-residential construction value.

unlikely to stigmatize all residential wallboard containing FGD gypsum. Because FGD gypsum is encapsulated when used in wallboard, many homeowners may perceive no increase in risk under the Subtitle C option. Considering these factors, the precise magnitude of the stigma effect for FGD gypsum used in residential wallboard is uncertain. To approximate this stigma effect, this RIA assumes that wallboard plants located in the 14 states that ACAA identified for reductions in beneficial use will not use FGD gypsum for residential wallboard applications (i.e., they will use FGD gypsum only for non-residential wallboard).³⁸ Data from the *Global Gypsum Directory* and from a representative of the Gypsum Association suggest that wallboard plants in the 14 states identified by ACAA account for approximately 46% of the production capacity of wallboard plants capable of using FGD gypsum.³⁹

Stigma effects for fill applications are likely to be more significant than for FGD gypsum due to the fact that CCR is not encapsulated in fill. As described above, stigma is likely to be more significant for residential fill applications than non-residential applications. This analysis therefore assumes that stigma will eliminate all residential applications of fill but will have no effect on non-residential fill. Based on the Census data referenced above, the analysis further assumes that 44% of fill is used in residential applications.

Given the limited information available on CCR-related stigma, the stigma assumptions outlined above for wallboard and fill are relatively conservative (i.e., likely lead to overestimation of stigma-induced reductions in beneficial use). Despite the ACAA's assertion that 14 states will prohibit the beneficial use of CCR under Regulatory Option 1, regulations in these states do not support this claim. In addition, while stigma may prevent CCRs from being used as fill in some residential projects, this RIA has identified no information suggesting that stigma would prevent the use of CCRs in *all* residential fill projects.

5. **Potential Demand:** Assessment of the rule's beneficial use impacts also requires estimation of the potential demand for CCRs in beneficial use applications. Increased disposal costs may shift CCRs from disposal to beneficial use under the rule, but such shifts are constrained by demand for concrete and fill and the production capacity of wallboard plants equipped to use FGD gypsum.⁴⁰ This

³⁸ Although wallboard plants may not know whether a specific sheet of wallboard will be used in a residential or non-residential application, the assumption presented here merely implies that wallboard plants will use FGD gypsum in proportion to the percentage of wallboard likely to be used in non-residential applications.

³⁹ PRO Publications, *Global Gypsum Directory 2008-2009*, 2008 and Michael Gardiner. Gypsum Association. Personal communication, January 19, 2010. The Global Gypsum Directory includes production capacity data for each plant in the U.S., and Gardiner provided the estimated recycled content of wallboard plant input. Based on this information, it was possible to estimate the capacity of individual plants to produce wallboard based on FGD gypsum.

⁴⁰ This RIA assumes that only those wallboard plants currently equipped to use FGD gypsum may use FGD gypsum during the full 100-year time horizon of the analysis. To the extent that more wallboard plants convert to FGD gypsum over time, we may underestimate maximum demand for FGD gypsum. Based on personal communication with Charlie Poandl of LaFarge, the cost of retrofitting a wallboard plant to use FGD gypsum is approximately \$30-\$40 million (January 28, 2010).

RIA therefore estimates the potential demand for CCR in each beneficial use application. These values represent the maximum amount of CCR that may be used for a beneficial use application, given the projected activity level for that application (e.g., concrete produced in a given year). These estimates also reflect the stigma assumptions outlined above and (in the case of fill) the prohibition on the use of CCR in large-scale fill applications under the rule. Because potential demand is not linked to the amount of CCR generated, it may exceed CCR generation. This RIA's approach for estimating potential demand for each beneficial use application is as follows:

Fly ash in concrete: To estimate potential demand for fly ash in concrete, this RIA assumes that cementitious material represents 12.5% of concrete and that fly ash makes up no more than 30% of this cementitious material.⁴¹ Thus, 0.0375 tons of fly ash may be in every ton of concrete (1 ton x 12.5% x 30%). Applying this value to the total tonnage of concrete produced in the U.S. in 2010 (398.5 million tons), the potential demand for fly ash in concrete was 14.9 million tons in 2010.⁴² To project potential demand beyond 2010 through 2035, this RIA assumes that concrete production will grow at the same rate as the construction industry, as projected by EIA's Annual Energy Outlook 2011.⁴³ This assumption is based on the fact concrete is primarily used in construction projects. Potential demand after 2035 is assumed to remain constant at potential demand in 2035. This is consistent with the assumption stated above that CCR generation after 2035 remains flat at 2035 levels. Equation S-2 summarizes this approach.

$$(\text{Equation S-2}) \mathbf{DMax}_{C,t} = [(P_{C,2010})(M)(F)] \times \left(\frac{K_t}{K_{2010}} \right)$$

Where $\mathbf{DMax}_{C,t}$ = Potential demand for CCR in concrete at time t ;

$P_{C,2010}$ = Production of concrete in 2010 (398.5 million tons);

M = Portion of concrete made up of cementitious material (12.5%);

F = Portion of cement in concrete that may be replaced by fly ash (30%);

⁴¹ The Portland Cement Association estimates that 10 to 15 percent of concrete is made up of cement. See Portland Cement Association, *Cement and Concrete Basics*, http://www.cement.org/basics/concretebasics_concretebasics.asp, access on February 29, 2012. The 30 percent figure for the replacement of cement with fly ash is from U.S. EPA, *Study on Increasing the Usage of Recovered Mineral Components in Federally Funded Projects Involving Procurement of Cement or Concrete to Address the Safe, Accountable, Flexible, Efficient Transportation Equity Act: A Legacy for Users*, Report to Congress, June 3, 2008, EPA530-R-08-007.

⁴² Estimate of U.S. concrete production from European Ready-Mix Concrete Organization (ERMCO), *Ready-Mixed Concrete Industry Statistics*, June, 2010, available at http://www.ermco.eu/documents/ermco-documents/ermco-statistics-2010_rev03.pdf.

⁴³ U.S. Energy Information Administration, *Annual Energy Outlook 2011*, April 2011, Table 33.

K_t = Construction industry output at time t , as projected in AEO 2011; and
 K_{2010} = Construction industry output in 2010, as reported in AEO 2011.

FGD gypsum in wallboard: Potential demand for FGD gypsum used in wallboard production depends, in part, on the productive capacity of those wallboard plants equipped to use FGD gypsum rather than virgin gypsum. Because FGD gypsum is processed differently than virgin gypsum (i.e., gypsum ore is ground whereas FGD gypsum is hammered), the equipment used for the processing of FGD gypsum differs from the equipment used for gypsum ore.⁴⁴ A plant originally designed to use virgin gypsum may substitute approximately 15% to 20% of this material with FGD gypsum with minimal investment, but would require more significant investment for substitution beyond this threshold.⁴⁵

This RIA's projection of potential demand for FGD gypsum assumes that only those gypsum plants that currently use FGD gypsum will do so in the future. Based on plant capacity data from the *Global Gypsum Directory* and beneficial use data provided by a representative from the Gypsum Association, this analysis estimates that the wallboard industry had capacity for the beneficial use of approximately 14.2 million tons of FGD gypsum in 2008.⁴⁶ This represents 29 percent of the total quantity of gypsum used by the industry that year. To forecast the maximum demand for FGD gypsum, this analysis assumes that the productive capacity of the wallboard sector and the industry's maximum demand for FGD gypsum will grow over time at the same rate as the construction sector, as projected by AEO 2011.

The estimation of potential FGD gypsum demand for Regulatory Option 1 also reflects the assumptions outlined above with respect to stigma. For those gypsum plants located in one of the 14 states identified by ACAA, this RIA constrains potential FGD gypsum demand to wallboard used in non-residential applications.

Equation S-3 below illustrates this RIA's approach for projecting potential FGD gypsum demand over the 100-year time horizon of the analysis.

$$(\text{Equation S-3}) \mathbf{DMax}_{w,t} = \sum_p \mathbf{dmax}_{w,2008} \left(\frac{K_t}{K_{2008}} \right) N$$

⁴⁴ Personal communication with Charles Poandl of Lafarge North American, January 28, 2010. Lafarge operates wallboard plants in Kentucky, Florida, and New York.

⁴⁵ Personal communication with Charles Poandl, *op cit*.

⁴⁶ PRO Publications, *Global Gypsum Directory 2008-2009*, 2008 and Michael Gardiner. Gypsum Association. Personal communication, January 19, 2010. The *Global Gypsum Directory* includes production capacity data for each plant in the U.S., and Gardiner provided the estimated recycled content of wallboard plant input, expressed as a fraction of total input. Applying the plant-level recycled content estimates to the plant-level capacity information from the *Global Gypsum Directory*, it was possible to estimate the total tonnage of FGD gypsum used by individual plants.

Where $DMax_{W,t}$ = Potential demand for FGD gypsum in wallboard applications at time t . Includes wallboard plants located in the 14 states identified by ACAA as well as plants in other states;

$dmax_{W,2008}$ = Potential demand for FGD gypsum in 2008 at wallboard plant p ;

K_t = Construction industry output at time t , as projected in AEO 2011;

K_{2008} = Construction industry output in 2008, as reported in AEO 2011; and

N = Percentage of construction value associated non-residential construction. This variable is included in the equation only under Regulatory Option 1 for those wallboard plants located in the 14 states identified by ACAA.

CCR Use in Fill Applications: This RIA's assessment of potential CCR demand for fill applications assumes that CCR could potentially replace virgin fill in any application. According to data from the USGS, approximately 190 million tons of sand and gravel were sold in the U.S. in 2009 for fill or fill-like applications.⁴⁷ This RIA assumes that this value represents the maximum CCR demand for fill applications in 2009 (i.e, the total amount of CCR that could have been used as fill). To project potential demand for future years, this RIA assumes that demand grows at the same rate as the construction sector, as projected by EIA's *Annual Energy Outlook 2011*. As noted above, however, restrictions on CCR use in large-scale fill applications will limit the potential demand for CCR as a fill material under all three regulatory options considered in this RIA, though not under the baseline. To account for potential stigma effects under Regulatory Option 1 (see discussion above), the potential demand estimate excludes the estimated 44% of potential demand associated with residential fill.⁴⁸ Equation S-4 below summarizes this RIA's approach for estimating potential demand for CCR use in fill applications.

$$\text{(Equation S-4)} \quad DMax_{F,t} = D_{F,2009} \left(\frac{K_t}{K_{2009}} \right) (1 - L)N$$

Where $DMax_{F,t}$ = Potential demand for fill in at time t .

$D_{F,2009}$ = Demand for fill in 2009;

K_t = Construction industry output at time t , as projected in AEO 2011;

⁴⁷ U.S. Geologic Survey, *2009 Minerals Yearbook: Sand and Gravel, Construction [Advanced Release]*, July 2011. Fill and fill-like applications include (1) concrete aggregates (including concrete sand), (2) asphaltic concrete aggregates and other bituminous mixtures, (3) road base and coverings, (4) fill, and (5) snow and ice control.

⁴⁸ U.S. Census, Value of Construction Put in Place Survey, <http://www.census.gov/const/C30/prexcel.html>. The 44 percent estimate is the weighted average for the years 2003 through 2011; over this nine-year period, residential construction accounted for approximately 44 percent of the total residential and non-residential construction value.

K_{2009} = Construction industry output in 2009, as reported in AEO 2011;
and

L = Percent of fill used in large-scale applications (16%);⁴⁹

N = Percentage of construction value associated non-residential construction. This variable is included in the equation only under Regulatory Option 1.

Exhibit S-7 presents this RIA's projections of maximum potential CCR demand for each of the major beneficial use categories. As indicated in the exhibit, the potential demand for CCR in fill applications drops significantly between the baseline and Regulatory Option 1. This reflects the rule's prohibition against using CCR in large-scale fill applications and this RIA's conservative assumptions regarding stigma impacts for CCR used in residential applications. Potential demand for CCR in fill applications also declines under Regulatory Options 2 and 3 but less significantly than under Regulatory Option 1. Regulatory options 2 and 3 reflect the prohibition against using CCR in large-scale fill applications but assume no stigma effects.

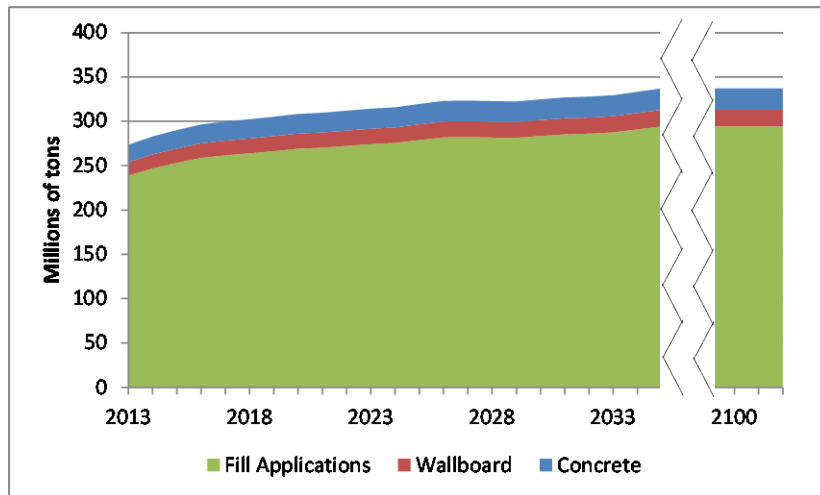
6. ***Geographic Distribution of Demand:*** As noted above, this RIA's assessment of the rule's beneficial use impacts accounts for differences in CCR demand across different regions. Because the transportation of CCR represents one of the most significant costs associated with beneficial use, information on the geographic distribution of CCR demand is essential to estimation of these costs. This information is also important for ensuring that the analysis does not assume, explicitly or implicitly, that the use of CCR in a given geographic area exceeds demand.

For both concrete and fill applications of CCR, precise information on the geographic distribution of demand is unavailable. In the absence of such information, this RIA assumes that the distribution of demand for these applications is consistent with the geographic distribution of the U.S. population at the county level, as reported for the 2010 Census. For FGD gypsum, this RIA assumes that demand is distributed to wallboard plants in proportion to their estimated capacity to use FGD gypsum, as estimated based on the approach outlined above for potential demand.

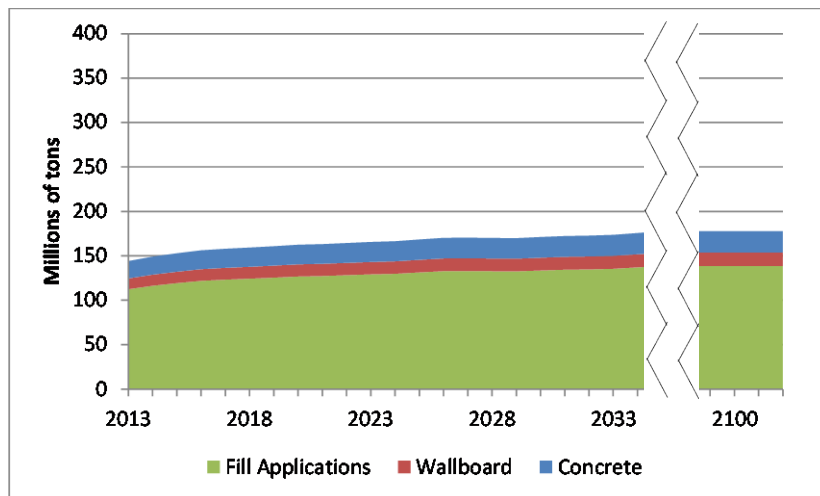
⁴⁹ Appendix V of this RIA documents the basis for this value.

EXHIBIT S-7. POTENTIAL CCR DEMAND, BY BENEFICIAL USE APPLICATION

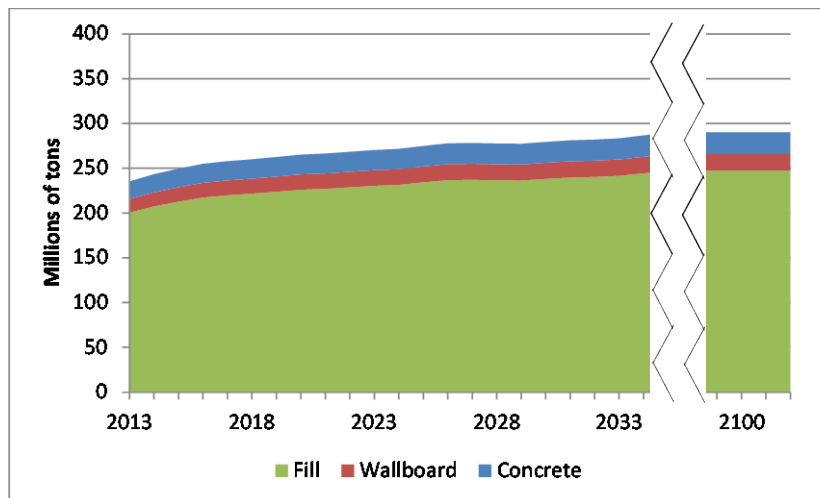
Baseline



Regulatory Option 1



Regulatory Options 2 and 3



7. ***Unit Costs and Benefits:*** For each ton of CCR available for beneficial use, this analysis considers the various benefits and costs of diverting the material from disposal to beneficial use. For all three beneficial use applications, the benefits to society of beneficial use include avoided disposal costs and the avoided cost of virgin materials (e.g., cement, virgin gypsum, and sand & gravel). As indicated in Exhibit S-8, this RIA estimates avoided virgin material costs based on prices reported by USGS. In addition, this RIA relies upon avoided disposal cost estimates derived from the cost analysis in Chapter 4. This RIA calculates avoided disposal costs, by year, on a per ton basis for each regulated power plant. The analysis does not assume that power plants would avoid the full compliance costs presented in Chapter 4 if they were to divert their CCR to beneficial use, as power plants would incur some of these costs, such as the costs of general liability insurance required under the rule, regardless of how they manage their CCR. For those power plants that would dispose their CCR offsite, the avoided cost of disposal includes avoided transportation costs. It is important to note that the cost analysis in Chapter 4 does not reflect the avoided CCR disposal costs associated with increased beneficial use. Thus, Chapter 4 overestimates costs for those regulatory scenarios under which beneficial use increases.

The costs of beneficial use include the transportation of CCR to a beneficial use site and processing costs that vary by beneficial use application. Based on data from the Bureau of Transportation Statistics, this RIA assumes that cost of transporting CCR is approximately \$0.16 per ton mile, as shown in Exhibit S-8. Application-specific beneficial use costs include the beneficiation of fly ash prior to use in concrete and de-watering costs for FGD gypsum prior to shipping the material to wallboard plants. Based on communications with an ACAA representative, this RIA assumes that approximately 13% of fly ash requires beneficiation prior to use in concrete.⁵⁰ With respect to de-watering, this RIA assumes that power plants that do not beneficially use any of their FGD gypsum in the baseline would incur both de-watering equipment costs and operation and maintenance (O&M) costs. In contrast, power plants that beneficially use a portion of their FGD gypsum in the baseline would incur O&M costs but not equipment costs associated with de-watering because we assume that such facilities already have de-watering equipment.

⁵⁰ Source: Personal communication with David Goss, ACAA, June 25, 2008.

EXHIBIT S-8. BENEFIT AND COST INPUTS FOR BENEFICIAL USE IMPACT ANALYSIS

Benefits of Beneficial Use	
Avoided Virgin Material Costs	Portland Cement: \$93.57 per ton ¹
	Gypsum Ore: \$7.50 per ton ²
	Virgin Fill: \$6.79 per ton ³
Avoided Disposal Costs	Vary by facility ⁴
Costs of Beneficial Use	
Transport of CCR: \$0.16 per ton mile ⁵	
Beneficiation (applies only to fly ash used in concrete): \$1.53 per ton ⁶	
Dewatering Capital (applies only to wallboard applications): Annualized cost of \$717,000 per power plant not equipped for de-watering, based on a 7 percent discount rate and 20-year lifespan. ⁷	
Dewatering O&M (applies only to wallboard applications): \$3.00 per ton of FGD gypsum de-watered ⁸	
Sources: - Hendrik G. van Oss, USGS, Mineral Commodity Summaries - Cement, January 2011. Estimate reflects average of values reported for 2006 through 2010. - Robert D. Crangle, Jr., USGS, Mineral Commodity Summaries - Gypsum, January 2011. Estimate reflects average of values reported for 2006 through 2010. - F Wallace P. Bolen, USGS, Mineral Commodity Summaries - Sand and Gravel (Construction), January 2011. Estimate reflects average of values reported for 2006 through 2010. - The cost per ton of CCR disposal was estimated by facility and year using the approach outlined in Chapter 4 of this RIA. - Bureau of Transportation Statistics, <i>National Transportation Statistics 2010</i>, Table 3-17: Average Freight Revenue Per Ton-mile. - According to ACAA's David Goss (personal communication, June 25, 2008), approximately 2 million of the 15 million tons of fly ash beneficially used in concrete in the U.S. (or 13.3%) undergoes beneficiation. In addition, based on the range of beneficiation costs presented in Electric Power Research Institute, <i>Beneficiation of Fly Ash Containing Mercury and Carbon</i>, this RIA estimates that a reasonable central tendency value for the cost of beneficiation is approximately \$10 per ton (in year 2004\$). The estimate of \$1.53 per ton presented in this exhibit reflects this \$10 estimate multiplied by the probability of fly ash requiring beneficiation (13.3%), scaled for inflation. - U.S. Department of Energy, National Energy Technology Laboratory, <i>Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity</i> DOE/NETL-2007/1281, August 2007. E. Cheri Miller, TVA, "Flue Gas Desulfurization (FGD) Gypsum Production, Processing, and Disposal," presentation. Undated.	

8. **Optimization:** Using the information and assumptions summarized above, the analysis used linear programming optimization methods to minimize the cost of CCR management for the U.S. as a whole. Consistent with the potential demand values described above, the LP constrains the optimization of costs to ensure that total shipments of each CCR to demand each location do not exceed the total available demand at that site for a given beneficial use application.

This RIA applied this optimization approach on an annual basis. Following this approach, some CCR is projected to be managed through beneficial use in concrete, wallboard, or fill for each scenario while the remainder is disposed. Based on the results generated from this approach, this RIA estimates the change in beneficial use (by beneficial use application) for each regulatory scenario as the difference between beneficial use under that scenario and beneficial use under the baseline. The attachment to this appendix includes additional information on the optimization methodology.

S.4.2 Estimated Potential Future Changes in CCR Beneficial Use

Based on the methods outlined above, this section presents the estimated beneficial use impacts of the regulatory options considered by EPA. Exhibit S-9 shows the estimated percentage change in beneficial use, by application and scenario.⁵¹ The exhibit also shows the percentage change in beneficial use across all applications in aggregate. As indicated in the exhibit, the projected changes in beneficial use differ significantly across regulatory options. Under Regulatory Option 1, this RIA projects a reduction in total beneficial use from the baseline, whereas beneficial use increases under Regulatory Options 2 and 3 for most of the analytic time horizon.⁵² The significant reduction under Regulatory Option 1 reflects the stigma effects associated with designating CCRs as hazardous waste when disposed under Regulatory Option 1, as well as the prohibition on large-scale fill applications that applies to all three options. As noted above, this RIA applies conservative assumptions regarding stigma (i.e., that stigma would eliminate residential fill applications of CCR and would limit the use of stigma in residential wallboard). Thus, the results in Exhibit S-9 may overestimate the reduction in beneficial use associated with Regulatory Option 1. Stigma does not apply to the other two regulatory options, as they do not include a hazardous waste designation for CCRs. The results in Exhibit S-9 also indicate that the overall increase in beneficial use is higher under Regulatory Option 2 than under Regulatory Option 3. Because the cost of disposing CCR is higher under the former than under the latter, Regulatory Option 2 provides a greater economic incentive sooner for power plants to divert their CCR to beneficial use than Regulatory Option 3. The increases in beneficial use are projected for Regulatory Options 2 and 3 despite the decline in potential CCR demand for fill applications under these options (and Regulatory Option 1). Potential demand for fill applications under these options is still high relative to CCR generation.

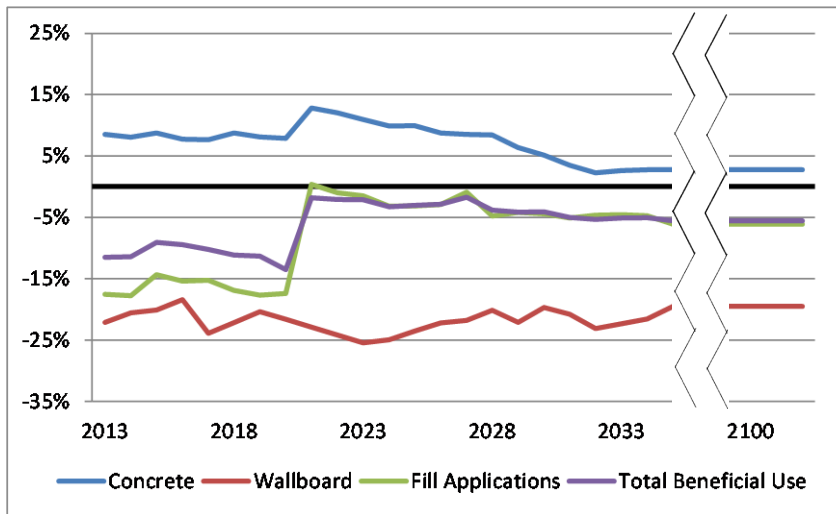
Across all three regulatory options, particularly Regulatory Options 1 and 2, beneficial use is projected to increase in 2020 relative to prior years. This is due to the increase in CCR available for beneficial use. As described above, a significant portion of CCR is wet-handled in the baseline and is therefore not available for beneficial use. Under Regulatory Options 1 and 2, this RIA expects that most, if not all, power plants that wet handle their CCR in the baseline will convert to dry handling in 2020 or shortly before. This will lead to an increase in the tonnage of CCR available for beneficial use in 2020 and, by extension, result in an increase in beneficial use in 2020 relative to prior years.

⁵¹ The exhibits presented in this section show constant beneficial use impacts from 2035 through 2112 because of this RIA's assumption that post-2035 beneficial use under the baseline and the regulatory scenarios remains constant at 2035 levels.

⁵² This result for Regulatory Option 1 largely reflects the conservative assumptions outlined above for stigma effects. If this option results in no stigma effects, this RIA projects an increase in beneficial use.

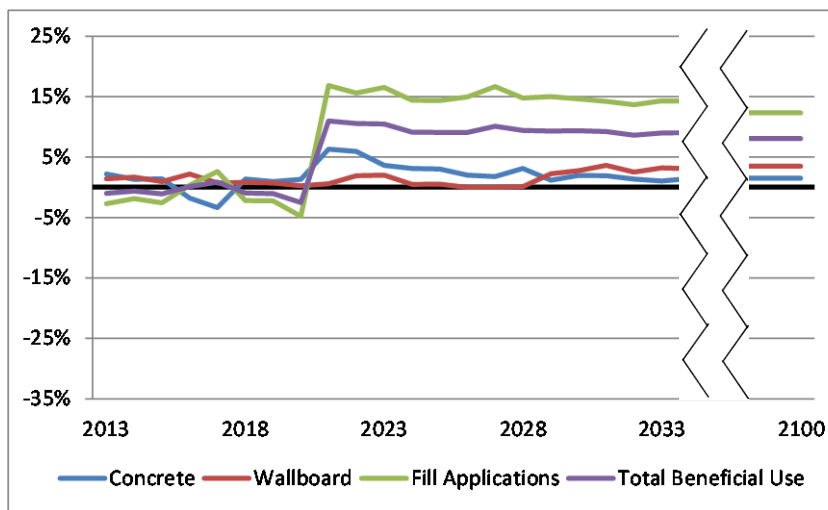
EXHIBIT S-9. PERCENTAGE CHANGE IN BENEFICIAL USE, BY APPLICATION

Regulatory Option 1 (Subtitle C Option)

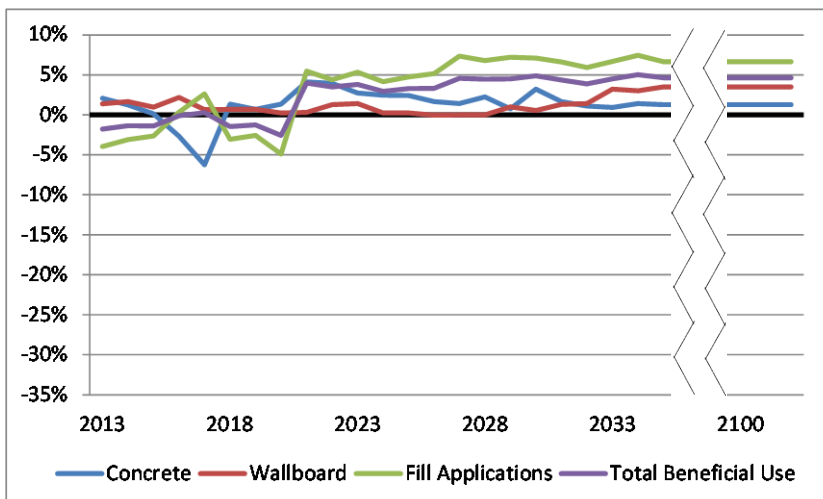


Note: The trend line for wallboard was smoothed for the 2020-2022 period to correct for outlier values generated by the baseline calibration described in the attachment to this appendix.

Regulatory Option 2 (Subtitle D Option)



Regulatory Option 3 (Subtitle D-Prime Option)



In addition to highlighting changes in beneficial use in aggregate, Exhibit S-9 above also highlights differences in beneficial use impacts between beneficial use applications. Under Regulatory Option 1, the beneficial use of CCR in fill and wallboard applications is projected to decline while the beneficial use of fly ash in concrete is projected to increase. The decline for fill and wallboard applications reflects the presumed stigma effects associated with this regulatory option. As described above, the weight of evidence suggests that there may be stigma effects under Regulatory Option 1 for residential fill applications and some residential wallboard applications, though the conservative assumptions applied here may overestimate these effects. In contrast, because the stigma associated with concrete applications is unlikely to be significant, the increase in disposal costs associated with Regulatory Option 1 creates an incentive for increased beneficial use of fly ash as a substitute for cement in concrete. The potential stigma associated with using fly ash in residential fill applications strengthens this incentive; some fly ash may be diverted from fill to concrete applications under this option.

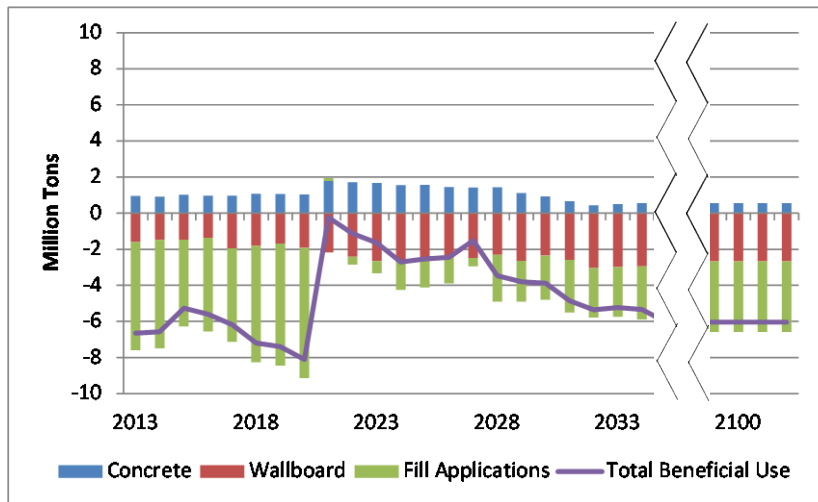
The differences in beneficial use impacts across applications are less pronounced under Regulatory Options 2 and 3. Under these options, the proportional increase in beneficial use is most significant for CCR use in fill applications, followed by fly ash in concrete and FGD gypsum in wallboard. The relatively large effect for fill applications reflects the vast potential for increased use of CCR in fill applications. As noted above, approximately 190 million tons of fill or fill-like materials were sold in the U.S. in 2010, whereas 130 million tons of CCR were generated that year (See Exhibit S-2 above). Due to this significant differential between potential demand and supply, capacity for CCR in fill applications is likely to be available in most areas. In contrast, power plants may need to transport CCR greater distances to increase beneficial use of in concrete and wallboard applications.

Complementing the percentage changes in beneficial use shown in Exhibit S-9, Exhibits S-10 and S-11 present the absolute change in beneficial use expected under each regulatory option. As indicated in the exhibits, fill applications account for the vast majority of the changes in beneficial use under all three regulatory options. Under Regulatory Option 1, fill accounts for most of the projected decline in beneficial use, due in large part to stigma impacts. Because the capacity to use CCR in fill applications is so high relative to other applications, fill also represents most of the increase in beneficial use under Regulatory Options 2 and 3. The results in Exhibit S-10 and S-11 also show that the beneficial use impacts of these two options change from negative to positive around the year 2020. This reflects the increase in CCR projected to become available for beneficial use around that time, as described above.

The beneficial use impact estimates presented in Exhibits S-9 through S-11 represent conservative estimates of these impacts for Regulatory Option 1. That is, the results presented in these exhibits likely overestimate the reduction in beneficial use under this option. As described above, this RIA estimates beneficial use impacts as if the stigma associated with designating CCR as a hazardous waste when disposed will preclude the beneficial use of CCR in *all* residential fill applications and in many residential wallboard applications. Although the weight of evidence suggests that stigma may preclude the use of CCR in some residential fill and wallboard applications, none of the available information indicates that these stigma effects are likely to be as significant as assumed in this analysis.

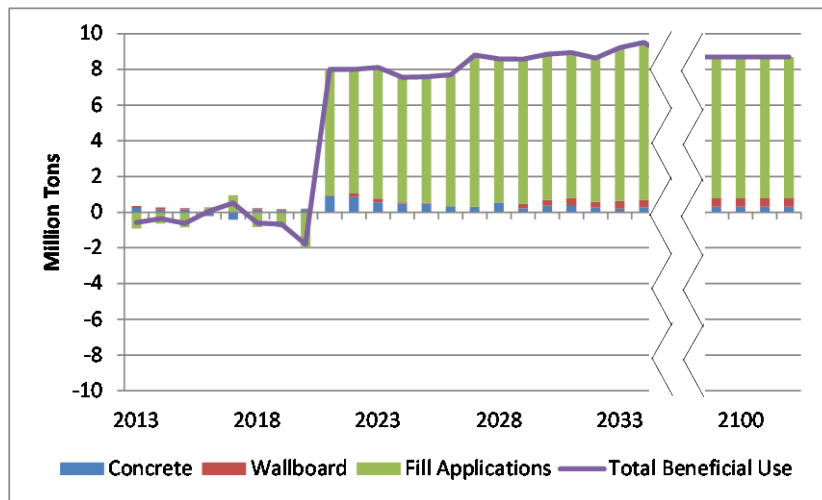
EXHIBIT S-10. ABSOLUTE CHANGE IN BENEFICIAL USE, BY APPLICATION

Regulatory Option 1 (Subtitle C Option)



Note: The trend line for wallboard was smoothed for the 2020-2022 period to correct for outlier values generated by the baseline calibration described in the attachment to this appendix.

Regulatory Option 2 (Subtitle D Option)



Regulatory Option 3 (Subtitle D-Prime)

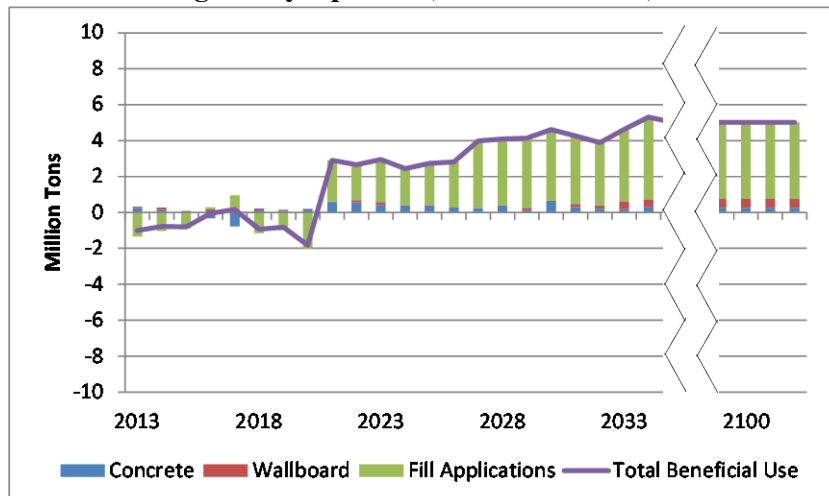


EXHIBIT S-11. 3-YEAR ROLLING AVERAGE OF THE ANNUAL CHANGE IN BENEFICIAL USE, BY OPTION AND APPLICATION (MILLIONS OF TONS)

YEAR	FLY ASH IN CONCRETE	FGD GYPSUM IN WALLBOARD	CCR IN FILL	TOTAL
<i>Regulatory Option 1 (Subtitle C Option)</i>				
2015	0.97	-1.44	-5.34	-5.81
2020	1.29	-2.81	-4.61	-6.12
2025	1.53	-2.58	-1.51	-2.57
2030	0.90	-2.53	-2.55	-4.18
2035-2112*	0.56	-2.67	-3.92	-6.03
<i>Regulatory Option 2 (Subtitle D Option)</i>				
2015	0.03	0.12	-0.46	-0.31
2020	0.39	0.05	1.40	1.84
2025	0.44	0.04	7.14	7.62
2030	0.30	0.35	8.13	8.79
2035-2112*	0.30	0.48	7.93	8.71
<i>Regulatory Option 3 (Subtitle D-Prime Option)</i>				
2015	-0.06	0.12	-0.61	-0.55
2020	0.28	0.04	-0.24	0.08
2025	0.35	0.02	2.30	2.67
2030	0.34	0.12	3.88	4.34
2035-2112*	0.26	0.48	4.28	5.02
Notes: <i>*Annual beneficial use impacts from 2036 through 2112 are assumed to be constant at 2035 levels.</i>				

S.5 Life Cycle Valuation of Potential Beneficial Use Impacts

This section presents the estimated value of the changes in beneficial use presented in the previous section. Based on life cycle inventory data for cement, sand and gravel, and raw gypsum (i.e., the materials displaced by CCRs), this RIA estimates the environmental impacts associated with changes in the use of CCRs as substitutes for virgin materials. These impacts include changes in energy consumption, water consumption, and air pollutant emissions. To estimate the monetary value of these impacts, this RIA uses values obtained from the empirical literature. The sections that follow include additional details on this approach and the results of the analysis.

The life cycle assessment does not itself represent a rigorous economic analysis, because it assumes a single linear change in production of materials as a result of a change in demand. It does not attempt to predict any behavioral responses (e.g., reduction in price, cost-saving approaches) that might also affect both projected changes in practice and the environmental impacts associated with those changes. However, consideration of life cycle impacts provides useful insights into the scale of “upstream” impacts associated with regulatory decisions about secondary materials, and may provide insights into the broader or unanticipated impacts associated with regulatory options.

An important assumption implicit in the results presented here is that using CCR in place of virgin materials saves 100% of the resource use from the virgin materials displaced. In addition, the results presented here reflect only the environmental impacts associated with the virgin materials displaced by CCR. They do not reflect the avoided emissions associated with CCR management in the baseline or any environmental impacts associated with beneficiation.

S.5.1 Life Cycle Data

To estimate the environmental impacts avoided from the beneficial use of CCRs, this RIA uses life cycle inventory data from the Ecoinvent database (v2.2) included in SimaPro version 7.2 and the National Renewable Laboratory's (NREL's) life cycle inventory database.⁵³ These databases include detailed information on the environmental impacts per unit (e.g., per ton) of a multitude of virgin materials, including those displaced by CCRs in concrete, fill, and wallboard applications. These impacts reflect environmental releases and resource consumption associated with the production of each material, as well as the upstream impacts associated with the extraction of raw materials used in production. In addition, because the SimaPro and NREL data do not reflect emissions controls required under EPA's 2010 national emission standards for hazardous air pollutants for the cement industry, this RIA relies upon air pollutant emission factors for the rule derived from EPA's regulatory impact analysis for the rule.⁵⁴ These values reflect emissions from cement production but not the upstream emissions associated with the production of inputs used in portland cement. By excluding these upstream emissions, this RIA underestimates the total life cycle emissions associated with portland cement and also underestimates the value (positive or negative) of changes in the use of fly ash as a substitute for portland cement in concrete production.

Exhibit S-12 below summarizes the life cycle inventory data for portland cement, sand and gravel, and raw gypsum ore used in this analysis. The values presented in the exhibit reflect the environmental impacts per ton of virgin material produced for each material. As indicated in the exhibit, impacts per ton of material produced are much higher for gypsum and portland cement than for fill. This reflects the more extensive processing required for gypsum and cement relative to fill. The data in the exhibit also show that a range of impact values was identified for energy use, water use, and greenhouse gas emissions associated with portland cement production. This RIA uses the midpoint of the reported ranges to assess the value of the beneficial use impacts associated with the final CCR rule.

⁵³ Swiss Center for Life Cycle Inventories, Ecoinvent Database v2.2, Dübendorf, CH, as included in SimaPro 7.2 LCA software, PRé Consultants, The Netherlands, and National Renewable Energy Laboratory's U.S. Life Cycle Inventory Database, <http://www.nrel.gov/lci/>. The Ecoinvent v2.2 data are based on European production processes for the industrial sector under the assumption that these processes are similar in the U.S. For the electric sector, however, Ecoinvent uses data for the U.S. grid.

⁵⁴ U.S. EPA, *Regulatory Impact Analysis: Amendments to the National Emission Standards for Hazardous Air Pollutants and New Source Performance Standards (NSPS) for the Portland Cement Manufacturing Industry Final Report*, August 2010.

EXHIBIT S-12. LIFE CYCLE IMPACTS PER TON OF MATERIAL PRODUCED

IMPACT CATEGORY		GYPSUM ¹	PORTLAND CEMENT ²	FILL ³
Energy (MMBtu)		1.29	3.52 - 3.62	0.04
Water (gal)		22,008	201 – 246,947	1,208
Air Emissions	Greenhouse gases (tons)	0.09	0.90 – 0.93	0.0032
	NO _x (tons)	1.47×10^{-4}	0.0019	2.68×10^{-5}
	PM _{2.5} (tons)	1.00×10^{-4}	1.24×10^{-5}	2.36×10^{-6}
	PM ₁₀ (tons)	4.70×10^{-4}	6.40×10^{-5} to 2.96×10^{-4}	1.52×10^{-7}
	SO _x (tons)	2.08×10^{-4}	2.43×10^{-4}	8.50×10^{-6}
	Hg (pounds)	$1.24\text{E} \times 10^{-6}$	4.02×10^{-5}	6.60×10^{-8}
	Pb (pounds)	6.06×10^{-5}	1.91×10^{-4}	4.83×10^{-7}
	CO (tons)	$2.96\text{E} \times 10^{-5}$	5.08×10^{-4} to 1.10×10^{-3}	7.00×10^{-6}
Notes: 1. Values for gypsum reflect data for stucco derived from Ecoinvent v2.2 as included in SimaPro 7.2. Stucco is the term used in SimaPro to describe the gypsum material used in wallboard. Avoided gypsum mining and avoided processing of gypsum into stucco, as represented by the Ecoinvent stucco manufacturing data set, are the only lifecycle stages modeled in SimaPro. 2. For energy use, water use, greenhouse gases, carbon monoxide, and PM₁₀ associated with portland cement, the range of values presented in this exhibit reflect data from Ecoinvent v2.2 as included in SimaPro 7.2 and the National Renewable Energy Laboratory's U.S. Life Cycle Inventory Database, the latter of which is available at http://www.nrel.gov/lci/. The Portland cement values for NO_x, PM_{2.5}, SO_x, and mercury were all derived from emissions data presented in U.S. EPA, Regulatory Impact Analysis: Amendments to the National Emission Standards for Hazardous Air Pollutants and New Source Performance Standards (NSPS) for the Portland Cement Manufacturing Industry Final Report, August 2010. The value for lead was derived from Ecoinvent v2.2 as included in SimaPro 7.2. 3. Values for fill reflect the average of values for sand and clay from Ecoinvent v2.2 as included in SimaPro 7.2.				

S.5.2 Life Cycle Valuation Method

This RIA assesses the value of the resource and environmental impacts associated with gypsum, cement, and fill production based on data from the empirical literature. These values reflect either the cost of the resources expended (i.e., energy and water) or the value of the environmental externalities associated with each impact category (i.e., greenhouse gas, NO_x, PM_{2.5}, and SO_x emissions). The methods and data supporting the valuation estimates for each impact category are as follows:

Energy: To estimate the value of the energy impacts associated with gypsum, cement, and fill production, this RIA relies upon energy cost data compiled by the U.S. Department of Energy from its Manufacturing Energy Consumption Survey (MECS).⁵⁵ The results of this survey include average energy costs per million Btu by 6-digit NAICS code, as well as industry-specific estimates of energy costs by fuel (e.g., coal, electricity, etc.). Under the assumption that production (as opposed to upstream activities) accounts for most of the energy consumption

⁵⁵ These data are reported in U.S. Department of Energy, Energy Consumption by Manufacturers, June 2009. Table 7.2.

associated with gypsum and cement, this RIA uses energy cost estimates specific to these industries from the MECS data. For portland cement, this RIA uses the average cost reported in the MECS data across all energy sources. In contrast, this RIA uses the reported diesel value for the gypsum sector, under the assumption that diesel-powered trucks and other equipment at gypsum quarries account for most of the energy associated with gypsum production. The MECS data do not include separate energy costs for fill production. To estimate fill-related energy costs in the absence of these data, this RIA uses the average cost of energy per million Btu as reported in the MECS data across all industries and energy sources.

Water: The economic value of water varies significantly by geography and use (e.g., irrigation versus power generation versus municipal use). Rather than explicitly incorporating these variables into a nation-wide estimate of the value of water, this RIA uses the estimated cost of pumping water from a supply source as an approximation of its value.⁵⁶ This cost likely understates the value that society places on water.

Greenhouse gas emissions: On December 7, 2009, EPA issued an endangerment finding declaring that CO₂ and five other greenhouse gases represent a threat to public health and welfare.⁵⁷ This RIA estimates the value of greenhouse gas emissions based on the social cost of CO₂ developed by the Interagency Working Group on Social Cost of Carbon.⁵⁸

NO_x, PM_{2.5}, and SO_x emissions: As documented in numerous EPA regulatory impact analyses and peer-reviewed studies, ambient PM_{2.5} and its precursors, including NO_x and SO_x, lead to several adverse health impacts, including premature mortality, chronic bronchitis, and other cardio-respiratory ailments. To monetize these effects as they relate to the emissions impacts associated with changes in beneficial use, this RIA applies monetized impact per ton estimates derived from Fann *et al.* (2009).⁵⁹ The values reported by Fann *et al.* differ by source category (e.g., mobile emission sources, point sources, etc.). This analysis uses the reported point source estimates to value emissions from the cement sector and mobile source estimates to value emissions associated with gypsum and fill production.

⁵⁶ The estimate applied in this RIA was obtained from Dr. H. Scott Matthews, Professor of Civil and Environmental Engineering and Engineering and Public Policy at Carnegie Mellon University and Research Director of Carnegie Mellon University's Green Design Institute, through personal communication on October 18, 2011. Dr. Matthews has published extensively on issues related to life cycle assessment.

⁵⁷ Federal Register, Vol. 74, No. 239, 66496-66546.

⁵⁸ Interagency Working Group on Social Cost of Carbon, United States Government, *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866*, Feb. 2010.

⁵⁹ Neal Fann, Charles M. Fulcher, and Bryan Hubble. "The influence of location, source, and emission type in estimates of the human health benefits of reducing a ton of air pollution," *Air Qual Atmos Health* (2009) 2: 169-176. The values in Fann *et al.* (2009) were updated by EPA and posted at <http://www.epa.gov/air/benmap/bpt.html>. This analysis uses the values from the EPA website. For purposes of exposition, the main text refers to these as the Fann *et al.* estimates.

This RIA makes two adjustments to the Fann *et al.* (2009) values. First, this RIA scales the Fann *et al.* dollar-per-ton estimates to reflect the dose-response coefficient for PM mortality employed in EPA's benefit-cost analysis of the 1990 Clean Air Act Amendments (CAAA).⁶⁰ The Fann *et al.* (2009) values reflect the dose-response function for PM mortality presented in Laden *et al.* (2006), which is the higher of the two estimates reported in EPA RIAs for air pollution rules. The lower estimate reported in EPA's air rule RIAs is from Pope *et al.* (2002).⁶¹ The dose-response value used in EPA's CAAA benefit-cost analysis (and in this analysis) is near the average of the Laden *et al.* and Pope *et al.* values.

The second adjustment is related to the valuation of direct PM_{2.5} emissions. While the emission factor sources outlined above include factors for PM_{2.5} in general, Fann *et al.* (2009) includes dollar-per ton values specific to the carbonaceous fraction of PM_{2.5}. This RIA therefore converts the dollar-per-ton values for carbon from Fann *et al.* to values that apply to PM_{2.5} more broadly based on the carbon fraction of PM_{2.5} as derived from EPA's benefit-cost analysis of the 1990 Clean Air Act Amendments.⁶²

This RIA's monetization of environmental impacts related to beneficial use does not capture the value of changes in lead, carbon monoxide, mercury, or PM₁₀ emissions. Although estimates of monetized impacts per ton were available for NO_x, PM_{2.5}, and SO_x, such data are not readily available for the other air pollutants included in Exhibit S-12 above. This RIA therefore underestimates the monetized value of the air emission impacts associated with changes in beneficial use.

Exhibit S-13 below presents the economic values applied in this RIA to changes in energy consumption; water consumption; and greenhouse gas, NO_x, PM_{2.5}, and SO_x emissions. The values reported in the exhibit reflect the methods outlined above for each impact category. The energy and water consumption values are not directly comparable with the air pollutant dollar-per-ton values due to differences in units, but among the air emission values, the estimates for PM_{2.5} are significantly greater than those for other pollutants. This reflects the fact that direct PM_{2.5} emissions become ambient PM_{2.5} with greater efficiency than NO_x or SO_x.

⁶⁰ See U.S. EPA, *The Benefits and Costs of the Clean Air Act from 1990 to 2020*, March 2011.

⁶¹ C.A. Pope, III, R.T. Burnett, M.J. Thun, E.E. Calle, D. Krewski, K. Ito, and G.D. Thurston, 2002. "Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution." *Journal of the American Medical Association* 287:1132-1141.

⁶² U.S. EPA (2011), *op cit.*

EXHIBIT S-13. VALUATION OF RESOURCE USE AND ENVIRONMENTAL EXTERNALITIES (YEAR 2011\$)

IMPACT CATEGORY	GYPSUM	PORTLAND CEMENT	FILL
Energy (\$/MMBtu) ¹	\$17.28	\$4.78	\$18.54
Water (\$/gal) ²	\$0.00003		
Greenhouse gases (\$/ton) ³	\$20.68		
NO _x (\$/ton) ⁴	\$9,500	\$8,700	\$9,500
PM _{2.5} (\$/ton) ⁴	\$348,800	\$39,900	\$348,800
SO _x (\$/ton) ⁴	\$36,500	\$53,200	\$36,500
Notes:			
1. Derived from U.S. Department of Energy, Energy Consumption by Manufacturers, June 2009. Table 7.2.			
2. Value provided by H. Scott Matthews, Professor of Civil and Environmental Engineering and Engineering and Public Policy at Carnegie Mellon University and Research Director of Carnegie Mellon University's Green Design Institute, October 18, 2011.			
3. Derived from Interagency Working Group on Social Cost of Carbon, United States Government, <i>Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866</i> , Feb. 2010.			
4. Derived from Neal Fann, Charles M. Fulcher, and Bryan Hubbell. "The influence of location, source, and emission type in estimates of the human health benefits of reducing a ton of air pollution," <i>Air Qual Atmos Health</i> (2009) 2: 169-176, as updated in U.S. EPA, PM _{2.5} Benefit Per Ton Estimates, http://www.epa.gov/air/benmap/bpt.html , accessed October 21, 2011. Estimates scaled to reflect PM mortality dose-response function from U.S. EPA, <i>The Benefits and Costs of the Clean Air Act from 1990 to 2020</i> , March 2011.			

Integrating the physical impact estimates in Exhibit S-12 with the valuation data in Exhibit S-13 above, Exhibit S-14 below summarizes the monetized value of the resource and environmental impacts per ton of gypsum, portland cement, and fill produced with CCR (for those impacts for which monetization was possible). As indicated in the exhibit, the estimated values for gypsum and portland cement are nearly the same at close to \$70 per ton, while the value for fill is much lower at less than \$2.30 per ton. The sharp discrepancy between fill and the other two products reflects the more extensive processing of materials required for gypsum and cement production. In addition, although the total impact per ton is similar for gypsum and portland cement, the two differ significantly in terms of the distribution of impacts across the six categories presented in the exhibit. PM_{2.5} emissions account for more than half of the estimated impact per ton for gypsum, whereas it represents less than 1% of impacts associated with portland cement. This is consistent with the differences in PM_{2.5} emissions values presented above in Exhibit S-12. In addition, although greenhouse gases represent approximately one-third of the impacts associated with portland cement, they represent less than 3% of gypsum-related impacts. This reflects the greater energy intensity of portland cement production (see Exhibit S-12), and also likely reflects the cement industry's greater use of coal, which is more carbon-intensive than most other energy sources.⁶³

⁶³ Although portland cement is more energy intensive than gypsum, the monetized energy impact for portland cement is less than that of gypsum because of the cement industry's lower energy costs per million Btu.

EXHIBIT S-14. VALUATION OF RESOURCE AND ENVIRONMENTAL IMPACTS PER TON OF GYPSUM, PORTLAND CEMENT, AND FILL PRODUCED (YEAR 2011\$)

IMPACT CATEGORY	GYPSUM	PORTLAND CEMENT	FILL
Energy	\$22.28	\$17.06	\$0.79
Water	\$0.67	\$3.78	\$0.04
Greenhouse gases	\$1.85	\$18.92	\$0.07
NO _x	\$1.41	\$16.71	\$0.26
PM _{2.5}	\$34.99	\$0.49	\$0.82
SO _x	\$7.60	\$12.94	\$0.31
Total	\$68.80	\$69.90	\$2.28

S.5.3 Life Cycle Valuation Results

Based on the methods outlined above, Exhibit S-15 below presents the estimated resource and environmental impacts associated with the changes in beneficial use under each regulatory option. Positive values in the exhibit represent the avoidance of impacts relative to the baseline, while negative values represent an increase in impacts. As indicated in the exhibit, this RIA projects that the changes in beneficial use for Regulatory Option 1 will lead to increased resource and environmental impacts for several impact categories, and that the beneficial use changes under Regulatory Options 2 and 3 will lead to reductions in impacts across all impact categories. The increase for select categories under Regulatory Option 1 reflects the decline in beneficial use for wallboard and fill applications under this option. Although the beneficial use of fly ash as a cement substitute in concrete is projected to increase under Regulatory Option 1, the impacts associated with reduced beneficial use in wallboard and fill applications outweigh this effect for PM, SO_x, and CO emissions. However, because cement production is more energy-, water-, greenhouse gas-, mercury-, lead-, and NO_x-intensive than gypsum or fill production, these impacts decline under Regulatory Option 1, despite the reduction in beneficial use in wallboard and fill applications. The reduction in resource and environmental impacts under Regulatory Options 2 and 3 is consistent with the increase in CCR beneficial use summarized in Exhibits S-10 and S-11.

EXHIBIT S-15. 3-YEAR ROLLING AVERAGE OF ANNUAL AVOIDED RESOURCE AND ENVIRONMENTAL IMPACTS ASSOCIATED WITH CHANGES IN BENEFICIAL USE, BY REGULATORY OPTION (POSITIVE VALUES REFLECT SAVINGS)

Regulatory Option 1 (Subtitle C Option)										
YEAR	ENERGY (MMBtu)	WATER (MILLION GAL)	GREENHOUSE GASES (TONS)	NO _x (TONS)	PM _{2.5} (TONS)	PM ₁₀ (TONS)	SO _x (TONS)	Hg (POUNDS)	Pb (POUNDS)	CO (TONS)
2015	1,400,000	81,000	740,000	1,500	-140	-500	-110	37.0	95	700
2020	800,000	92,000	920,000	1,900	-280	-1,100	-310	48.0	75	930
2025	2,100,000	130,000	1,200,000	2,500	-240	-940	-180	58.0	130	1,100
2030	-150,000	52,000	590,000	1,300	-250	-1,000	-330	33.0	18	630
2035-2112	-1,600,000	5,500	260,000	570	-270	-1,200	-450	19.0	-57	340
Regulatory Option 2 (Subtitle D Option)										
YEAR	ENERGY (MMBtu)	WATER (MILLION GAL)	GREENHOUSE GASES (TONS)	NO _x (TONS)	PM _{2.5} (TONS)	PM ₁₀ (TONS)	SO _x (TONS)	Hg (POUNDS)	Pb (POUNDS)	CO (TONS)
2015	240,000	5,700	36,000	62	11	60	28	1.3	13	24
2020	1,500,000	51,000	370,000	790	13	94	120	16	78	330
2025	1,900,000	63,000	420,000	1,000	26	96	170	18	89	400
2030	1,900,000	55,000	330,000	850	58	220	220	13	83	310
2035-2112	2,000,000	57,000	340,000	860	71	280	240	13	90	310
Regulatory Option 3 (Subtitle D-Prime Option)										
YEAR	ENERGY (MMBtu)	WATER (MILLION GAL)	GREENHOUSE GASES (TONS)	NO _x (TONS)	PM _{2.5} (TONS)	PM ₁₀ (TONS)	SO _x (TONS)	Hg (POUNDS)	Pb (POUNDS)	CO (TONS)
2015	-78,000	-5,200	-43,000	-110	10	45	5.4	-2.2	-4.1	-46
2020	1,000,000	35,000	260,000	540	6.9	69	74	11	56	230
2025	1,400,000	46,000	330,000	730	12	72	110	14	69	300
2030	1,500,000	50,000	340,000	780	25	120	140	14	75	310
2035-2112	1,700,000	48,000	290,000	680	61	270	200	11	81	250

Exhibit S-16 below displays the monetary value, in both present value and annualized terms, of changes in resource and environmental impacts by regulatory option and beneficial use application. Positive values in the exhibit represent a benefit associated with a reduction in resource use and environmental impacts relative to the baseline, and negative values represent a cost. As indicated in the exhibit, this RIA projects positive monetized impacts for Regulatory Options 2 and 3 and negative impacts for Regulatory Option 1. This reflects the increase in beneficial use across all applications under Regulatory Options 2 and 3 and the decline in beneficial use for fill and wallboard applications under Regulatory Option 1. Despite the fact that the overall impact for Regulatory Option 1 is negative, the monetized values related to concrete applications are positive under this option. As described above, concrete is the only one of the three beneficial use applications for which stigma is unlikely under Regulatory Option 1.

The results in Exhibit S-16 also show that wallboard and concrete applications account for a similar proportion of monetized impacts under Regulatory Options 2 and 3 but that they are of the opposite sign under Regulatory Option 1 (the Subtitle C Option). The difference under Regulatory Option 1 reflects the potential impacts of stigma on beneficial use. As described above, the analysis assumes that stigma would limit the beneficial use of wallboard under Regulatory Option 1 but would not limit CCR beneficial use in concrete.

EXHIBIT S-16. MONETIZED BENEFICIAL USE IMPACTS RELATIVE TO THE BASELINE, BY REGULATORY OPTION AND BENEFICIAL USE APPLICATION (MILLIONS OF YEAR 2011\$)

	Present Value: 2013-2112 (\$millions)		
BENEFICIAL USE APPLICATION	REGULATORY OPTION 1 (SUBTITLE C)	REGULATORY OPTION 2 (SUBTITLE D)	REGULATORY OPTION 3 (D-PRIME)
FGD Gypsum in Wallboard	(\$2,300)	\$200	\$180
Fly Ash as a Cement Substitute in Concrete	\$1,000	\$260	\$180
Fill	(\$130)	\$140	\$55
Total	(\$1,400)	\$600	\$410
	Annualized Value (\$millions)		
FGD Gypsum in Wallboard	(\$160)	\$14	\$12
Fly Ash as a Cement Substitute in Concrete	\$71	\$18	\$13
Fill	(\$9)	\$10	\$3.9
Total	(\$98)	\$42	\$29
Note: Values based on a discount rate of 7%			

Exhibit S-17 below presents the monetized value of each regulatory option's beneficial use impacts by impact category. The positive values for water, greenhouse gases, and NO_x under Regulatory Option 1 reflect the beneficial use of CCR in concrete applications as a substitute for portland cement. Although the decline in CCR beneficial use in fill and wallboard applications under Regulatory Option 1 leads to increased water use and increased greenhouse gas and NO_x emissions, the cement production avoided under this option is much more water-, greenhouse gas-, and NO_x-intensive than the production of wallboard or fill, as indicated in Exhibit S-12 above. For Regulatory Options 2 and 3, Exhibit S-17 shows that reduced energy use and avoided

PM_{2.5} emissions account for the largest share of the monetized benefits associated with increased beneficial use.

EXHIBIT S-17. MONETIZED BENEFICIAL USE IMPACTS RELATIVE TO THE BASELINE, BY REGULATORY OPTION AND IMPACT CATEGORY (MILLIONS OF YEAR 2011\$)

	Present Value: 2013-2112 (\$millions)		
IMPACT CATEGORY	REGULATORY OPTION 1 (SUBTITLE C)	REGULATORY OPTION 2 (SUBTITLE D)	REGULATORY OPTION 3 (D-PRIME)
Energy	(\$530)	\$180	\$120
Water	\$30	\$18	\$12
Greenhouse gases	\$210	\$80	\$55
NO _x	\$180	\$82	\$53
PM _{2.5}	(\$1,200)	\$150	\$110
SO _x	(\$82)	\$89	\$60
Total	(\$1,400)	\$600	\$410
	Annualized Value (\$millions)		
Energy	(\$37)	\$12	\$8
Water	\$2.1	\$1.3	\$0.9
Greenhouse gases	\$15	\$5.6	\$3.8
NO _x	\$13	\$5.7	\$3.7
PM _{2.5}	(\$84)	\$11	\$7.8
SO _x	(\$5.8)	\$6.3	\$4.2
Total	(\$98)	\$42	\$29
Note: Values based on a discount rate of 7%			

S.5.4 Alternative Valuation Results

As documented above, this RIA makes several assumptions about the management of CCR and the value of the lifecycle benefits associated with increased beneficial use. This section presents a sensitivity analysis related to three of these assumptions:

1. **Value per ton of changes in NO_x, SO_x, and direct PM_{2.5}:** The results presented above reflect monetized impact per ton values derived from adjustments to values developed from the methods documented in Fann *et al.* (2009). Specifically, this RIA scales the Fann *et al.* values to reflect the dose-response coefficient for PM mortality employed in EPA's benefit-cost analysis of the 1990 Clean Air Act Amendments (CAAA).⁶⁴ This coefficient is approximately halfway between the coefficients estimated in Pope *et al.* (2002) and Laden *et al.* (2006).⁶⁵ In contrast, the Fann *et al.* impact per ton values reflect the dose-response coefficient estimated in Laden *et al.* (2006).

⁶⁴ See U.S. EPA, *The Benefits and Costs of the Clean Air Act from 1990 to 2020*, March 2011.

⁶⁵ C.A. Pope, III, R.T. Burnett, M.J. Thun, E.E. Calle, D. Krewski, K. Ito, and G.D. Thurston, 2002. "Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution." *Journal of the American Medical Association* 287:1132-1141 and F. Laden, J. Schwartz, F.E. Speizer, and D.W. Dockery, 2006. Reduction in Fine Particulate Air Pollution and Mortality. *American Journal of Respiratory and Critical Care Medicine*. 173: 667-672.

2. **Greenhouse gas emissions:** To value the reductions in lifecycle greenhouse gas emissions associated with changes in beneficial use, the analysis above relies upon the social cost of CO₂ developed by the Interagency Working Group on Social Cost of Carbon in 2009.⁶⁶ In 2013, the Working Group published updated guidance that reflect advances in climate modeling and climate change impact assessment.⁶⁷
3. **Large-scale fill:** The results in this appendix also reflect an assumption that the rule would restrict beneficial use for large-scale fill applications, though such a provision is not included in the final rule.

Exhibit S-18 below presents alternative estimates of lifecycle beneficial use benefits that (1) reflect the dose-response coefficient for premature mortality in Laden *et al.* (2006) (2) reflect the updated social cost of carbon from the Interagency Working Group (2013), and (3) assume no restrictions on large-scale fill applications for CCR beneficial use. In presenting results that assume no restrictions on large-scale fill, the scenario reflected in Exhibit S-18 is the same as the analyzed option presented in Chapter 5. The exhibit presents baseline effects as well as impacts incremental to the baseline. Overall, the benefits of beneficial use under these alternative specifications exceed those presented above. This increase is consistent with the higher impact per ton values derived from Laden relative to those applied in Chapter 5 and the lifting of large-scale fill restrictions. In addition, the higher impacts reflect the increase in the social cost of carbon in the Interagency Working Group's 2013 guidance relative to its 2009 guidance.

⁶⁶ Interagency Working Group on Social Cost of Carbon, United States Government, *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866*, Feb. 2010.

⁶⁷ Interagency Working Group on Social Cost of Carbon, United States Government, *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866*, May 2013, Revised November 2013.

EXHIBIT S-18. ALTERNATIVE MONETIZED VALUE OF BENEFICIAL USE (7% AND 3% DISCOUNT RATES IN MILLIONS, 2011\$)

BENEFICIAL USE APPLICATION	BASELINE		ANALYZED OPTION IMPACTS RELATIVE TO THE BASELINE	
	7% DISCOUNT RATE	3% DISCOUNT RATE	7% DISCOUNT RATE	3% DISCOUNT RATE
A. Annualized:				
1. FGD Gypsum in Wallboard	\$860	\$940	\$10	\$16
2. Fly Ash as a Cement Substitute in Concrete	\$1,500	\$1,600	\$10	\$7
3. Fill	\$120	\$130	\$12	\$15
Column totals =	\$2,500	\$2,700	\$32	\$38
B. Present Value:				
1. FGD Gypsum in Wallboard	\$11,000	\$28,000	\$130	\$520
2. Fly Ash as a Cement Substitute in Concrete	\$21,000	\$52,000	\$130	\$220
3. Fill	\$1,700	\$4,200	\$160	\$480
Column totals =	\$35,000	\$85,000	\$430	\$1,200
Numbers are rounded to two significant figures. Totals may not sum due to rounding.				

ATTACHMENT 1 TO APPENDIX S:

*Analyzing the Impacts of RCRA Subtitle C on Beneficial Use of Coal
Combustion Residues*

April 29, 2012

Matt Kocoloski
5440 5th Ave.
Pittsburgh, PA 15213

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1. Background

Coal combustion residues (CCR), including fly ash, FGD gypsum, and other residues produced at coal fired power plants, can potentially be reused in manufacturing and construction applications, including concrete production, wallboard production, and fill applications. This ‘beneficial use’ of CCR can accrue benefits to both CCR suppliers and purchasers, as power plants can avoid the costs of disposing of coal combustion products and instead generate revenue from these material streams, while purchasers may be able to obtain a plentiful, low cost substitute for raw materials used in their supply chain.

The policy options under consideration by EPA could significantly alter the national profile of CCR beneficial use. Specifically, these options could impact beneficial use in four primary ways:

1. **Stigma Effect (Subtitle C Option only):** Even though CCR is not considered hazardous when beneficially used under the Subtitle C Option, ACAA has argued that 14 states will ban beneficial use of CCR if it is considered hazardous when disposed. This will limit demand within these states.
2. **Increased cost of disposal:** CCR disposal costs are higher under all regulatory options under consideration than under the baseline, making beneficial use a more economically attractive management option. Thus, while stigma may dampen beneficial use under the Subtitle C option, the increased cost of disposal will have the opposite effect.
3. **Quantity of CCR Available for Beneficial Use:** With the exception of FGD gypsum, the estimated baseline CCR quantities do not include CCRs that are wet managed, as wet material (except for FGD gypsum) cannot be beneficially used. Under the Subtitle C and Subtitle D options, however, wet handling will be discontinued after 2020. Thus, the quantity of CCR available for beneficial use increases after 2020 under these options.
4. **Restrictions on Large-scale Fill Applications:** Under the rule, EPA is prohibiting the use of CCR in large-scale fill applications. This restriction will limited the potential demand for CCR in fill-related uses.

The goal of this analysis is to assess the extent to which the CCR regulatory policy options that EPA is considering would lead to an increase or decrease in beneficial use of CCRs in an effort to provide guidance for policymakers. This analysis incorporates the four drivers summarized above to examine how these options could impact the optimal configuration of CCR beneficial use. This analysis also examines changes in regional beneficial use and transportation of CCR as a result of such a policy.

1.1 Specification of Scenarios

As noted above, the Subtitle C option requires that CCR be managed as a hazardous waste unless the material is beneficially used.⁶⁸ The beneficial use impacts of this option depend in large part on the stigma effect associated with the Subtitle C designation. For this analysis, we examined three analytic variants of the Subtitle C option that differ in their specification of the stigma effect, as summarized below. In addition, the analysis included the Subtitle D and Subtitle D Prime scenarios to examine the impacts of varying disposal cost assumptions. The following list provides brief descriptions of each of the scenarios modeled in this analysis.

1. **Baseline Scenario.** CCR is not classified as a hazardous waste. Assumes no impacts on CCR supply and no stigma effect for CCR demand. Optimization model results are calibrated to an exogenous beneficial use forecast.
2. **Subtitle C.** For all Subtitle C scenarios, the analysis assumes that supply of CCR increases due to the discontinuation of wet handling (see Figure), and avoided disposal costs for CCR increase as well (see Figure 7). Demand for CCR is impacted differently for each of the following three variants.
 - a. **Best Estimate.** Assumes 1) no stigma for fly ash used in concrete production, 2) wallboard plants located in the 14 ACAA states cannot use FGD gypsum for the production of residential wallboard, and 3) residential applications of fill decline to zero.
 - b. **Worst Case.** Assumes that there is no beneficial use for concrete, wallboard, or fill applications in the 14 ACAA states. Furthermore, residential applications in non-ACAA states decline to zero.
 - c. **Optimistic.** No stigma effect is assumed.
3. **Subtitle D.** No stigma effect is assumed. Estimates for avoided disposal costs are different from those used in other scenarios.
4. **Subtitle D Prime.** No stigma effect is assumed. Estimates for avoided disposal costs are different from those used in other scenarios. Avoided disposal costs slightly lower than under the Subtitle D scenario.

⁶⁸ The Subtitle C Option represents Regulatory Option 1, as described in the main body of the RIA. The Subtitle D Option and Subtitle D Prime Option correspond to Regulatory Options 2 and 3, respectively.

2. Data Sources and Methods

2.1 CCR Supplies⁶⁹

CCR supply estimates were developed for 511 coal-fired power plants throughout the United States based on 2009 CCR generation data from DOE and DOE projections of coal-fired electricity generation (relative to 2009). We define CCR supply as CCR that may be used in beneficial use applications, which includes dry-handled fly ash, all FGD gypsum, and all other dry-handled CCR. The CCR supply projection dataset contains estimates for the volumes of fly ash, FGD gypsum, and other residues available at each of the 511 power plants for the 100-year period stretching from 2013 to 2112. The dataset also contains separate supply projections for the baseline, the Subtitle C scenario, the Subtitle D option, and Subtitle D prime. As noted above, the wet handling of CCR is discontinued after 2020 under the Subtitle C and Subtitle D options.

Figure illustrates estimates for the total supply of CCR available for beneficial use for the years from 2013 through 2035. Post-2035 quantities are assumed to be equal to the 2035 values. Baseline projections indicate the total supply of CCR steadily increases from 105 million tons to over 120 million tons between 2012 and 2035, but under the Subtitle C scenario, there is a significant increase after 2020, the last year when impoundments may continue to receive CCRs under the Subtitle C option. As a result of the discontinuation of wet handling, an additional 15 million tons of fly ash and 6 million tons of other residues are projected to become available for beneficial use, and the total supply remains roughly 20 million tons higher than projected for the baseline scenario through 2035. Total supply of CCR under Subtitle D and Subtitle D Prime follow patterns similar to those shown for Subtitle C, though the increase after 2020 is smaller under Subtitle D Prime.

⁶⁹ This discussion of CCR supply focuses on the supply of dry-handled CCR available for beneficial use.

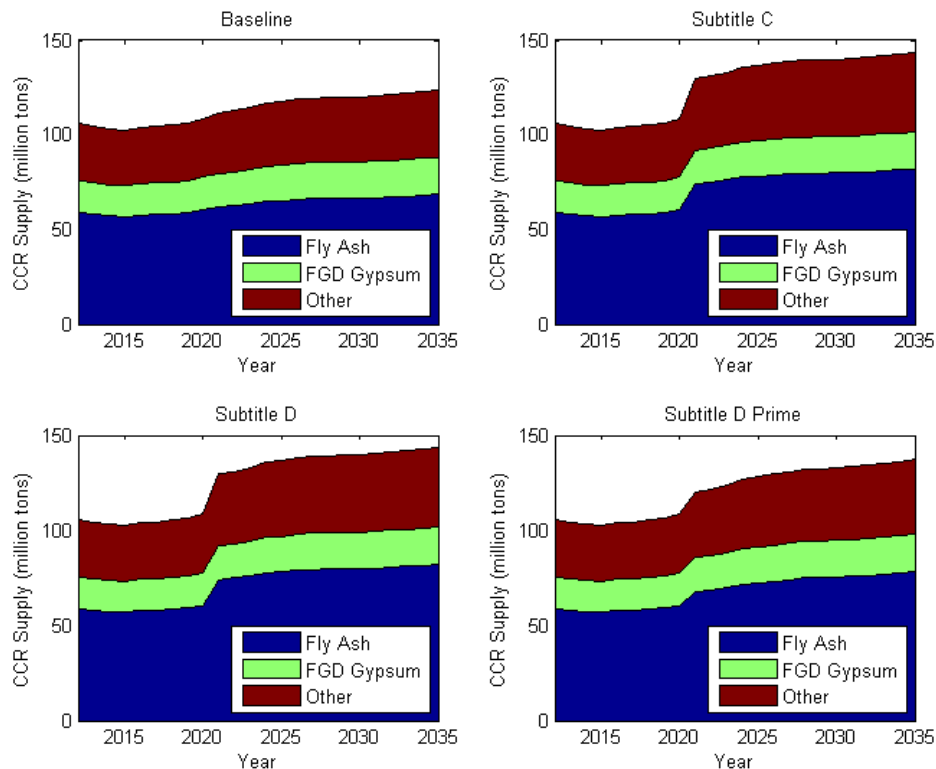


Figure 1. Projections of total CCR availability for beneficial use from 2012 to 2035, for Baseline, Subtitle C, Subtitle D, and Subtitle D Prime scenarios.

CCR supplies are generated at coal-fired power plants, so CCR production is greatest in those areas of the country that rely most heavily on coal-powered electricity. Figure 1 shows that CCR supplies are estimated to be primarily in the eastern half of the United States, especially throughout Pennsylvania, along the Ohio River, and in eastern Texas. Much of the country's population (and therefore, as discussed below, potential demand for concrete and fill applications) is found along the east coast.

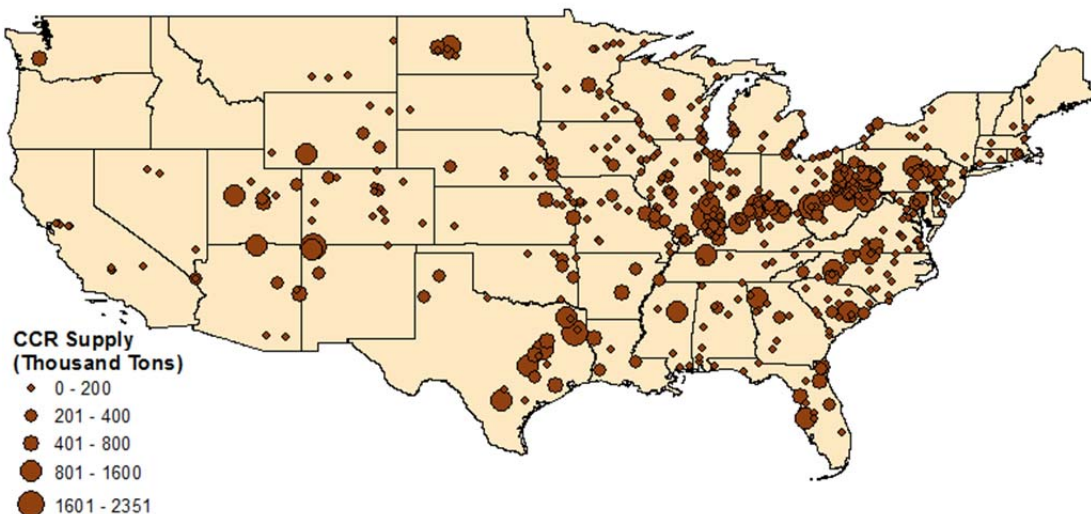


Figure 1. Spatial distribution of total CCR supply for Baseline scenario, 2012.

2.2 Potential (Maximum) CCR Demands

The maximum quantity of CCR that may be beneficially used in any given year depends on the total output of those industries that use CCRs as an input. As part of our analysis, we therefore capped CCR demand for each beneficial use application: fly ash use in concrete production, FGD gypsum use in wallboard production, and use of all CCR types in fill applications. Figure 2 provides those estimates for years ranging from 2012 to 2035 for the baseline scenario. For the baseline scenario (as well as all of the other demand scenarios), demand from fill applications dominates the total demand. Fill applications could use up to 300 million tons of CCR per year in the baseline, compared to demands of at most 20 million tons per year for gypsum in wallboard production and 24 million tons per year of fly ash for concrete. Maximum CCR demand is projected to increase by slightly over 30% for all three applications from 2012 to 2035.

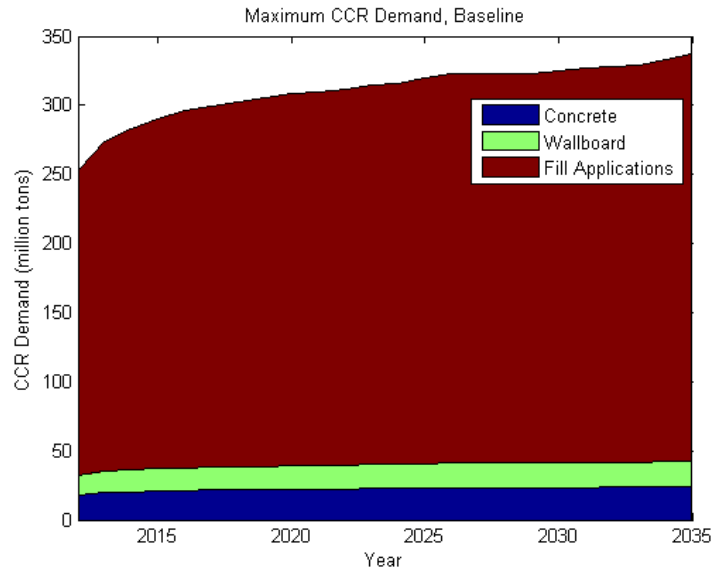


Figure 2. Projections of Potential CCR demand by end use for Baseline scenario, 2013 – 2035.

The stigma effect associated with beneficial use of CCR could result in a significant drop in potential CCR demand. Due to uncertainty regarding the severity of the stigma effect, a number of different demand scenarios were considered in this analysis for the Subtitle C option. Figure 3 compares maximum demand for CCR in these alternative scenarios to the maximum CCR demand estimated for the baseline. The figure also includes the Subtitle D and D prime options, for which there are no stigma effects.

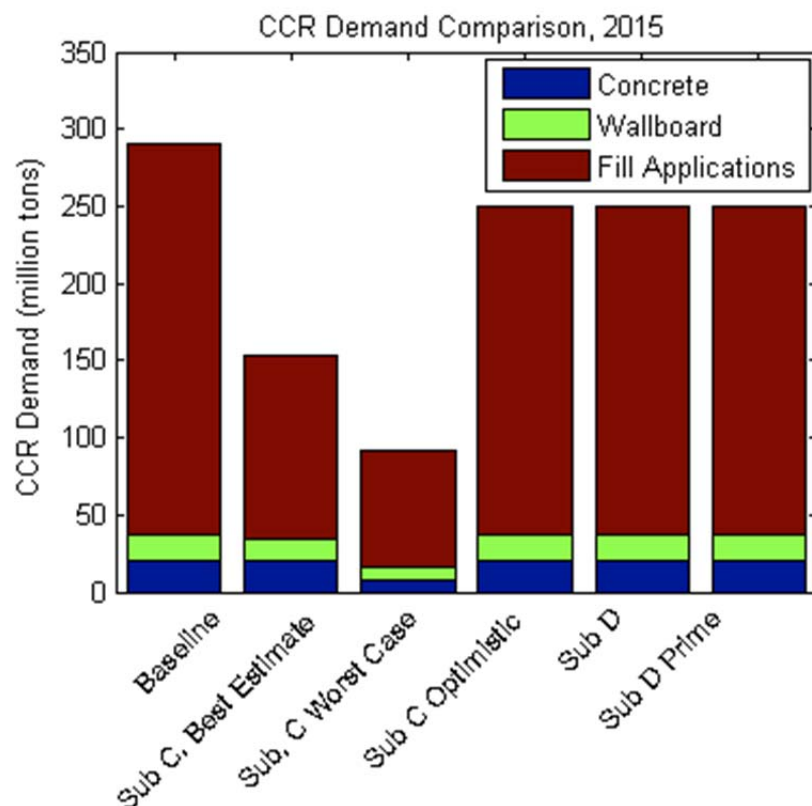


Figure 3. Projections of maximum CCR demand by end use in 2015 across demand scenarios.

On a spatial level, maximum CCR demand was modeled differently for the various types of potential end uses. In the cases of fly ash used in concrete production and CCR used in fill applications, potential demand for CCR was geographically distributed on a county-by-county basis according to population. County-level demands for fly ash to be used in concrete production and for CCR to be used in fill applications were estimated for over 3000 counties in the continental United States by taking the total national-level demand and multiplying it by the percentage of the national population contained within that county.

Potential gypsum demands were estimated for individual wallboard production facilities.⁷⁰ Wallboard production facilities capable of accepting FGD gypsum are found primarily throughout coal-heavy Midwestern areas and some portions of the Southeast. Figure 4 shows the locations of FGD gypsum demands in the baseline, along with demand for fly ash for concrete production. Like demand for fly ash in concrete, demand for CCR for fill applications was assumed to be proportional to population, so the spatial density of the demand for those two end uses is the same. Compared to Figure 1, which shows the location of CCR supplies, Figure 4

⁷⁰ Production capacities for individual plants obtained from Claudius Peters Technologies, Global Gypsum Directory 2008-2009. Information on the extent to which each plant uses FGD gypsum provided by Michael Gardner, Gypsum Association, personal communication, January 19, 2010.

shows a significant amount of potential demand for fly ash (and therefore fill applications as well) along the Pacific Coast, far from many CCR supply locations.

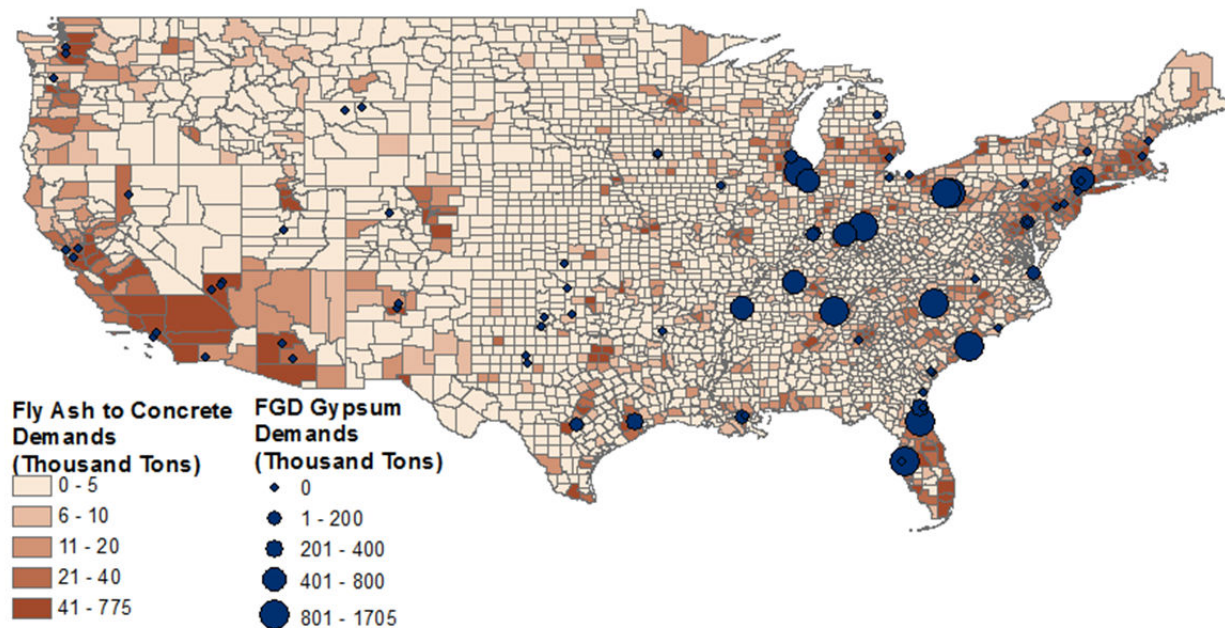


Figure 4. Spatial distribution of potential demand for fly ash in concrete production and FGD gypsum in wallboard production for Baseline scenario, 2013.

As described above, one of the primary impacts of a policy classifying CCR as a hazardous material when disposed can be thought of as a stigma effect, where some states restrict beneficial use of CCR as a result of this classification. Figure 5 shows the new spatial distribution of potential demand that would result from this policy assuming the 14 states identified by ACAA would prohibit the beneficial use of CCR. A number of states with large populations, and large estimated demands for fly ash and CCR for use in fill applications, are assumed to totally restrict beneficial use, including Texas, Florida, and Pennsylvania. The stigma effect primarily affects demands for concrete substitute and fill applications, though some wallboard facilities might also stop accepting FGD gypsum.

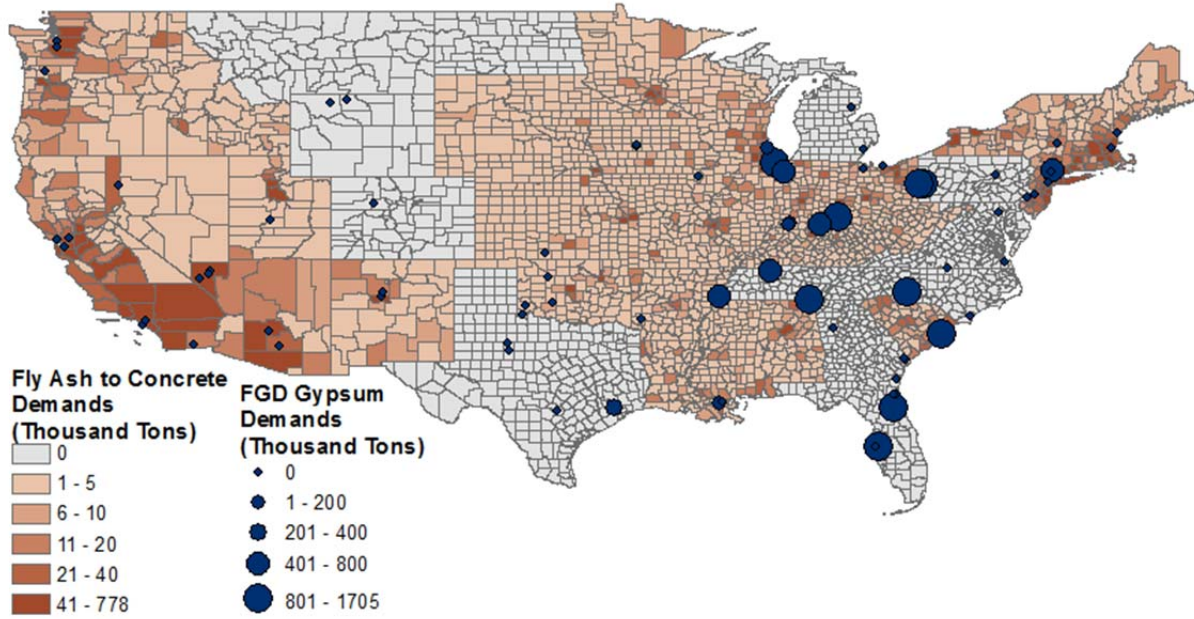


Figure 5. Spatial distribution of potential demand for fly ash in concrete production and FGD gypsum in wallboard production for Subtitle C Worst Case policy scenario, 2013.

2.3 Model Formulation

Shipments of CCR to each potential end use were modeled using a linear program (LP). The LP minimizes the cost of CCR beneficial use (or maximizes the benefit) by optimizing shipments of CCR from supplies to demands, subject to constraints on both CCR supply and demand sites.

The objective function for the model represents the total cost of using CCR. Let i represent the set of all CCR supplies (power plants), and let j represent the set of all CCR demands (counties in the cases of concrete production and fill applications, and wallboard plants in the case of wallboard production). Let m represent the three types of CCR, namely, fly ash, FGD gypsum, and other residues, and let n represent the three types of CCR end use: concrete, wallboard, and fill applications. The objective function can then be written as:

$$\text{Minimize } \sum_m \sum_n \sum_i \sum_j c(i, j, m, n) \times x(i, j, m, n)$$

In this formulation, $x(i, j, m, n)$ represents the tons of CCR type m shipped from supply i to demand j to be used in end use type n , and $c(i, j, m, n)$ represents the net cost of that shipment, per ton of residue.

The net cost for each shipment, $c(i, j, m, n)$, was comprised of different terms for each beneficial use combination. For all five beneficial use combinations, $c(i, j, m, n)$ contained terms for the avoided disposal cost, or the cost of disposing of the residue that no longer had to be incurred if it were used in another application, and shipping cost required to transport the residue from

power plant to demand site, estimated as \$0.1602 per ton-mile for truck transportation⁷¹, multiplied by a circuitry factor of 1.23⁷², multiplied by the straight-line distance between the two locations. The cost function also contained avoided costs for cement, virgin gypsum, and sand or gravel for fill applications, since those materials would no longer need to be purchased if they were displaced by CCR material. Shipments of fly ash to be used in concrete production were also assumed to incur a beneficiation cost, while shipments of gypsum to be used in wallboard production incurred dewatering costs.

Table 1 summarizes the cost parameters for each beneficial use combination. Cost parameters are shown in the leftmost column, with the value for each parameter for each beneficial use combination provided under the corresponding columns. Values that represent benefits of beneficial use are shown in green cells, while costs of beneficial use are highlighted in red.

Table 1. Summary of cost parameters.

Cost Parameter (values given in \$/ton)	Fly Ash		Gypsum		Other
	Concrete	Fill	Wallboard	Fill	Fill
Avoided Cement ¹	93.57				
Avoided Gypsum ²			7.50		
Avoided Fill ³		6.79		6.79	6.79
Avoided Disposal	See Figure 6.				
Beneficiation ⁴	1.53				
Dewatering Capital ⁵			717,000 / supply		
Dewatering O&M ⁶			3.00		
CCR Shipping	0.1602 x distance				
Notes					
1. Hendrik G. van Oss, USGS, Mineral Commodity Summaries - Cement, January 2011. Estimate reflects average of values reported for 2006 through 2010.					
2. Robert D. Crangle, Jr., USGS, Mineral Commodity Summaries - Gypsum, January 2011. Estimate reflects average of values reported for 2006 through 2010.					
3. F Wallace P. Bolen, USGS, Mineral Commodity Summaries - Sand and Gravel (Construction), January 2011. Estimate reflects average of values reported for 2006 through 2010.					
4. According to ACAA's David Goss (personal communication, June 25, 2008), approximately 2 million of the 15 million tons of fly ash beneficially used in concrete in the U.S. (or 13.3%) undergoes beneficiation. In addition, based on the range of beneficiation costs presented in Electric Power Research Institute, Beneficiation of Fly Ash Containing Mercury and Carbon, this RIA estimates that a reasonable central tendency value for the cost of beneficiation is approximately \$10 per ton (in year 2004\$). The estimate of \$1.53 per ton presented in this exhibit reflects this \$10 estimate multiplied by the probability of fly ash requiring beneficiation (13.3%), scaled for inflation.					
5. U.S. DOE, National Energy Technology Laboratory, Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, August 2007.					
6. E. Cheri Miller, TVA, "Flue Gas Desulfurization (FGD) Gypsum Production , Processing, and Disposal," presentation. Undated.					

⁷¹ Bureau of Transportation Statistics, *National Transportation Statistics 2010*, Table 3-17.

⁷² Estimated in a previous analysis by the author that compared the great circle distance between locations to the distance estimated by a shortest path algorithm along the national highway network.

Avoided disposal costs, or the costs that power plants would incur if they decide not to beneficially use CCR, were estimated specifically for each power plant. Avoided disposal costs were also assumed to vary across different policy scenarios. Figure 6 summarizes the distribution of avoided disposal costs for each policy scenario modeled in this study for the year 2030. Figure 6 provides cumulative distribution functions for each scenario representing the percentage of total CCR supply available at a given avoided disposal cost. For all policy scenarios, the majority of CCR supply has a very small avoided disposal cost, on the order of \$5/ton or less. Avoided disposal costs begin to increase significantly for the most expensive 30% of CCR supply, to between \$50 and \$250 per ton depending on scenario. Above the 95th percentile, avoided disposal costs increase dramatically, due to the fact that there are a few plants with very limited volumes of CCR supply, and making the necessary capital investments to properly dispose of these limited volumes leads to a very high per unit disposal cost.

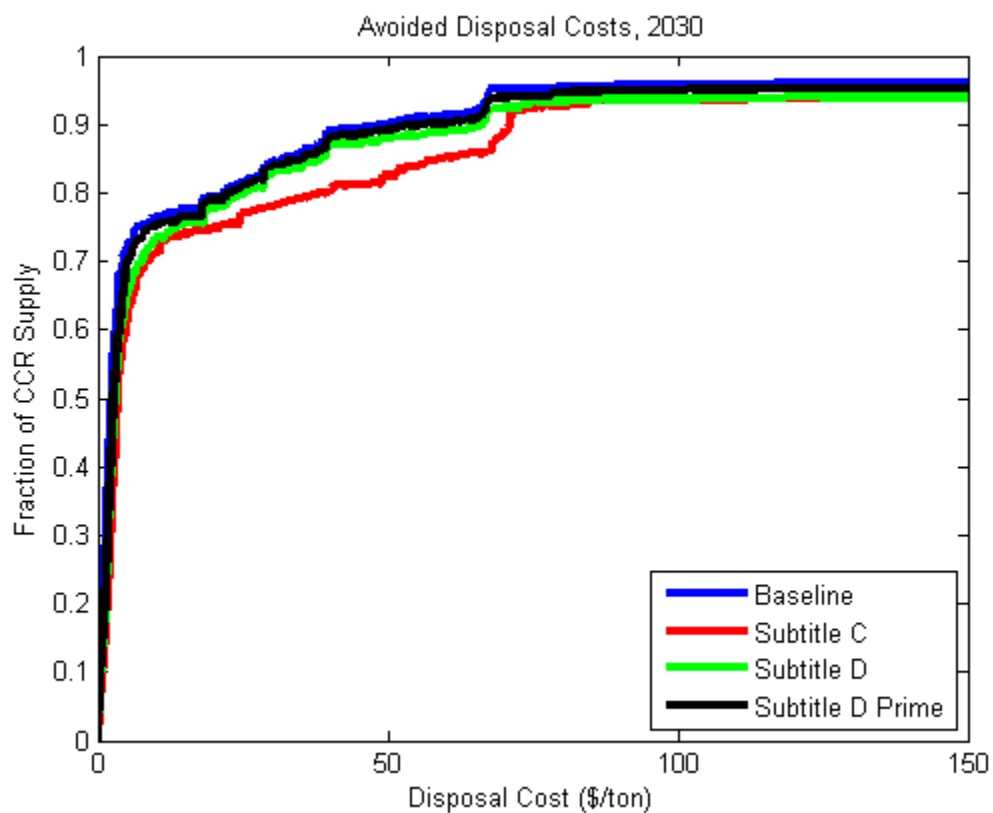


Figure 6. Avoided CCR disposal cost CDFs both Baseline, Subtitle C, Subtitle D, and Subtitle D Prime scenarios for the year 2030.

Constraints for the model ensured that: 1) total shipments of each CCR type m from power plant i do not exceed total available supply at that site, 2) total shipments of each CCR to demand site j do not exceed the total available demand at that site of type n , and 3) total beneficial use of each demand type n exceed the assumed minimum beneficial use levels:⁷³

$$\sum_n \sum_j x(i, j, m, n) \leq S(i, m) \quad (1)$$

$$\sum_m \sum_i x(i, j, m, n) \leq D(j, n) \quad (2)$$

$$\sum_m \sum_i \sum_j x(i, j, m, n) \geq Q_{min}(n) \quad (3)$$

Collectively, these constraints guarantee that supply and demand constraints are not exceeded, but that the solution meets exogenously estimated minimum quantities of beneficial use for each of the three end use types.

Based on this formulation, the model was calibrated to the baseline projection of beneficial use. For details on the calibration procedure, and the resulting values for the calibration parameters, see sub-appendix A. To develop the baseline projection, we assumed that the annualized growth in the beneficial use rate observed for the 2002-2009 period extends to future years. These projections of the beneficial use rate were then applied to projections of CCR generation.

3. Results and Discussion

3.1 Beneficial Use Quantities

Different policy scenarios modeled in this study would likely have very different impacts on total volumes of CCR beneficial use. Figure 7 shows the total beneficial use estimated for each of the six policy scenarios (i.e., baseline, three variants of the Subtitle C scenario, the Subtitle D option, and Subtitle D Prime) between 2013 and 2035. Figure 7 provides estimates of total beneficial use, including all types of CCR and all potential CCR end uses; results for individual CCR types and end uses are provided below. The baseline scenario, shown in black, indicates a steady increase in CCR beneficial use. Relative to the baseline, the Subtitle C Best Estimate and Subtitle C Worst Case scenarios show a decrease in beneficial use for all years in the analysis. In contrast, the Subtitle C Optimistic, Subtitle D, and Subtitle D Prime scenarios show an increase in CCR beneficial use across the entire time frame.

⁷³ The analysis assigns minimum demand values for segments of the beneficial use market unaffected by the rule. For example, for the Subtitle C worst case, the minimum demand for fly ash used in concrete was set as the portion of baseline demand associated with non-residential applications in non-ACAA states.

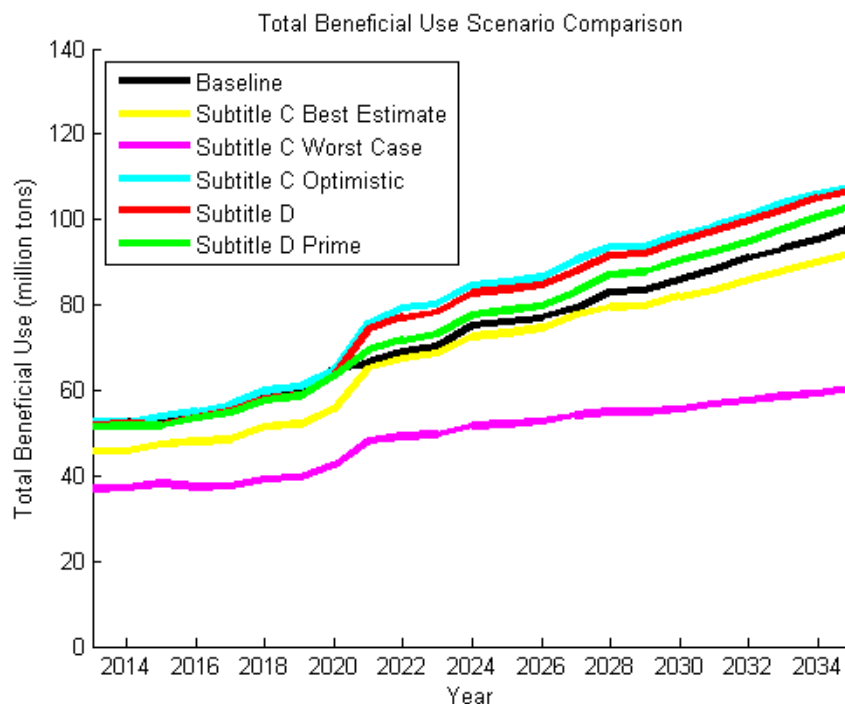


Figure 7. Total beneficial use of CCR by scenario for 2013 through 2035.

The three primary policy impacts identified in the *Background* section (the stigma effect, increased cost of disposal, and increased quantities of CCR availability) drive these results. The strongest of these impacts (for the Subtitle C option) is the stigma effect, where certain states limit or completely prohibit beneficial use of CCR should it be classified as hazardous when disposed. The Subtitle C Best Estimate and Subtitle C Worst Case scenarios both model the stigma effect, with a stronger effect in the Subtitle C Worst Case scenario. As a result, both scenarios see a drop in beneficial use relative to the baseline, with a much larger drop for the Subtitle C Worst Case. The remaining policy scenarios do not model a stigma effect, and therefore see an increase in beneficial use due to the other two policy impacts, which encourage beneficial use.

The second most influential impact is the increase in CCR availability due to the discontinuation of wet handling after 2020. This impact leads to the uptick in beneficial use seen in all policy scenarios in 2021, and the sustained higher levels of beneficial use through 2035. The Subtitle C Optimistic, Subtitle D, and Subtitle D Prime scenarios all show levels of beneficial use very close to the baseline from 2013 to 2020, but are noticeably higher in later years, after the assumed discontinuation of wet handling and subsequent increase in CCR supply. This uptick is also seen for the scenarios that model the stigma effect, such as the Subtitle C Best Estimate scenario, where the increase in CCR supply after 2020 almost offsets the drop in demand from the stigma effect.

The least influential driver is the increase in disposal costs. Some of the assumed increases are significant; however, the largest increases in disposal cost are generally experienced by plants with high disposal costs from the start. Figure 6 shows CDFs for the avoided disposal cost in different scenarios, and indicates that the lowest 60% of CCR supply has a relatively low

avoided disposal cost across all scenarios. While some plants with higher disposal costs do see a large increase from the baseline scenario, these are generally plants that already practice beneficial use. Plants with low avoided disposal costs in the baseline still have low avoided disposal costs in the policy scenarios, so the marginal effect is fairly small.

Different avoided disposal costs do still have a noticeable impact; the only difference between the Subtitle C Optimistic and Subtitle D scenarios is a different set of avoided disposal costs, which does lead to a change in the results. However, the magnitude of this impact is smaller than either the stigma effect or the impact of the increase in post-2020 CCR supply.

Figure 8 illustrates the breakdown of total CCR beneficial use by application—concrete production, wallboard production, or fill applications—for all policy scenarios for the year 2035. Concrete production is largely consistent across all scenarios with the exception of the Subtitle C Worst Case scenario. This scenario is the only one that assumes a stigma effect for use of fly ash in concrete production, which results in a large decrease in beneficial use. Use of FGD gypsum in wallboard is also consistent across most of the scenarios, seeing a decrease from the baseline in only the Subtitle C Best Estimate and Subtitle C Worst Case scenarios. The remaining variation in total beneficial use is due to changes in CCR used in fill applications, which decreases from the baseline in the Subtitle C Best Estimate and Subtitle C Worst Case scenarios and increases in the Subtitle C Optimistic, Subtitle D, and Subtitle D Prime cases.

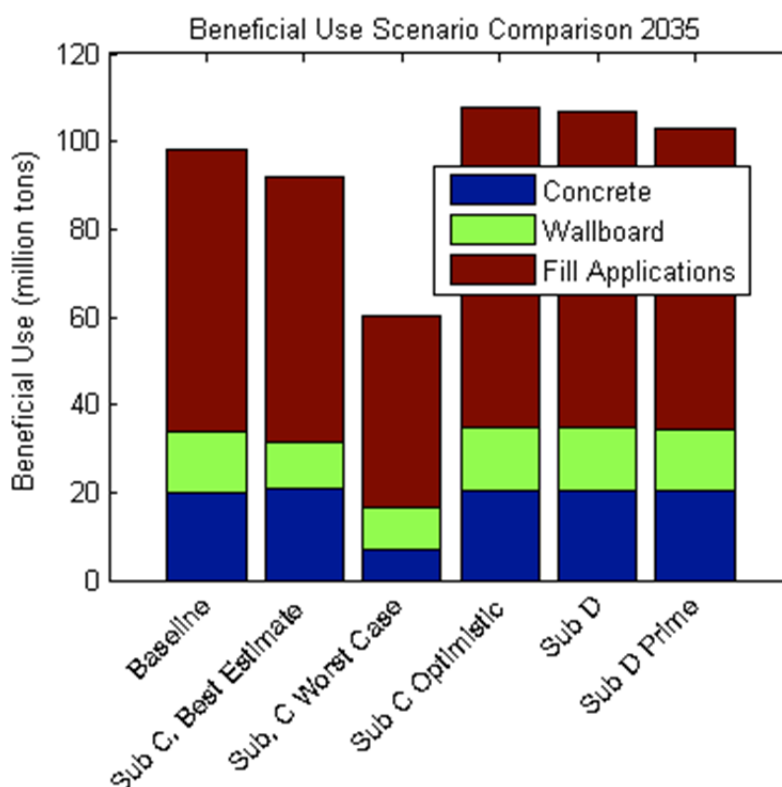


Figure 8. Beneficial Use by End Use, All Scenarios, 2035.

Figure 9 provides a more detailed comparison of the baseline and Subtitle C Best Estimate scenarios, showing quantities of CCR going to concrete production, wallboard production, and fill applications from 2013 through 2035. The Subtitle C Best Estimate scenario assumes stigma effects for both wallboard production and residential fill applications, leading volumes for these end uses to drop across the entire time frame. No stigma effect is assumed for fly ash used in concrete production, however. As a result, concrete production becomes a relatively more attractive end use than the stigmatized fill applications or wallboard production, and sees a modest increase across the time frame.

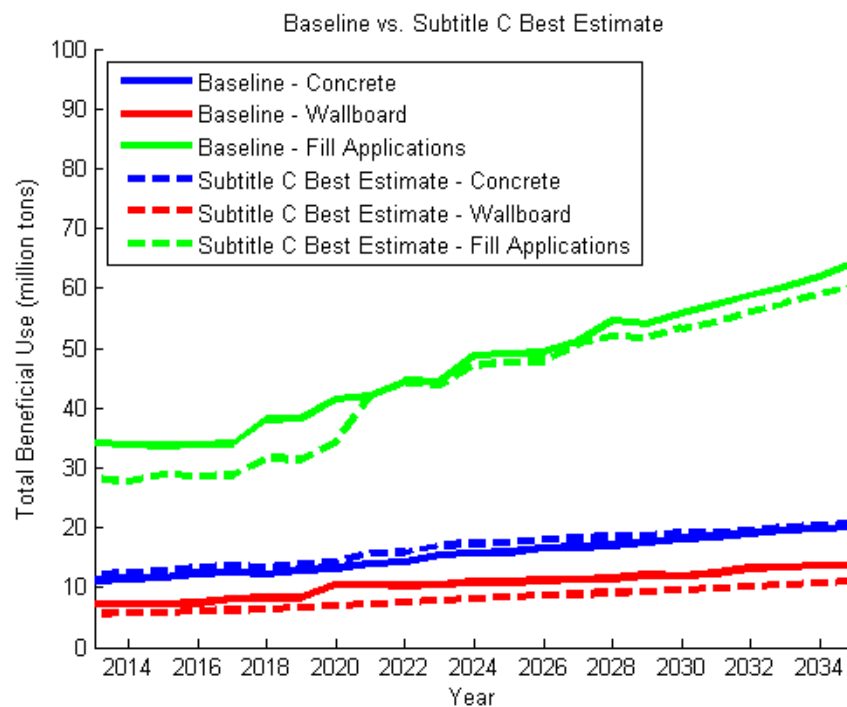


Figure 9. Beneficial use by end use, Baseline and Subtitle C Best Estimate scenarios.

Results for the Subtitle C Worst Case scenario are compared to the baseline results in Figure 10. The Subtitle C Worst Case scenario sees noticeable drops in beneficial use for all three end uses for all years in the analysis relative to the baseline. Concrete production from CCR drops by 55% – 65%, wallboard production by 20% - 30%, and fill applications by 15% - 32%. Beneficial use of CCR in wallboard production and fill applications sees a small uptick around 2020, but not enough to offset the large reductions from the widespread stigma effect.

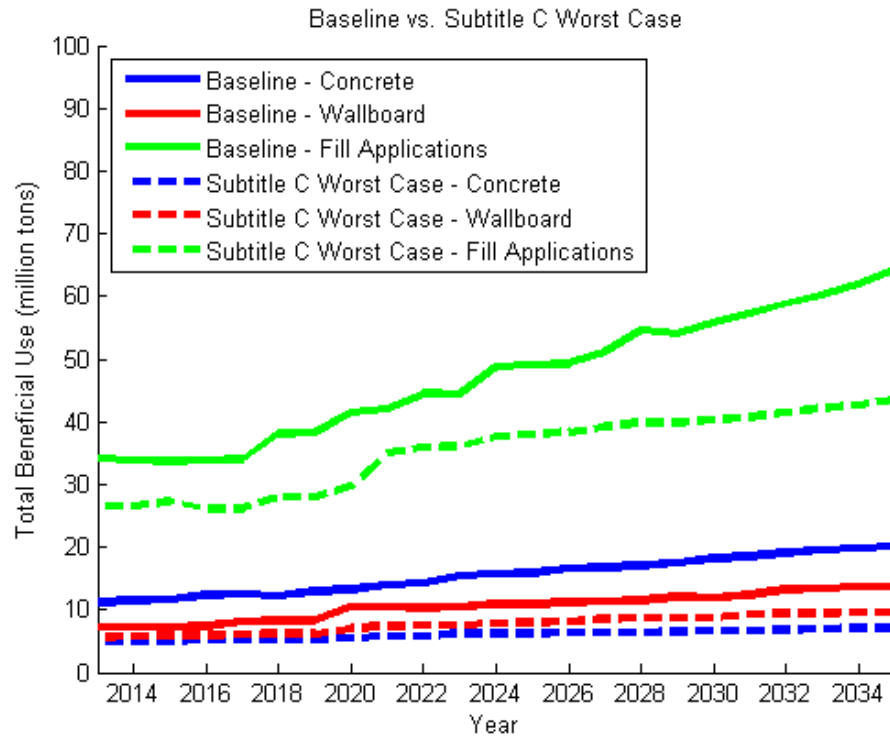


Figure 10. Beneficial use by end use, Baseline and Subtitle C Worst Case scenarios.

Figure 11 compares the baseline and Subtitle C Optimistic scenarios from 2013 to 2035. There is little difference between the two scenarios up to 2020. After 2020, however, the Subtitle C Optimistic scenario sees a 20% - 30% increase in beneficial use for fill applications due primarily to the increase in CCR supply resulting from the discontinuation of wet handling. Beneficial use of CCR in the Subtitle D and Subtitle D Prime scenarios show similar patterns to those for Subtitle C Optimistic, but with smaller increase in fill applications relative to the baseline.

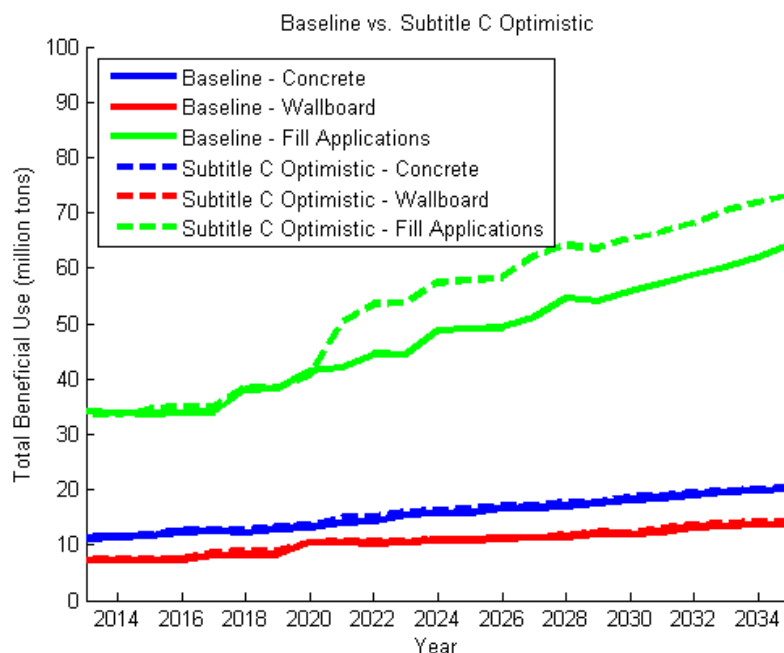


Figure 11. Beneficial use by end use, Baseline and Subtitle C Optimistic scenarios.

3.2 Percentage of Supply Used

Figure 12, Figure 13, and Figure 14 provide more insight into beneficial use across the different policy scenarios by illustrating the percentage of supply used by application. Figure 12 shows that, for the baseline scenario, 80% of the total supply of fly ash is used, with 30% going to concrete production and 50% being used in fill applications. Wallboard production accounts for 70% of FGD gypsum supply, while 15% of gypsum and 70% of other residues are used in fill applications.

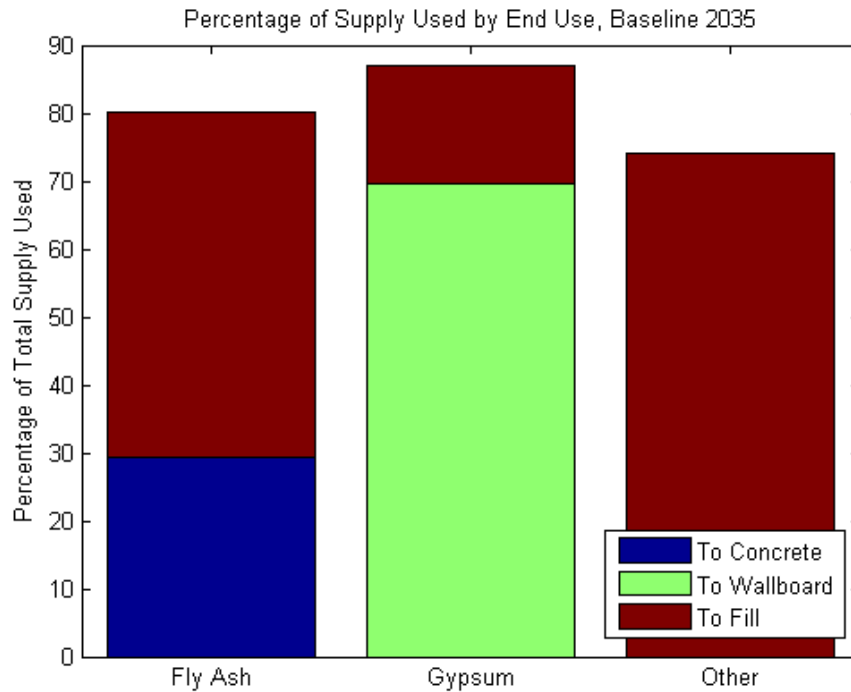


Figure 12. Percentage of Supply Used by End Use, Baseline scenario for 2035.

Figure 13 shows a much different picture for the Subtitle C Worst Case scenario. Total beneficial use values for fly ash, gypsum, and other residues range from 40% to 55%, in contrast to the 75% to 85% from the baseline scenario. The Subtitle C Worst Case scenario assumes both higher levels of dry-handled CCR supply and tighter restrictions on beneficial use than the baseline scenario, leading to significantly lower rates of utilization for all types of CCR.

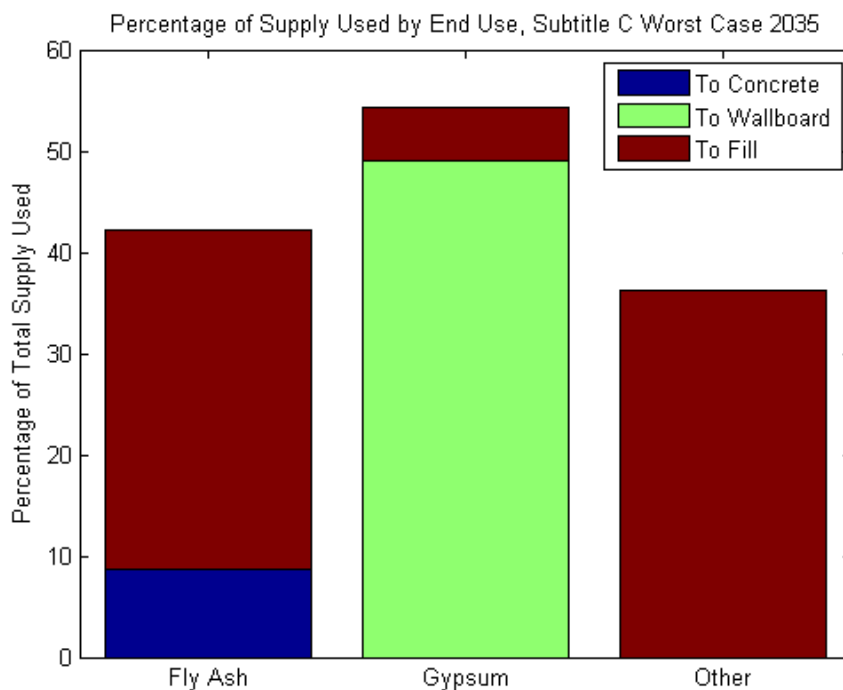


Figure 13. Percentage of Supply Used by End Use, Subtitle C Worst Case scenario for 2035.

The results for the Subtitle C Optimistic scenario shown in Figure 14 are very similar to those shown in Figure 12 for the baseline scenario. Total beneficial use of fly ash, gypsum, and other residues ranges from 70% to 85%, with the majority of gypsum going to wallboard production and the majority of fly ash and other residues going to fill applications. The Subtitle C Optimistic policy scenario does, however, assume a greater quantity of dry-handled CCR supply than the baseline scenario, so the similar percentages correspond to a greater overall level of beneficial use.

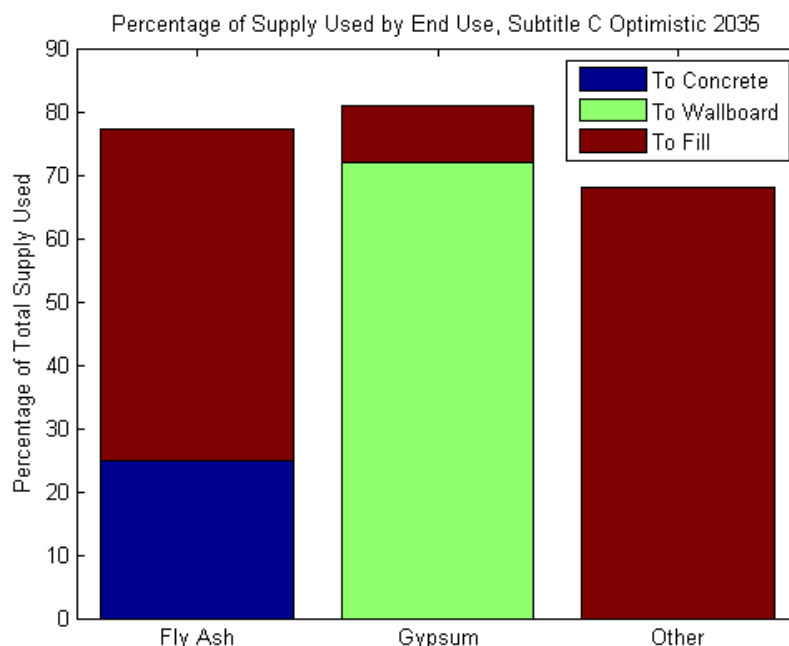


Figure 14. Percentage of (dry-handled) Supply Used by End Use, Subtitle C Optimistic scenario for 2035.

3.3 Percentage of Potential Demand Met

Figure 15, Figure 16, and Figure 17 provide results similar to those shown above, but examine the results from the demand perspective rather than the supply perspective. Figure 15 shows that, in the baseline scenario, over 80% of potential demand for CCR for concrete production in 2035 is met by fly ash, and 70% of potential demand from wallboard production is met by FGD gypsum. Only about 25% of potential demand from fill applications is met however, with most of that 25% being met by fly ash and other residues. Concrete and wallboard represent higher value end uses than fill applications; as a result, the model prefers to meet most of the demand from these end uses before diverting CCR to lower value fill applications. Furthermore, potential demand for CCR in fill applications dwarfs demand from the other two end uses (see Figure 2), so even large quantities of beneficial use in fill applications correspond to a small percentage of total demand.

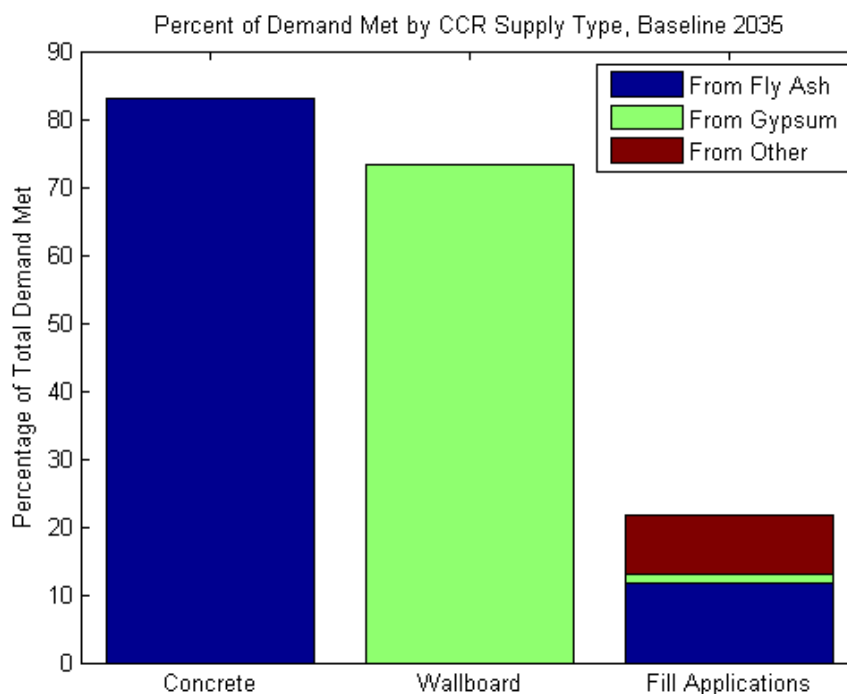


Figure 15. Percentage of Potential Demand Met by CCR Type, Baseline scenario for 2035.

Results for the Subtitle C Worst Case scenario are given in Figure 16. The Subtitle C Worst Case scenario sees a modest increase in dry-handled CCR supply and a sharp decrease in potential CCR demand relative to the baseline. As a result, the percentage of CCR demand met rises significantly for wallboard production and fill applications. Almost all demand for wallboard production is met in the worst case scenario, and the percentage of potential demand met for fill applications doubles to about 50%. The percentage of concrete demand met stays constant, however, since beneficial use in the baseline is limited by prohibitively long shipping distances, rather than supply or demand constraints.

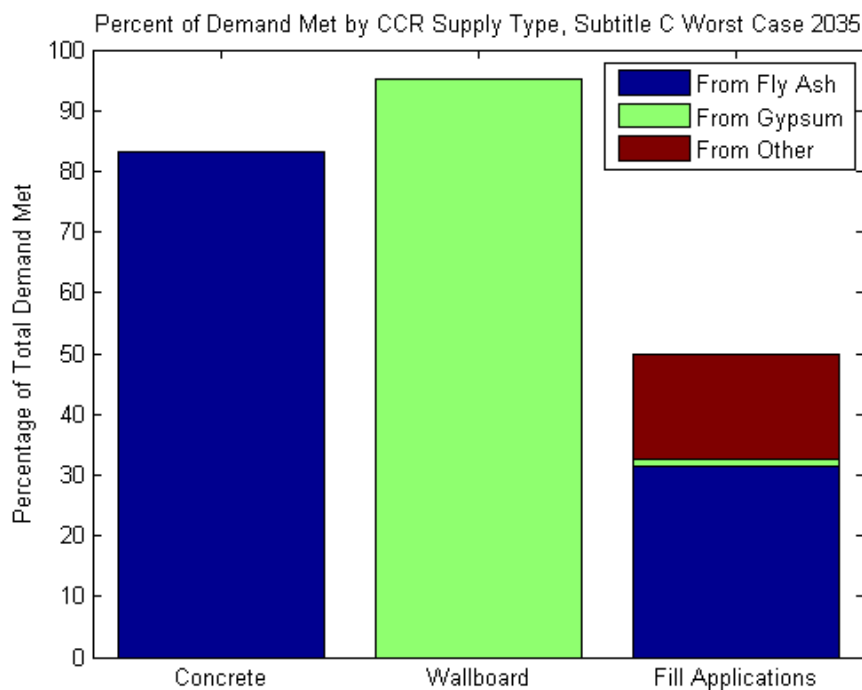


Figure 16. Percentage of Potential Demand Met by CCR Type, Subtitle C Worst Case scenario for 2035.

Figure 17 shows that the percentage of potential demand met in the Subtitle C Optimistic scenario matches the values produced for the baseline scenario very closely. The Subtitle C Optimistic scenario assumes no stigma effect, but a modest increase in dry handled CCR supply. Figure 8 shows that total beneficial use for concrete and wallboard production in the Subtitle C Optimistic scenario matches that in the baseline, and that the increase in supply leads to an increase in fulfilled demand from fill applications. Results from Subtitle D and Subtitle D Prime create a similar picture, with slightly smaller increases in the percentage of demand from fill applications being met.

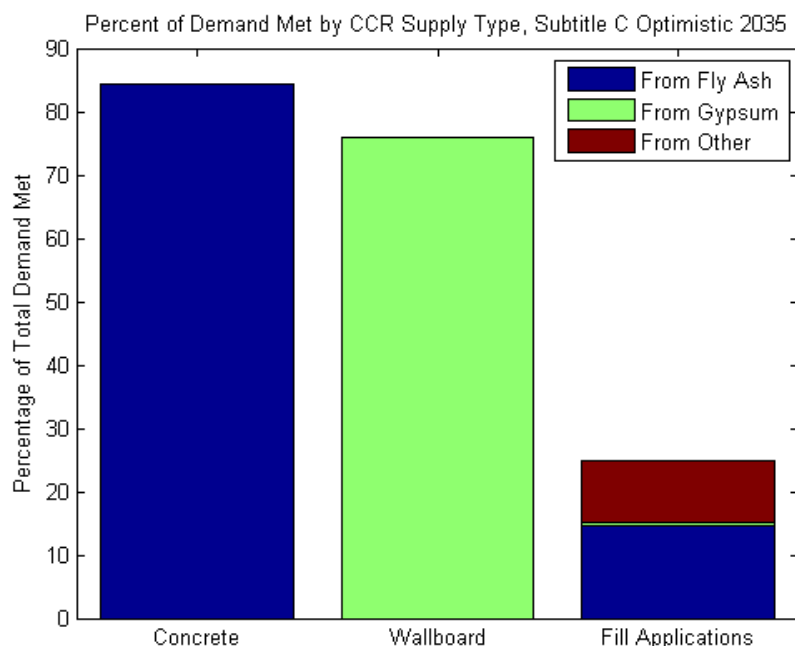


Figure 17. Percentage of Potential Demand Met by CCR Type, Subtitle C Optimistic scenario for 2035.

3.4 Spatial Results

In addition to changes in total levels of beneficial use, different policy scenarios can lead to geographic shifts in beneficial use. The stigma effect, in particular, varies highly across states, and the impacts of limiting or restricting beneficial use in particular states can spread to surrounding areas. The following figures show how spatial patterns of beneficial use would be impacted under different policy scenarios. Figure 18 shows the spatial distribution of demand for fly ash used in concrete production for the baseline scenario in the year 2035. The blue background indicates the percentage of potential concrete demand met at the county level throughout the United States, and the red circles are overlaid to indicate the percentage of fly ash supply used at the power plant level. (Note that power plants are symbolized by the percentage of fly ash beneficially used for either concrete or fill applications, not just concrete production.) In the baseline scenario in 2035, the vast majority of the country meets at least 75% of its demand for fly ash in concrete, with much of the country satisfying 100% of demand. The northeast, Pacific coast, northwest, and parts of Texas are the only regions with significant unmet demand for fly ash in concrete applications. Power plants with unused fly ash supply (indicated by lighter circles) are generally located in areas where demand is totally saturated, due to competition from other local supplies and/or limited total demand levels.

Fly Ash Supply and Concrete Demand Percentages Baseline, 2035

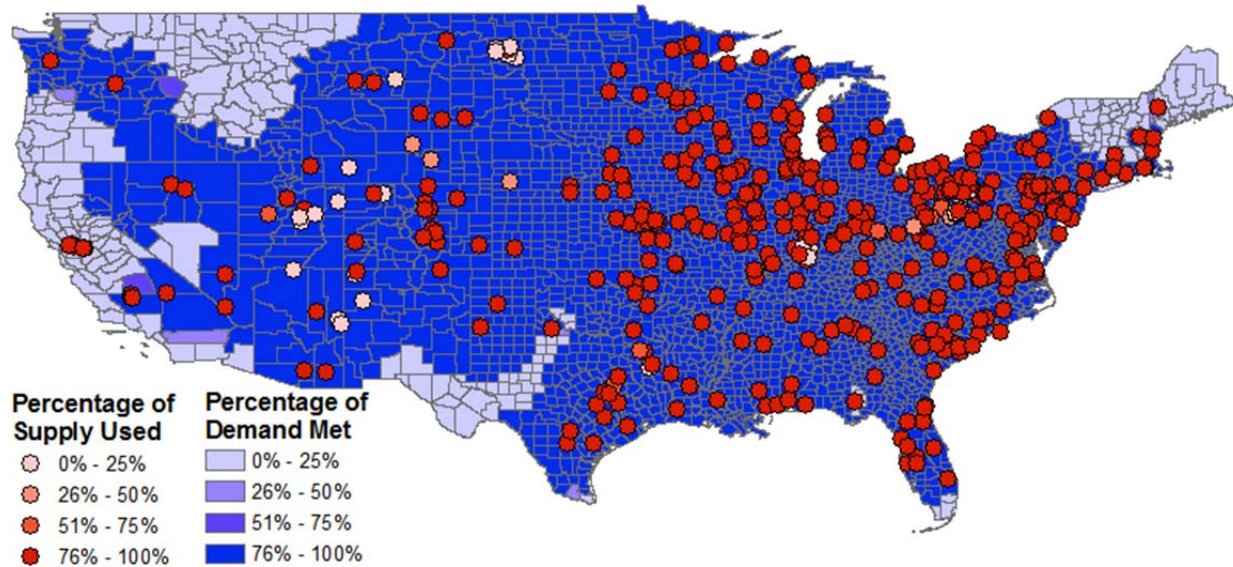


Figure 18. Percentages of Fly Ash Supply Used and Potential Concrete Demand Met for Baseline, 2035.

Figure 19 provides similar results for the Subtitle C Worst Case policy scenario. Comparing the results in Figure 19 to those in Figure 18 clearly shows the impact of the stigma effect assumed in the Worst Case scenario. Demand for fly ash in concrete production completely disappears in populous states such as Texas, Florida, Pennsylvania and others, most of which saw all of their demand for fly ash met in the baseline scenario. Eliminating beneficial use of fly ash in concrete production in these states does have some minor spillover effects; some areas of the Northeast and the Pacific Northwest do see an increase in beneficial use relative to the baseline scenario. However, restricting beneficial use more commonly leads to stranding fly ash supplies, illustrated by the white dots found throughout Texas, Florida, much of the Midwest, and the Rocky Mountain states. Many of these dots are red in Figure 18, indicating beneficial use of fly ash from these plants was high in the baseline scenario but drops off in the Subtitle C Worst Case scenario.

Fly Ash Supply and Concrete Demand Percentages Subtitle C Worst Case, 2035

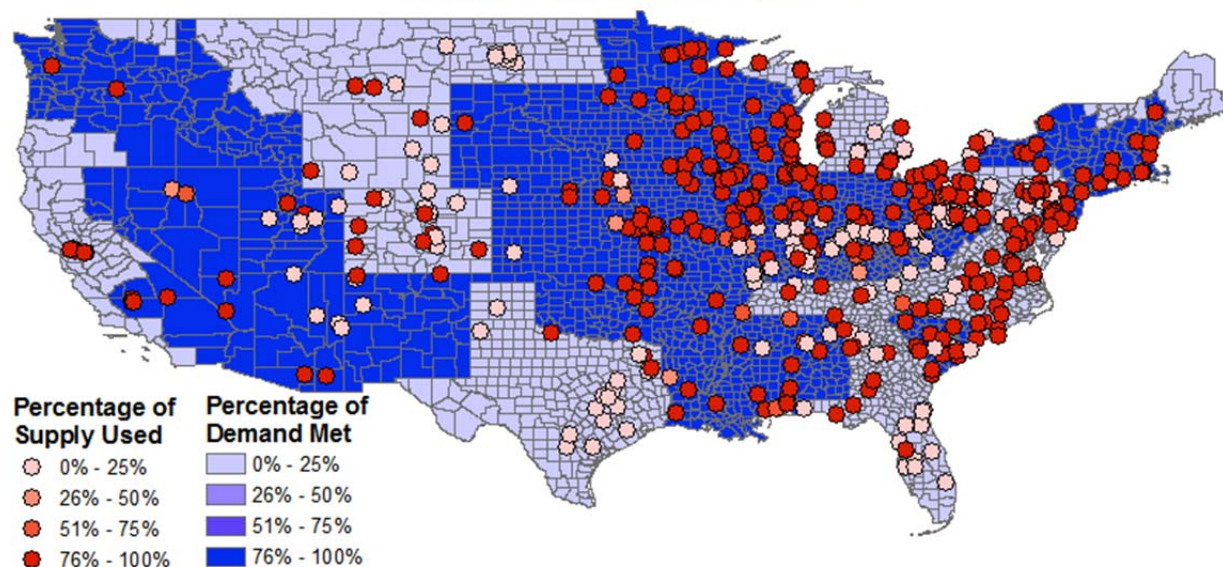


Figure 19. Percentages of Fly Ash Supply Used and Concrete Demand Met for Subtitle C Worst Case, 2035.

Figure 20 shows that the spatial distribution of the beneficial use of fly ash under the Subtitle C Optimistic policy scenario does not differ significantly from the spatial distribution in the baseline scenario. Figure 8 shows that the additional CCR beneficial use in this scenario leads primarily to an increase in beneficial use in fill applications, and that beneficial use of fly ash in concrete production remains almost unchanged. However, there is more overall CCR supply compared to the baseline, leading to a slight increase in unused fly ash in certain areas, particularly along the Ohio River.

Fly Ash Supply and Concrete Demand Percentages Subtitle C Optimistic, 2035

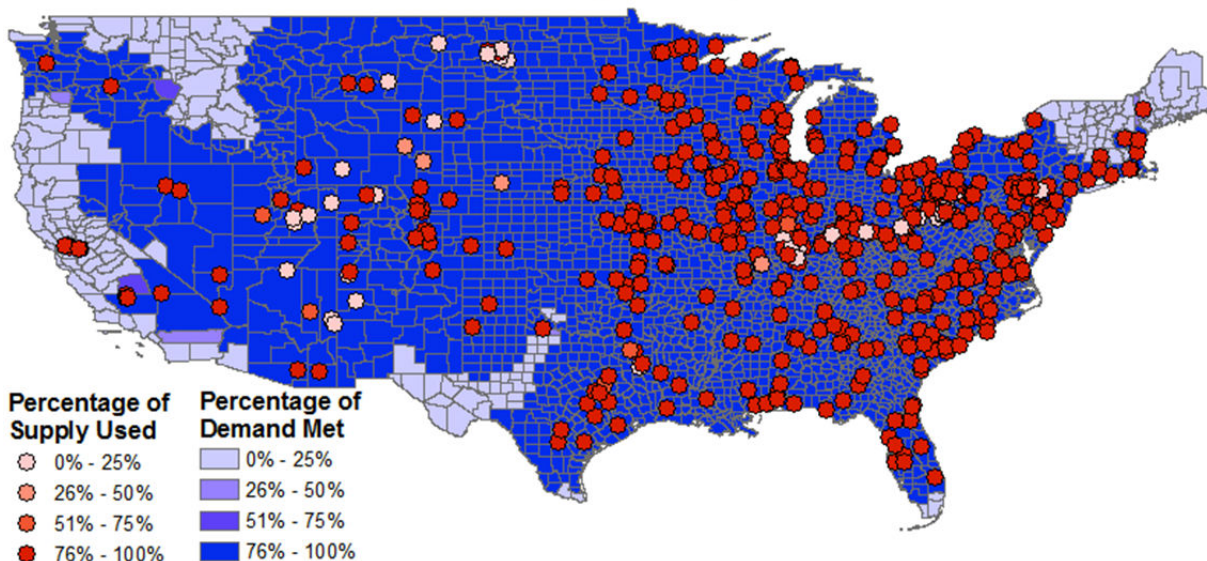


Figure 20. Percentages of Fly Ash Supply Used and Concrete Demand Met for Subtitle C Optimistic, 2035.

Different policy scenarios could also lead to differences in the spatial distribution of beneficial use in fill applications. Figure 21 shows the spatial distribution of beneficial use of fill for the baseline scenario in 2035. Like the figures shown above, the shaded background illustrates the percentage of total demand from fill applications that is met at the county level, with darker shades of green corresponding to increased percentages of demand fulfillment. The red circles symbolize power plants, with darker shades of red corresponding to higher percentages of total CCR beneficial use. In the baseline scenario, CCR beneficial use for fill applications is highly localized. There are only a few large regions that see more than 75% of their demand met: a large group of counties along the Ohio River, an area of east Texas, and a large region near the Rocky Mountains. There are a number of other small regions with high levels of beneficial use, but demand for fill applications dwarfs supply of CCR at the national level, so most power plants can find outlets for their supply in relatively close proximity to their facilities.

Total CCR Supply and Fill Application Demand Percentages Baseline, 2035

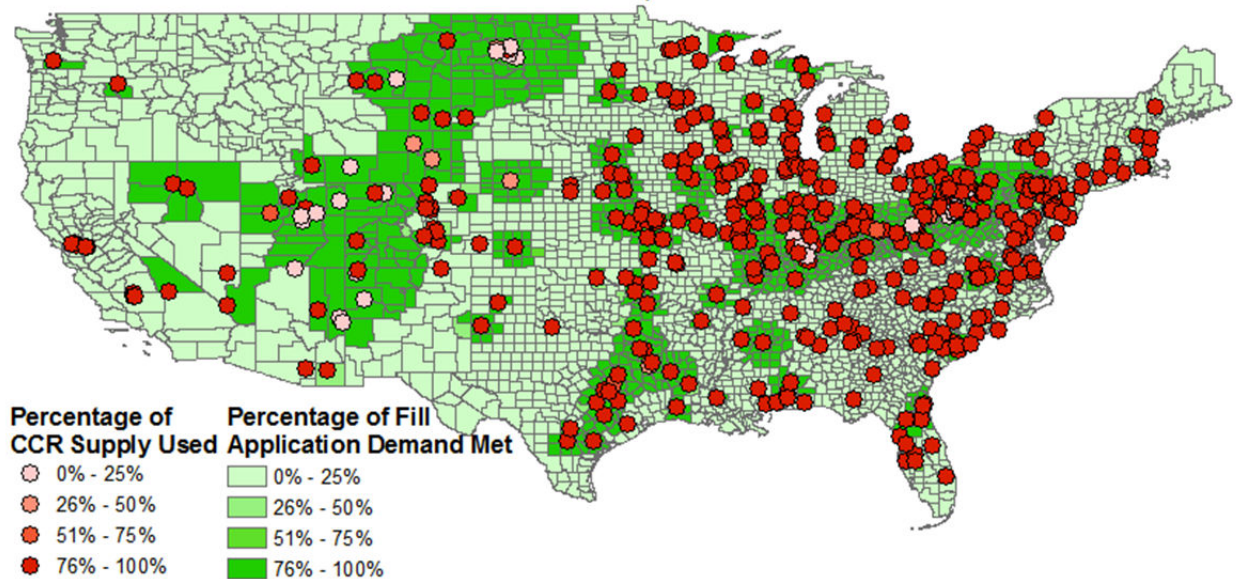


Figure 21. Percentages of Total CCR Supply Used and Fill Application Demand Met for Baseline, 2035.

Figure 22 shows that the results from the Subtitle C Worst Case scenario look much different from the results in the baseline. There are two factors impacting the distribution of demand in this scenario: the restriction of beneficial use in the 14 ACAA states, and the removal of residential fill applications across the country. The restriction of beneficial use in the ACAA states leads to the disappearance of beneficial use for fill applications in states such as Texas, Colorado, Wyoming and others that featured significant levels of beneficial use in the baseline scenario, and in some cases, spillover into adjacent states. The removal of residential fill applications reduces demand across the board, forcing power plants to look further for customers and leading to beneficial use patterns that aren't as localized as they are in the baseline scenario. The net effect is beneficial use that not only shifts, but also spreads out, as evidenced by the widespread beneficial use throughout the Midwest and parts of the Southeast. These changes also lead to an increase in the percentage of unused CCR, in particular in Texas and Florida, both of which are assumed to totally restrict beneficial use of CCR.

Total CCR Supply and Fill Application Demand Percentages Subtitle C Worst Case, 2035

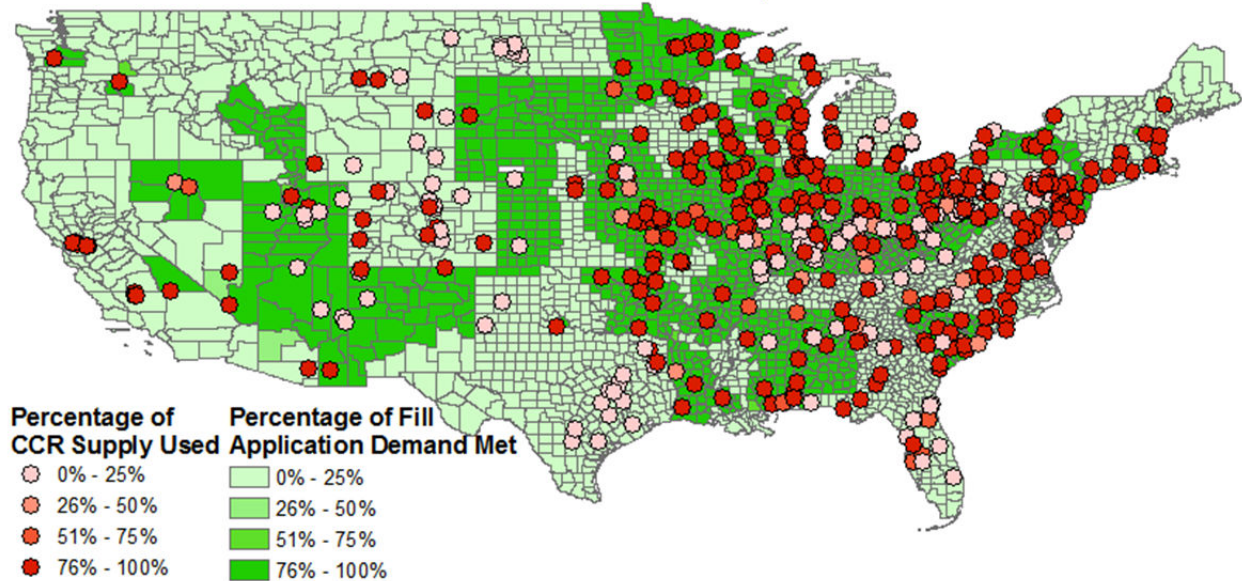


Figure 22. Percentages of Total CCR Supply Used and Fill Application Demand Met for Subtitle C Worst Case, 2035.

At the other end of the spectrum, results for the Subtitle C Optimistic policy scenario show a similar spatial distribution as the results for the baseline. Figure 23 shows that beneficial use in fill applications is still common throughout much of the Midwest and the Rocky Mountain states, just like in the baseline scenario. So, while the overall level of beneficial use increases for this scenario (see Figure 8), this policy scenario would probably not significantly alter the spatial distribution of beneficial use compared to the baseline.

Total CCR Supply and Fill Application Demand Percentages Subtitle C Optimistic, 2035

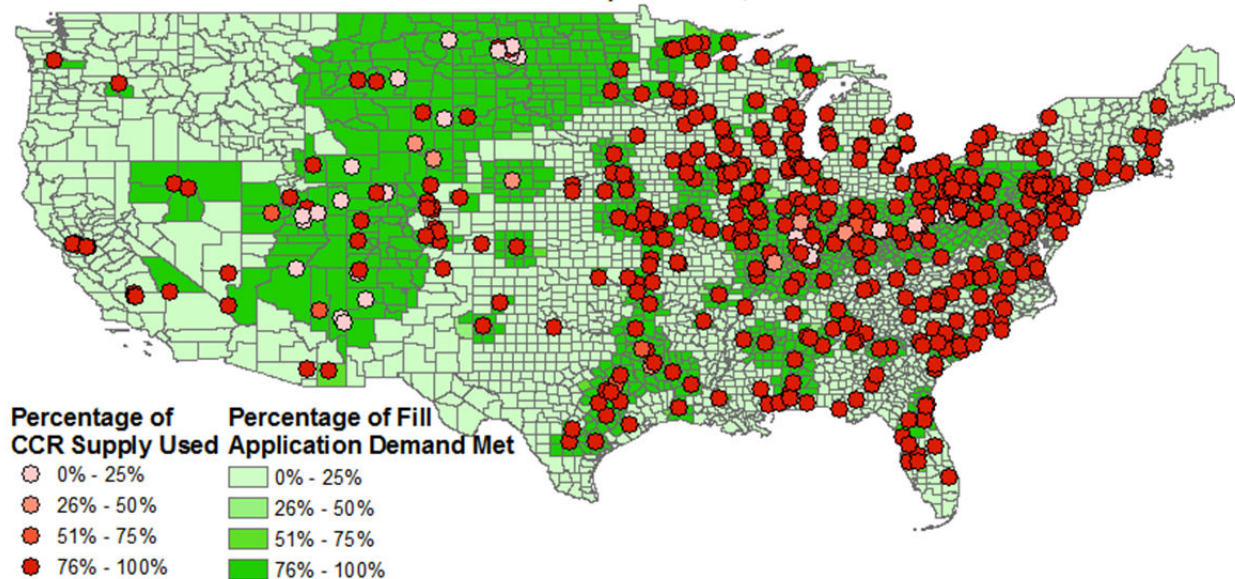


Figure 23. Percentages of Total CCR Supply Used and Fill Application Demand Met for Subtitle C Optimistic, 2035.

3.5 Shipping Distances

Policy scenarios that increase the supply of CCR and/or decrease the demand for CCR can force power plants to look further for demands, leading to longer shipping distances for the beneficial use of CCR. Figure 24 provides cumulative distribution functions for the shipping distances resulting from each scenario. (Curves shown in Figure 24 represent shipments of all types of CCR to all potential end uses.) Curves for the baseline, Subtitle C Optimistic, Subtitle D, and Subtitle D Prime scenarios are effectively identical, showing that the shipping profile is largely unaffected by scenarios that increase the overall level of beneficial use. However, both the Subtitle C Best Estimate and Subtitle C Worst Case scenarios have distributions that are shifted right from the baseline, indicating that these scenarios lead to widespread increases in shipping distances required for CCR beneficial use.

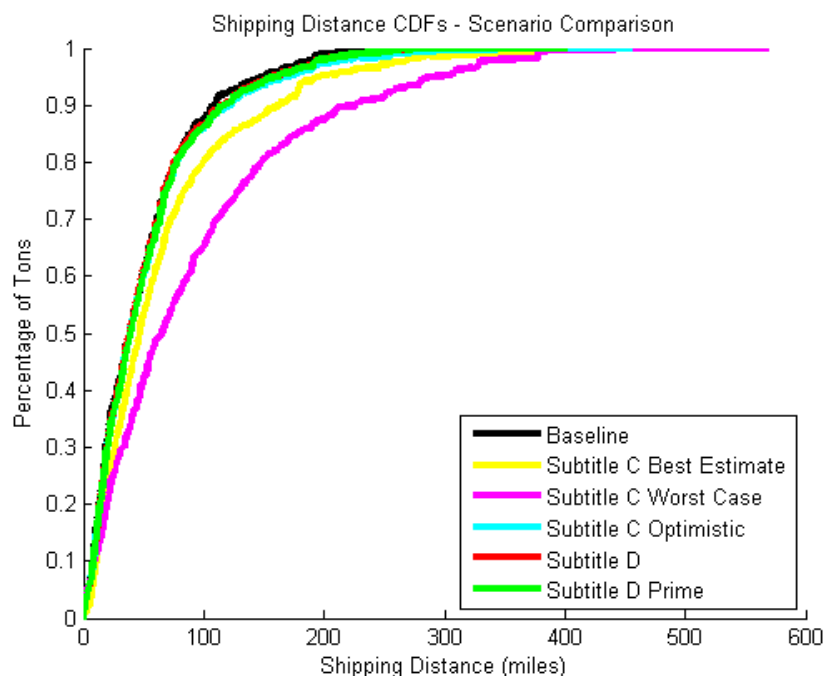


Figure 24. Shipping Distance Distributions, Scenario Comparison for 2035.

Shipping distances for different scenarios can be further examined by looking at CDFs for individual types of beneficial use. Figure 25 provides three CDFs for beneficial use in concrete, wallboard, and fill applications for the baseline scenario in 2035. Shipping distances are generally shortest for fill applications, where demand far exceeds supply, and power plants can find customers for their residues very close by. CCR used in concrete production and CCR used in wallboard production have similar shipping distance distributions, with the distribution for wallboard production showing more of a step pattern due to the small number of production sites that comprise the group of demands. For all three end uses, 90% of tons are shipped 150 miles or less from origin to destination.

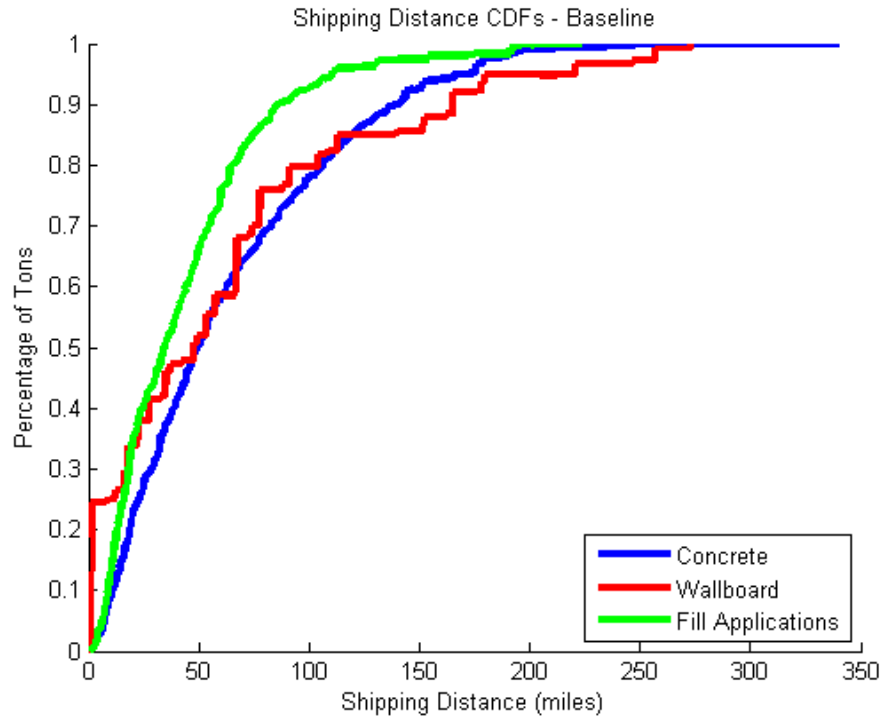


Figure 25. Shipping Distance Distributions, Baseline for 2035.

Figure 26 shows that the Subtitle C Worst Case scenario leads to much longer shipping distances than those in the baseline. The distribution for shipping distances for wallboard production is similar, but the distributions for both concrete and fill applications are shifted to the right, indicating longer overall distances. For instance, the median shipping distances for concrete and fill applications in baseline scenarios are roughly 50 and 30 miles, respectively. In the Subtitle C Worst Case scenario, median shipping distances for both of these end uses exceed 75 miles. Similarly, the 90th percentile distances in the baseline are 140 and 75 miles for concrete and fill applications, values that climb to almost 250 miles for the Subtitle C Worst Case. Figure 7 shows that the Subtitle C Worst Case policy scenario leads to significantly less beneficial use than the baseline. Based on the results shown in Figure 25 and Figure 26, this policy would lead to much longer shipping distances as well.

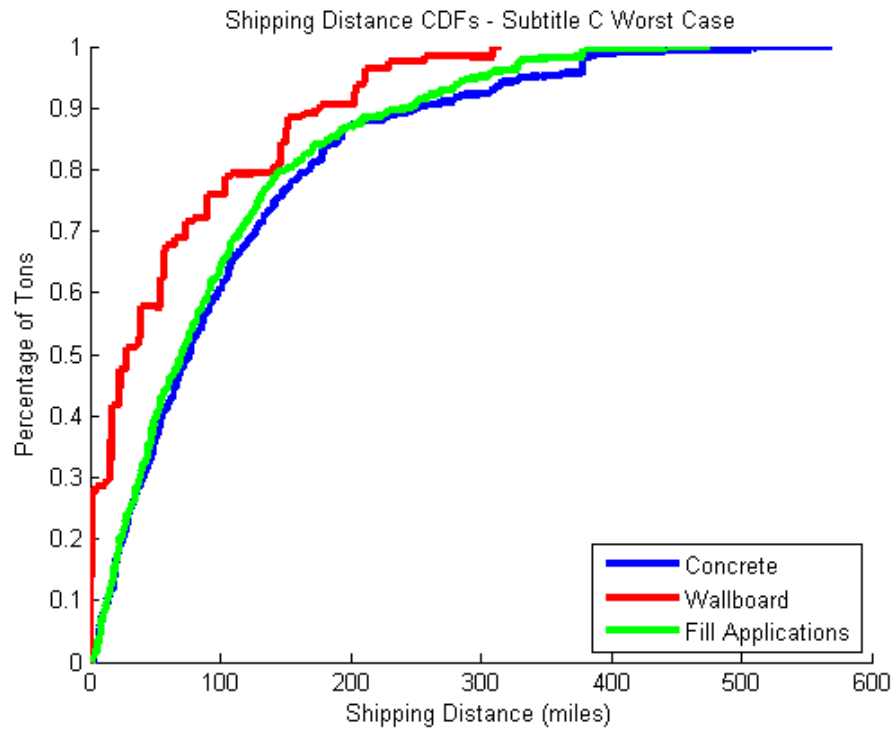


Figure 26. Shipping Distance Distributions, Subtitle C Worst Case for 2035.

4. Sub-attachment

4.1 Calibration Algorithm

Before analyzing the impacts of various policy scenarios, it was necessary to calibrate the model to the baseline values. Model calibration was conducted by introducing calibration parameters representing fixed costs for each type of CCR end use. More precisely, calibration was conducted by introducing parameters:

$$P_{cal}(n)$$

Where n is the set of potential CCR end uses (concrete production, wallboard production, and fill applications), and calculating new ‘calibrated’ costs equal to the original cost functions discussed above, plus the calibration parameter:

$$c_{cal}(i, j, m, n, P_{cal}(n)) = c(i, j, m, n) + P_{cal}(n)$$

Values for $P_{cal}(n)$ were then chosen to minimize the difference between the total beneficial use projected by the model (for the baseline scenario) and the total beneficial use estimated for each type of CCR end use for the baseline:

$$\text{Minimize } \sum_n abs \left(\left[\sum_m \sum_i \sum_j x^*(i, j, m, n, P_{cal}(n)) \right] - \text{Baseline}(n) \right)$$

Where $x^*(i, j, m, n, P_{cal}(n))$ denotes the optimal solution generated by the model as a function of the values of the calibration parameters, and $\text{Baseline}(n)$ represents the baseline values exogenously specified for total beneficial use in concrete production, wallboard production, and fill applications.

Choosing optimal values for $C_{cal}(n)$ that minimize the difference between the two baselines is a non-trivial problem. Due to time constraints and the lack of precision required for the solution, calibration parameters were selected using a simple iterative process combined with an approximation algorithm for the optimization model.

The model calibration algorithm begins by assuming all calibration parameters are set to zero. The algorithm then manually iterates over a discrete range of values of $P_{cal}(\text{concrete})$, selecting the value that minimizes the quantity shown above, representing the difference between the amount of beneficial use in the model and the amount specified exogenously, summed over all three potential end uses.

Based on this selected value for $P_{cal}(\text{concrete})$, the model then manually iterates over values of $P_{cal}(\text{wallboard})$, again selecting the value that minimizes the difference in projected beneficial use. Given these values for $P_{cal}(\text{concrete})$ and $P_{cal}(\text{gypsum})$, the model iterates over a discrete range of values for $P_{cal}(\text{fill applications})$ and selects the difference-minimizing value.

Given these values for $P_{cal}(n)$, the model then restarted from the beginning, iterating over values of $P_{cal}(concrete)$, since it is possible that nonzero values for $P_{cal}(n)$ would change the ‘optimal’ value of the first calibration parameter. The model then continued this process until the values of $P_{cal}(n)$ converged.

Depending on the specific scenario being modeled, a single run of the optimization model could take up to twenty minutes, giving this ‘brute force’ calibration algorithm a prohibitively long runtime. Therefore, an approximation algorithm was used in place of the actual optimization model within the calibration model. The approximation algorithm was essentially a greedy algorithm that selected shipments with the greatest benefit up to the point where either a) CCR supplies were exhausted, b) CCR demands were met, or c) shipments no longer resulted in a net benefit.

The algorithm begins by setting the supply and demand quantities (which will be updated during the approximation algorithm) at each location equal to their initial values:

$$S_{update}(i, m) = S(i, m)$$

$$D_{update}(j, n) = D(j, n)$$

Given a set of values for $P_{cal}(n)$, the approximation algorithm sorts the cost coefficients $c_{cal}(i, j, m, n, P_{cal}(n))$ in ascending order and begins with the first element in the list. Since these coefficients represent the per-ton cost for beneficial use, the first element in the list represents the most socially beneficial shipment option. (Note that this term generally represents a shipment that travels a very short distance and incurs a significant cost reduction due to avoided CCR disposal or product purchasing cost.)

If the value of the first coefficient in the list is negative, then the approximation algorithm ships as much of that type of CCR from supply i to demand j as possible, increasing that value up to the point where it equals the total supply available at supply i or the total potential demand at demand j :

$$x^*(i, j, m, n, P_{cal}(n)) = \min(S_{update}(i, m), D_{update}(j, n))$$

The algorithm then updates the remaining supply and unmet demand at the pair of impacted sites by subtracting the assigned quantity from both updated quantities:

$$S_{update}(i, m) = S_{update}(i, m) - x^*(i, j, m, n, P_{cal}(n))$$

$$D_{update}(j, n) = D_{update}(j, n) - x^*(i, j, m, n, P_{cal}(n))$$

The algorithm then steps down the list to the second smallest coefficient (or the shipment options with the second largest cost reduction) and ships as much of that type of CCR from supply i to demand j as possible based again on the supply and demand totals at that pair of sites. The algorithm continues moving down the list (to shipments with decreasing benefit), assigning CCR beneficial use levels equal to the minimum of the remaining supply and demand values, until it reaches shipments that incur a net cost, at which point it terminates.

This calibration algorithm was run separately for each year examined in the analysis, running from 2013 to 2035, to generate separate sets of calibration parameters matching the expected growth in beneficial use.

4.2 Calibration Results

Figure 27 shows the calibration parameters determined by the algorithm described above.

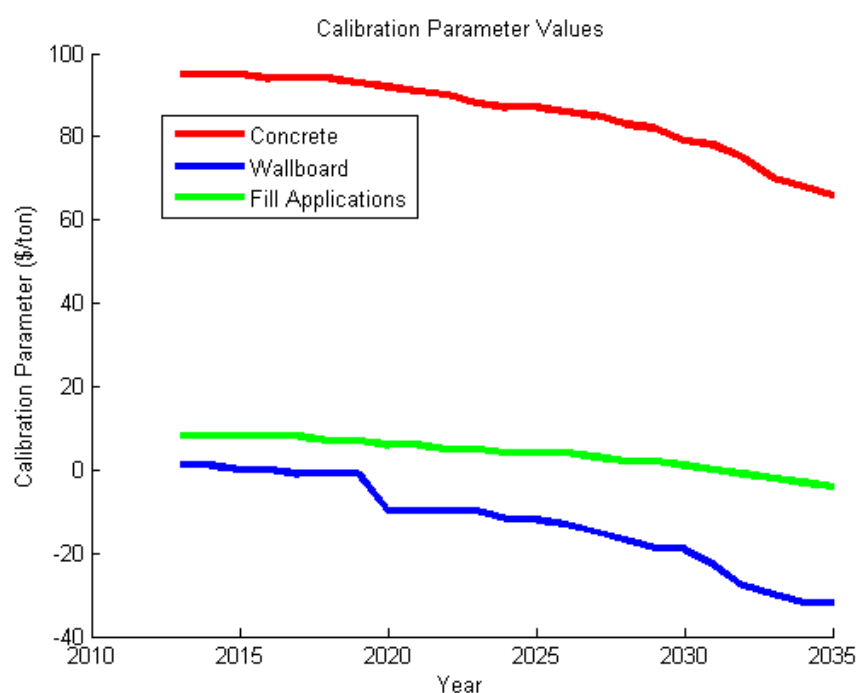


Figure 27. Calibration parameters for concrete, wallboard, and fill applications as a function of year.

Figure 28 shows total beneficial use for concrete, wallboard, and fill applications for both the model baseline and the exogenously specified baseline. While the approximation algorithm used to calibrate the model may not solve for the optimal shipments, it provides a fairly accurate estimate of the total beneficial use of each type that the optimization model will produce, and the overall estimates produced by the model match those in the exogenously specified baseline very closely.

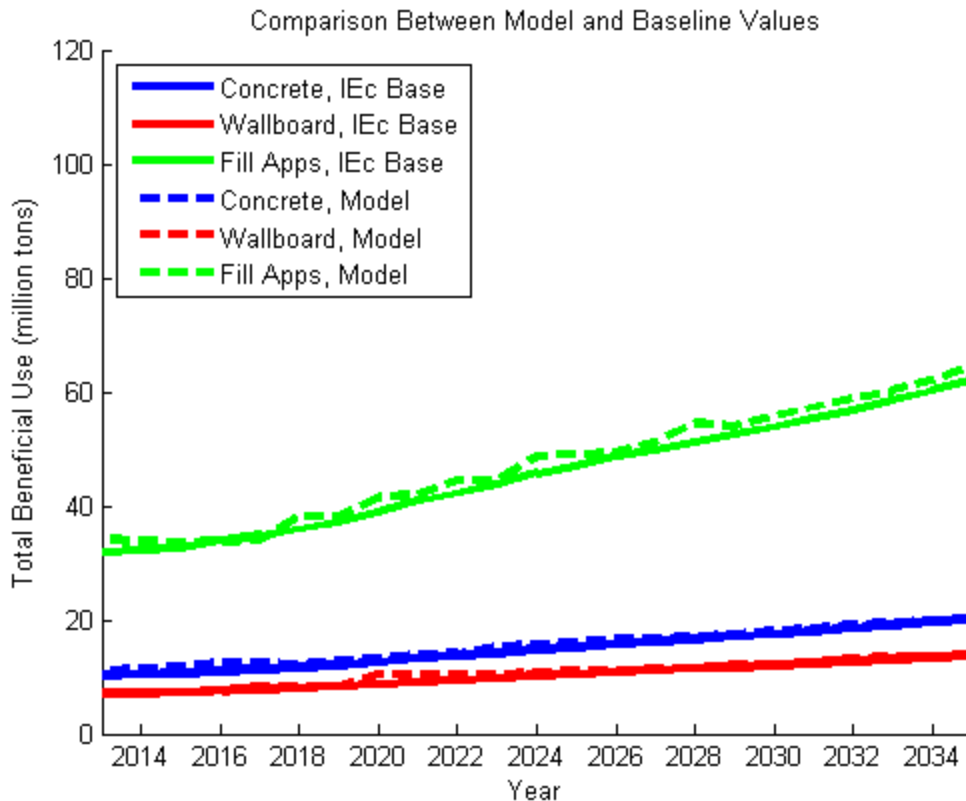


Figure 28. Comparison of total beneficial use by end use type, Industrial Economics baseline and calibrated model results.

4.3 Sensitivity Analysis – Concrete Prices

All policy scenarios modeled here show significantly more CCR going to fill applications than concrete production. Due to concerns about underestimating CCR use in concrete production (and overestimating CCR use in fill applications) due to potential changes in concrete prices, sensitivity analyses were run to examine the impact of increasing the avoided concrete price. Higher avoided concrete prices would make concrete production a more attractive end use for CCR, potentially shifting beneficial use more heavily toward concrete.

Figure 29 shows the results of this sensitivity analysis on the Subtitle C Best Estimate scenario. Curves are provided for the amount of beneficial use going to concrete production for the base case scenario, as well as for cases ranging from a \$5/ton to a \$50/ton increase in avoided concrete price to a \$50/ton increase. Two main trends can be seen from Figure 29. First, increasing the avoided concrete price does increase beneficial use of CCR in concrete production, but the largest increases in beneficial use result from the initial \$5/ton increase. Additional increases in the concrete price continue to increase beneficial use, but at a declining rate. Second, increases in beneficial use resulting from the increase in concrete price decline during future years. As the model approaches 2035, the amount of beneficial use projected in the base case approaches the total demand from concrete production. As a result, increasing the

avoided concrete price has less of an impact, since the demand that remains unmet in the base case in these later years is much less.

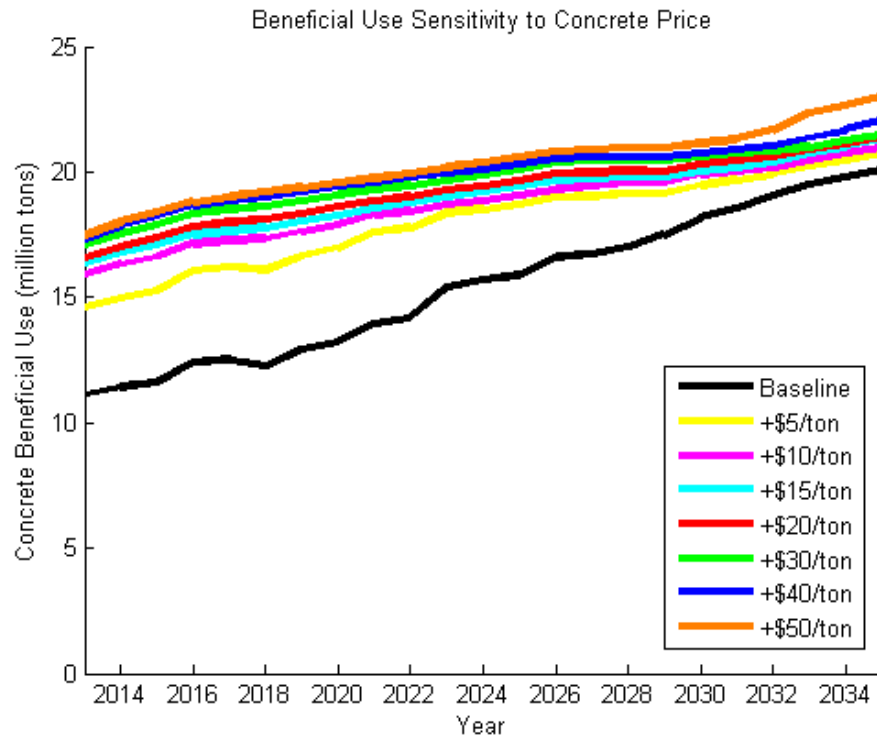


Figure 29. Sensitivity Analysis Results for Increasing Concrete Price.

ATTACHMENT 2 TO APPENDIX S:

*Fraction of Recent Nationwide CCR Structural Fill Beneficial Use
Applications Which May Be Classified as “Large Scale”*

Prepared by:

Mark Eads, Economist & Rachel Alford, Program Analyst
EPA Office of Resource Conservation & Recovery

October 27, 2011

Findings

- Based on the method and data presented below, the U.S. average percentage of coal combustion residual (CCR) beneficial use (BU) “structural fill” applications which may be classified as “large scale” is:
 - 7% of all annual CCR “structural fill” sites may be classified as “large scale” sites.
 - 28% of all annual CCR “structural fill” tonnages may be associated with the “large scale” sites.
- 13 of 50 (24%) state governments appear to have intentional or unintentional restrictions on “large scale” CCR structural fill (IA, IL, IN, MO, NC, ND, NE, OH, PA, TN, TX, VA, WY).
- Extrapolating these findings nationwide to the 25 states with known CCR structural fill sites – after subtracting the 13 states with apparent “large scale” restrictions -- produces an estimate of **1.407 million tons “large scale” CCR structural fill per year as of 2009 in 12 states (CO, DE, GA, KS, KY, MN, MS, NJ, NM, SC, WI, WV).**

Method

The above findings are based on analyses built upon the following three data sets presented below

Data Set 1: North Carolina Database on Recent CCR Structural Fill Sites – Case Example

- NC’s CCR structural fill sites database provides per-site CCR cubic yards and/or tonnage data for 62 of 71 CCR structural fill sites spanning 1989-2009.
- EPA-ORCR was unable to discover site-by-site detailed CCR structural fill databases for other states, so the NC database constitutes a single “case example” in this analysis. Thus, the implicit assumption in this analysis is that the size distribution of NC’s CCR structural fill sites is representative of other states with CCR structural fill sites.
- Exhibit 1 below displays a size frequency distribution of the per-site tons (or cubic yards) for NC’s CCR structural fill sites. This distribution is based on the site-by-site NC data displayed in Exhibit 2. There is a large size gap between most sites clustered between 1 and 250,000 tons or cubic yards, compared to only four sites above 450,000. Thus, this analysis uses >450,000 as “large scale” indicator. In addition, this analysis includes any CCR fill site in NC involving a sand or gravel pit as a “large scale” site.
- Relative to these two “large scale” indicators, the NC data show that:
 - 7% of CCR structural fill sites in NC may be classified as “large scale” sites (i.e., $5 / 71 = 7\%$).
 - 47% of CCR structural fill tonnage for NC may be classified as “large scale” (i.e., $2,500,019$ total tons for 5 “large scale” CCR structural fill sites) / ($5,365,279$ total tons for all 71 NC sites).

Data Set 2: State-by-State CCR Structural Fill Regulations

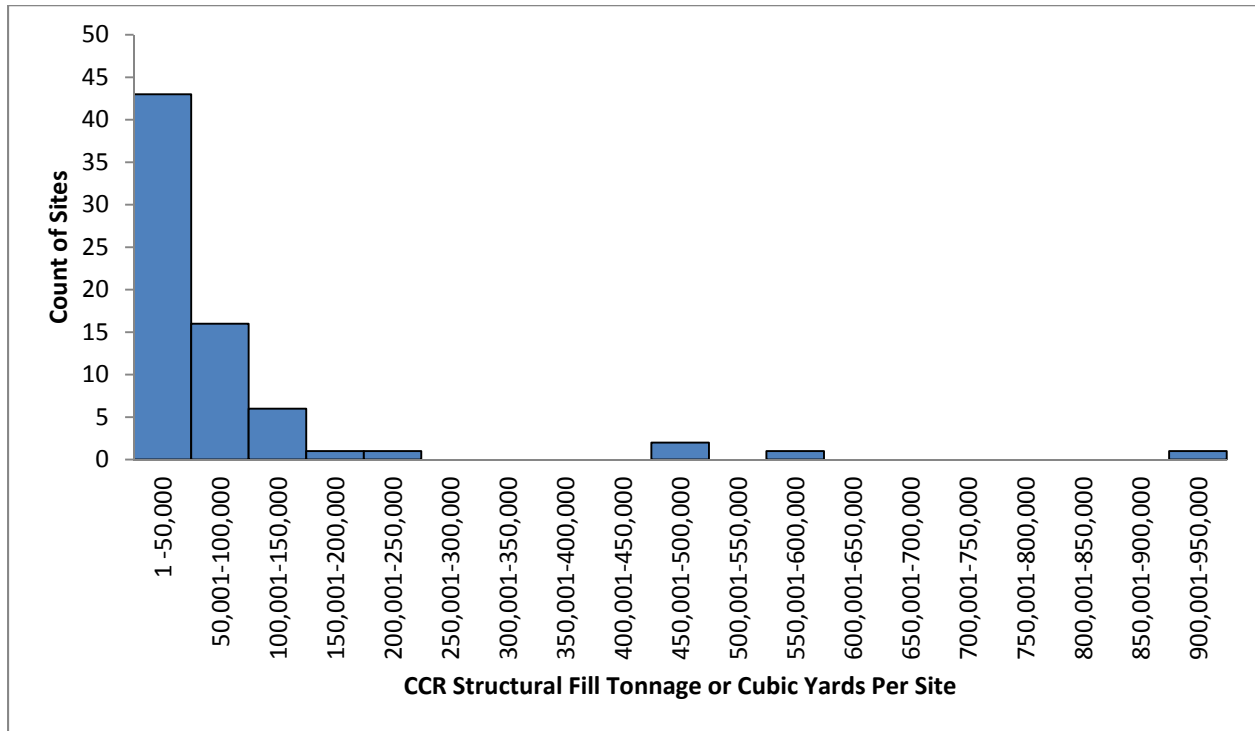
- Exhibit 3 displays the 25 states which have CCR structural fill operations as of 2010 (CO, DE, GA, IA, IL, IN, KS, KY, MN, MO, MS, NC, ND, NE, NJ, NM, OH, PA, SC, TN, TX, VA, WI, WV, WY).
- Based on EPA-ORCR review of existing state government regulations in these 25 states as displayed in Exhibit S2-4, 13 state governments appear to have, either intentionally or

unintentionally, restrictions or prohibitions on “large scale” CCR structural fill (IA, IL, IN, MO, NC, ND, NE, OH, PA, TN, TX, VA, WY). Criteria for this interpretation were presence of engineering/design restrictions for fill applications.

Data Set 3: State-by-State Annual Tonnage of CCR Structural Fill

- Exhibit 5 displays state-by-state total CCR beneficial use tonnage data (source: 2009 ACAA).
- On a nationwide total basis, 16% of total CCR beneficial use tonnage involves for CCR structural fill applications (i.e., (2009 ACAA Structural Fills/Embankments 8,856,396 short tons) / (2009 ACAA Total CCPs Used 55,642,011 short tons) =16% of BU used for “structural fill/embankments”).
- Multiplying the 8.856 million tons (2009) CCR beneficial use tonnage for the 25 states which have CCR structural fill applications -- after subtracting the 13 states which may have CCR “large scale” fill restrictions -- by the 47% “large scale” fill result based on the NC data, produces a nationwide estimate of 16% “large scale” CCR structural fill (i.e., estimated 1,407,222 short tons “large scale” CCR structural fill) / (2009 ACAA 8,856,395 short tons US total CCR structural fill/embankments).

Exhibit S-2-1:
Size Distribution of North Carolina's CCR Structural Fill Sites (1989-2009)



Source: EPA-ORCR analysis of the North Carolina CCR structural fill database (1989-2009).

Exhibit S-2-2 Inventory of CCR Structural Fill Sites in North Carolina (1989-2009)							
C	D	E	F	G	H	I	J
Project	Description	Location	Coal Ash Source	Amount of Ash Used	Quantity Assigned by EPA-ORCR based on Column G	Quantities w/Average Assigned by EPA-ORCR to Blanks in Column H	Year Begun
Thompson Farm	Utilizing ash from UNC-Chapel Hill power plant on a one-time basis to determine suitability of material as a substitute for commercial lime	One mile off Hwy 54 along Phillips Chapel Church Road	UNC-Chapel Hill cogeneration facility	600 tons	600	600	1992
Swain County Airport	Additional hangar and parking space	Long Beach Road, Oak Island	Southport Cogentrix	30,000 cubic yards	30,000	30,000	1994
Swain County Airport	Base for farm access road	Winnabow	DuPont Cape Fear	10,000 cubic yards	10,000	10,000	1998
Swain County Airport	Reclaim dirt borrow pit and base for access road	1 mile west of S.R. 1410 and S.R. 1409	DuPont Cape Fear	30,000 cubic yards	30,000	30,000	1999
Swain County Airport	Elevating roads through hunting lands	Bolivia	DuPont DAK Americas in Leland, N.C.	28,000 cubic yards/22,000 tons	28,000	28,000	2005
Southport Community Center	Subgrade for floor restoration in municipal gym	211 N. Atlantic Ave., Southport	Southport Cogentrix	560 cubic yards	560	560	1996
Swain County Airport	Filling an abandoned NC Department of Transportation borrow pit for pasture land	Just north of S.R. 1410	Cape Fear DuPont	30,000 cubic yards	30,000	30,000	1998
Swain County Airport	Filling depression	Kannapolis	plant's own boilers	13,000 tons	13,000	13,000	1994

Exhibit S-2-2
Inventory of CCR Structural Fill Sites in North Carolina (1989-2009)

A	B	C	D	E	F	G	H	I	J
Row	County	Project	Description	Location	Coal Ash Source	Amount of Ash Used	Quantity Assigned by EPA-ORCR based on Column G	Quantities w/Average Assigned by EPA-ORCR to Blanks in Column H	Year Begun
			storage tanks were located and providing a base for additional parking and recreation areas						
9	Catawba	Jeten Property	Filling 7.9 acre construction site for commercial office and warehouse	7836 N.C. Highway 150 East, Mooresville, NC	Duke Marshall plant	85,000 cubic yards/102,000 tons	102,000	102,000	2001
10	Catawba	Marshall Steam Station Road	Service road at power plant	Marshall Steam Station	Duke Marshall plant	73,000 cubic yards	73,000	73,000	1997
11	Catawba	Marshall Steam Station Site	Fill for an industrial park	205.4 acres on the northwest side of the plant property, east of Steam Plant Road and Island Point Road	Duke Marshall plant	"Approximately 20,000 - 40,000 tons of ponded ash from the ash canal will be used annually in the on site structural fill. This represents approximately 4% to 8% by weight of the total annual quantity of ash to be used in	40,000	40,000	2009

Exhibit S-2-2
Inventory of CCR Structural Fill Sites in North Carolina (1989-2009)

A	B	C	D	E	F	G	H	I	J
Row	County	Project	Description	Location	Coal Ash Source	Amount of Ash Used	Quantity Assigned by EPA-ORCR based on Column G	Quantities w/Average Assigned by EPA-ORCR to Blanks in Column H	Year Begun
						the on site structural fill project."			
12	Columbus	Airplane Landing Strip	Landing strip for small aircraft	Intersection of S.R. 1836 and S.R. 1838	Cogentrix Lumberton & Elizabethtown	9,500 cubic yards	9,500	9,500	1994
13	Craven	Cherry Point Rifle Range	Structural fill at Marine Corps Air Station Cherry Point rifle range impact berm	DOES NOT SPECIFY	not specified	not specified		65,629	2009
14	Cumberland	Boogle Bay Raceway	Structural fill to expand the raceway's parking area	US 401 North, Fayetteville	CogentrixLumberton, Elizabethtown, Kenansville	not specified		65,629	1990
15	Cumberland	Boogle Bay Phase II	2.6-acre structural fill for development	Highway 401, Linden	UNC-Chapel Hill, Duke University's plant in Durham, Burlington Industries in Wake County, Cargill in Fayetteville, Collins & Aikman Albemarle Plant, Corn Products Plant in Winston-Salem, Cone Mills Greensboro Plant	not specified		65,629	1992
16	Cumberland	Crowell Constructors	Fill at the site of an asphalt plant	5600 Murchison	Burlington Industries in Wake Forest, Corn	50,000 cubic yards	50,000	50,000	1992

Exhibit S-2-2
Inventory of CCR Structural Fill Sites in North Carolina (1989-2009)

A	B	C	D	E	F	G	H	I	J
Row	County	Project	Description	Location	Coal Ash Source	Amount of Ash Used	Quantity Assigned by EPA-ORCR based on Column G	Quantities w/Average Assigned by EPA-ORCR to Blanks in Column H	Year Begun
		Site		Road, Fayetteville	Products in Winston-Salem, Cone Mills in Greensboro, JP Stevens Plant in Wagram, Philip Morris US in Concord				
17	Cumberland	Taylor Mine Site	Reclaiming an old sand pit and providing a site for a warehouse and/or storage buildings on agricultural land	US Hwy 401 North near the Cumberland-Harnett County border	UNC-Chapel Hill, Cogentrix Elizabethtown, Kenansville, Lumberton & Southport, Burlington Industries in Raeford	32,750 cubic yards	32,750	32,750	2001
18	Duplin	Kilpatrick Farms	Fill for building pads for concrete-floored livestock pens	2 miles south of Kenansville on Hwy 11	Cogentrix plant in Lumberton, Elizabethtown & Kenansville	38,000 cubic yards	38,000	38,000	1994
19	Duplin	Kilpatrick Farms II	Expansion of earlier livestock pen project	2 miles south of Kenansville on Hwy 11	same 3 Cogentrix plants	9,700 cubic yards	9,700	9,700	1995
20	Durham	Duke Science Center	Fill for science research center	Duke University West Campus, Durham	Duke University's power plant	5,000 tons	5,000	5,000	1992
21	Edgecombe	Fountain Industrial	Fill for construction of industrial park	SR 1403, Rocky Mount	Cogentrix plants, Chapel Hill cogen	not specified		65,629	1989

Exhibit S-2-2
Inventory of CCR Structural Fill Sites in North Carolina (1989-2009)

A	B	C	D	E	F	G	H	I	J
Row	County	Project	Description	Location	Coal Ash Source	Amount of Ash Used	Quantity Assigned by EPA-ORCR based on Column G	Quantities w/Average Assigned by EPA-ORCR to Blanks in Column H	Year Begun
		Park							
22	Forsyth	Tobaccoville Project	Fill for industrial site adjacent to RJ Reynolds' Tobaccoville Power Plant	Just north of Tobaccoville	RJReynolds Tobaccoville, Whitiker Park boiler	176,000 cubic yards	176,000	176,000	2001
23	Gaston	Allen Steam Station	Fill on the site of a power plant	South of the station's powerhouse adjacent to the Catawba River	Duke's Allen Plant	240,000 cubic yards	240,000	240,000	2009
24	Halifax	Halifax 301/BB Pierce 2	Fill for NC DOT's right-of-way along Hwy 301 adjacent to property owned by BB Pierce that also has a coal ash structural fill	Weldon	Roanoke Valley Energy, Weldon, NC	37,000 cubic yards	37,000	37,000	1996
25	Halifax	Halifax 301/BB Pierce 1	Fill for construction of 40,000 square foot warehouse	Weldon	Roanoke Valley Energy, Weldon, NC	80,000 cubic yards	80,000	80,000	1995
26	Halifax	Eastern Pride/Family Dollar	Fill at the intersection of Hwys 158 and 301	Along US 158 East in Weldon	Roanoke Valley Energy, Weldon, NC	10,000 cubic yards	10,000	10,000	2006
27	Halifax	Roanoke Rapids 1-95/NC 125	Fill for construction of NC 125 interchange on I-95	I-95 @ NC 125 interchange south of Roanoke Rapids	Cogentrix of Rocky Mount	5,000-7,000 cubic yards	7,000	7,000	1995

Exhibit S-2-2
Inventory of CCR Structural Fill Sites in North Carolina (1989-2009)

A	B	C	D	E	F	G	H	I	J
Row	County	Project	Description	Location	Coal Ash Source	Amount of Ash Used	Quantity Assigned by EPA-ORCR based on Column G	Quantities w/Average Assigned by EPA-ORCR to Blanks in Column H	Year Begun
28	Halifax	Old Coca-Cola Plant	Filling a 20' x 30' section of wetlands for proposed commercial development	North side of NC Hwy 301, north of intersection with NC Hwy 305, in Weldon	Cogentrix	122,498 cubic yards	122,498	122,498	1997
29	Halifax	J.S. Turner Lumber Yard	25-acre project to raise the elevation of a lumber drying yard	Weldon	Roanoke Valley Energy, Weldon, NC	495,000 cubic yards	495,000	495,000	1998
33	Halifax	Otis N. Vaughan Property	Reclaiming a 6-acre soil borrow pit for pasture land	4752 Highway 301	Roanoke Valley Energy, Weldon, NC	64,000 cubic yards	64,000	64,000	2008
31	Halifax	Wayne Long Mini Storage	11.5 acre structural fill to construct a storage facility's building pad	Along Hwy 125 in Halifax	Roanoke Valley Energy, Weldon, NC	111,524 cubic yards	111,524	111,524	2008
32	Halifax	Weldon Acceptance Facility	5.35-acre fill for a new waste acceptance facility and access road	North side of SR 1600 approx. .5 miles west of intersection with SR 1641 in Weldon	Roanoke Valley Energy, Weldon, NC	127,739 cubic yards	127,739	127,739	2003
33	Halifax	Weldon Fire Station	Fill for construction of new fire hall	U.S. Hwy 158 West, Weldon, NC (see scanned map)	Roanoke Valley Energy, Weldon, NC	6,689 cubic yards	6,689	6,689	1995
34	Iredell	Lake Norman	Airport expansion	Yager Road off SR 1494	Duke Marshall plant	6,200 cubic yards	6,200	6,200	1995

Exhibit S-2-2
Inventory of CCR Structural Fill Sites in North Carolina (1989-2009)

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Row	County	Project	Description	Location	Coal Ash Source	Amount of Ash Used	Quantity Assigned by EPA-ORCR based on Column G	Quantities w/Average Assigned by EPA-ORCR to Blanks in Column H	Year Begun
		Airport Lot 1							
35	Iredell	Lake Norman Airport Lot 2	Airport expansion, including construction of aircraft hangars and taxiways	Yager Road off SR 1494	Duke Marshall plant	8,000 cubic yards	8,000	8,000	1995
36	Iredell	Lake Norman Airport Lot 3	Construction of aircraft hangars and taxiways	Yager Road off SR 1494	Duke Marshall plant	3,355 cubic yards	3,355	3,355	1995
37	Iredell	Lake Norman Airport Lot 4 & 5	Airport expansion	Yager Road off SR 1494	Duke Marshall plant	6,800 cubic yards	6,800	6,800	1995
38	Iredell	Lake Norman Airport	Airport expansion	Yager Road off SR 1494	Duke Marshall plant	6,500 cubic yards	6,500	6,500	1995
39	Iredell	Lake Normal Airport	Airport expansion	Yager Road off SR 1494	Duke Marshall plant	8,182 cubic yards	8,182	8,182	1995
40	Iredell	Mezzepa Road Industrial Park	Development of Lots 2,3 & 4	Off NC Hwy 115	Duke Marshall plant	9,500 cubic yards	9,500	9,500	1995
41	Iredell	Mezzepa Road Industrial Park	Development of Lots 5 & 6	Off NC Hwy 115	Duke Marshall plant	9,500 cubic yards	9,500	9,500	1995
42	Iredell	Mezzepa	Development of Lots	Off NC Hwy	Duke Marshall plant	9,500 cubic	9,500	9,500	1995

Exhibit S-2-2
Inventory of CCR Structural Fill Sites in North Carolina (1989-2009)

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Row	County	Project	Description	Location	Coal Ash Source	Amount of Ash Used	Quantity Assigned by EPA-ORCR based on Column G	Quantities w/Average Assigned by EPA-ORCR to Blanks in Column H	Year Begun
		Road Industrial Park	7 & 8	115		yards			
43	Iredell	Mezzepa Road Industrial Park	Development of Lot 13	Off NC Hwy 115	Duke Marshall plant	9,500 cubic yards	9,500	9,500	1995
44	Iredell	Mezzepa Road Industrial Park	Development of Lot 14	Off NC Hwy 115	Duke Marshall plant	9,500 cubic yards	9,500	9,500	1995
45	Iredell	Brawley School Road Retail Site	Developing property for marketing	Intersection of US Hwy 21 and SR 1100	Duke Marshall plant	60,000 cubic yards	60,000	60,000	1995
46	Iredell	E.J. Simpson Property	Developing property for marketing	Between Bluefield Road and NC Hwy 150 near the I-77 Intersectiob	Duke Marshall plant	120,000 cubic yards	120,000	120,000	1997
47	Iredell	Terry K. Smith Hwy 150 Project	Developing property for marketing	Hwy 150 west of Mooresville	Duke Marshall plant	45,000 cubic yards	45,000	45,000	1994
48	Iredell	Port Village Business Park	Developing property for marketing	On NC Hwy 150 near the I-77 intersection	Duke Marshall plant	500,000 cubic yards, including 37,066 tons of pond ash	500,000	500,000	1996
49	Iredell	Race Park USA	13.72-acre fill site for commercial structures, a go-cart track and	7836 NC Hwy 150 East	Duke Marshall plant	45,000 cubic yards	45,000	45,000	2001

Exhibit S-2-2
Inventory of CCR Structural Fill Sites in North Carolina (1989-2009)

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Row	County	Project	Description	Location	Coal Ash Source	Amount of Ash Used	Quantity Assigned by EPA-ORCR based on Column G	Quantities w/Average Assigned by EPA-ORCR to Blanks in Column H	Year Begun
			parking areas						
50	Iredell	Rob Duckworth Site	Gasoline/convenience mart structure	Hwy 150 & Bluefield Road	Duke Marshall plant	60,000 cubic yards	60,000	60,000	2000
51	Mecklenburg	Huntersville Ford	Fill for a new car dealership	Hwy 21 just south of Gilead Road	Duke Marshall plant	70,000 cubic yards including 8,980 tons of pond ash	70,000	70,000	1999
52	Nash	Imperial Tobacco	While renovating former tobacco plant for use as an arts center and children's museum, builders demolished warehouse storage buildings, removed floor slabs and found a layer of coal ash approx. 4 inches deep; material removed and used to backfill the foundation of the planetarium; capped with concrete slab	North Church & McDonald Streets in Rocky Mount	Imperial Tobacco	225 cubic yards	225	225	2005
53	Nash	Englewood Baptist Church	Structural fill for building pad	One mile south of intersection of Winstead & Sunset Avenues	Cogentrix in Rocky Mount and Kenansville	8,000 cubic yards	8,000	8,000	1994

Exhibit S-2-2
Inventory of CCR Structural Fill Sites in North Carolina (1989-2009)

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Row	County	Project	Description	Location	Coal Ash Source	Amount of Ash Used	Quantity Assigned by EPA-ORCR based on Column G	Quantities w/Average Assigned by EPA-ORCR to Blanks in Column H	Year Begun
				toward Bethlehem Road in Rocky Mount					
54	Nash	Northside Business Park	Fill for construction of business park	2700 block of N. Wesleyan Boulevard, Rocky Mount	Cogentrix of Rocky Mount	41,000 tons	41,000	41,000	1996
55	Nash	E.B. Grain Co.	Fill for road bed material and building pad	Hwy 301 north of Rocky Mount	Cogentrix Rocky Mount, Hopewell, Portsmouth & Kenansville	25,000 tons for building pad; amount for road bed not specified	25,000	25,000	1991
56	Nash	Home Gallery Site	Fill on 3.8 acres of commercial property on U.S. 301 in Rocky Mount	DOES NOT SPECIFY	Cogentrix Hopewell, Portsmouth, Roxboro	5,000 cubic yards	5,000	5,000	1991
57	Nash	Randy Vann Property	Fill on 3-acre property	DOES NOT SPECIFY	"Cogentrix's fossil plants"	not specified		65,629	1990
58	Nash	Carolina Eagle Distributing	Structural fill for building pad as well as roadway and parking lot subsurface	Hwy 301 at College Park Road	Cogentrix Rocky Mount, Hopewell, Portsmouth & Kenansville	15,000 tons	15,000	15,000	1992
59	Nash	Swift Creek	Fill on a 25-acre site including wetland	Hwy 301 N. Battleboro near Rocky Mount	Cogentrix Kenansville	not specified		65,629	1994
60	Nash	Brandywine Industrial	16.5 acre fill on NC Hwy 4 near Rocky	on NC Hwy 4 near the US	Burlington Plant in Raeford, NC	not specified		65,629	2001

Exhibit S-2-2
Inventory of CCR Structural Fill Sites in North Carolina (1989-2009)

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Row	County	Project	Description	Location	Coal Ash Source	Amount of Ash Used	Quantity Assigned by EPA-ORCR based on Column G	Quantities w/Average Assigned by EPA-ORCR to Blanks in Column H	Year Begun
		Park	Mount Fire Department	Hwy 301/NC Hwy 4 intersection at Battleboro (between US Hwy 301 and SR 1560)					
61	Northampton	Arthur's Creek	Fill for development of office buildings, parking lot and access road at Henry B. Long industrial site	South side of NC Hwy 46, approx. 1 mile east of its intersection with I-95, west of Garysburg, NC	Roanoke Valley Energy, Weldon, NC	553,969 cubic yards	553,969	553,969	2004
62	Orange	Heatherly Farm	Utilizing ash from UNC-Chapel Hill power plant on a one-time basis to determine suitability of material as a substitute for commercial lime	Crawford Dairy Road at edge of Orange & Chatham counties	UNC-Chapel Hill cogeneration facility	600 tons	600	600	1992
63	Orange	Rougemont Hog Feeding Access Road	Construction of gravel hauling road at hog feeding site	Rougemont	UNC-Chapel Hill boiler plant	not specified		65,629	1993
64	Person	Roxboro Plant Gypsum	Expansion of facilities at power plant	Progress Roxboro plant, Cunningham	Progress Energy Roxboro Plant	131,319 cubic yards	131,319	131,319	1992

Exhibit S-2-2
Inventory of CCR Structural Fill Sites in North Carolina (1989-2009)

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Row	County	Project	Description	Location	Coal Ash Source	Amount of Ash Used	Quantity Assigned by EPA-ORCR based on Column G	Quantities w/Average Assigned by EPA-ORCR to Blanks in Column H	Year Begun
		Storage Pad		Township, Person County					
65	Robeson	Alamac Road	Filling a 12.8-acre parcel of land zoned for light industry	Along Alamac Road (SR 2289) south of Lumberton	Cogentrix plants in Lumberton, Elizabethtown & Kenansville	66,000 tons	66,000	66,000	1992
66	Robeson	Antone Project	A building pad and parking lot for a commercial office building		Cogentrix plant in Lumberton, Elizabethtown & Kenansville	5,000 cubic yards	5,000	5,000	1994
67	Rowan	Fieldcrest Cannon	Expansion of existing coal ash handling facility	2 miles northeast of Kannapolis between Pump Station Road and Glenn Avenue	Fieldcrest Cannon in Spencer, NC	14,000 to 16,000 cubic yards of ash is placed annually	16,000	16,000	1996
68	Stokes	Duke Energy Belews Station	Filing in abandoned sand filter system	Duke Power's Belews Creek Steam Station	Duke Belews Creek	475 cubic yards	475	475	1997
69	Stokes	SR 1908	20-acre fill on State Road 1908	Duke Power's Belews Creek Steam Station	Duke Belews Creek	not specified		65,629	2002
70	Stokes	Duke Belews Creek Steam Station	Industrial development site adjacent to power plant	Duke Power's Belews Creek Steam Station	Duke Belews Creek	918,300 cubic yards	918,300	918,300	2004
71	Washington	Crystal Ford	Site preparation for	Hwy 64 and	Plymouth	9,700 cubic	9,700	9,700	1993

Exhibit S-2-2
Inventory of CCR Structural Fill Sites in North Carolina (1989-2009)

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Row	County	Project	Description	Location	Coal Ash Source	Amount of Ash Used	Quantity Assigned by EPA-ORCR based on Column G	Quantities w/Average Assigned by EPA-ORCR to Blanks in Column H	Year Begun
		& Mercury	auto dealership	West Avenue, Plymouth	Weyerhaeuser Mill Complex	yards			
Column Totals =							4,761,685	5,365,279	
Column Average =							65,629		
Sub-total for the “large scale” sites highlighted in yellow + sand pit site highlighted in red =							2,500,019	47%	
Notes: - Source: All columns above except for column H and column I are from “North Carolina Documented Cases of Structural Fills Using Coal Ash as of January 2010. 2. 3,” Facing South/Institute for Southern Studies, May 2010, Vol.4 at http://www.southernstudies.org/images/.../NC_Structural_Fill_Sites.xls - EPA-ORCR constructed column I by assigning average CCR tons/cubic yards based on column H, to the sites without CCR quantity data in column H. For purpose of producing column totals for both column H and column I, EPA-ORCR did not standardize the CCR quantities in column I to either tonnage or to cubic yards, because there does not appear to be a uniform numerical relationship between tons and cubic yards for these CCR structural fill sites. This non-uniformity is evidenced by site row numbers 5 and 9 which provide the following tons-to-cubic-yards numerical ratios: - Site row 5: (22,000 tons) / (28,000 cubic yards) = 0.786 tons per cubic yard - Site row 9: (102,000 tons) / (85,000 cubic yards) = 1.200 tons per cubic yard - Average ratio based on these two sites = (0.786 + 1.200) / 2 = 0.993 tons per cubic yard (which rounds-up to 1.0) Based on the ratios calculated for these two sites, summing both tons and cubic yards together in column I does not appear to be a critical misuse of the CCR quantity data from column G because the average ratio of tons-per-cubic-yard is 1.0.									

Identify of 25 States Which Have CCR Structural Fill Regulations (as of 2010)

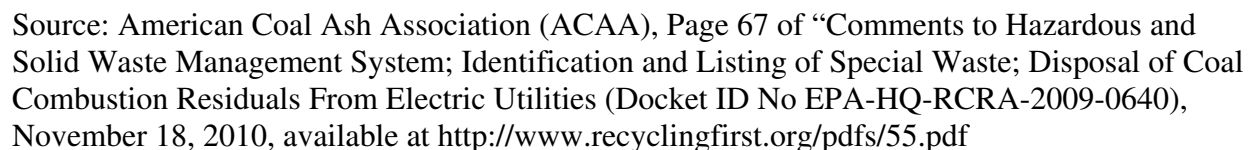


Exhibit S-2-4

Excerpts from State Government Regulations of CCR Structural Fill Interpretation of Regulations as Intentionally or Unintentionally Restricting/Prohibiting “Large Scale” Fill

State	Restriction?	Excerpt from State Regulation Used as Basis by EPA-ORCR for Assigning “Yes” or “No” for Restriction
1. AK	No	Not relevant - no CCR structural fill applications reported by ACAA in this state as of 2009"
2. AL	No	Not relevant - no CCR structural fill applications reported by ACAA in this state as of 2009"
3. AR	No	Not relevant - no CCR structural fill applications reported by ACAA in this state as of 2009"
4. AZ	No	Not relevant - no CCR structural fill applications reported by ACAA in this state as of 2009"
5. CA	No	Not relevant - no CCR structural fill applications reported by ACAA in this state as of 2009"
6. CO	No	No fill regulations
7. CT	No	Not relevant - no CCR structural fill applications reported by ACAA in this state as of 2009"
8. DE	No	No fill regulations
9. FL	No	Not relevant - no CCR structural fill applications reported by ACAA in this state as of 2009"
10. GA	No	No fill regulations
11. HI	No	Not relevant - no CCR structural fill applications reported by ACAA in this state as of 2009"
12. IA	Yes	Iowa regulations adopt by reference the federal regulation which exempts CCPs from classification as hazardous waste. Exempt from hazardous waste regulation are fly ash, bottom ash, slag and flue gas emission control waste generated primarily from the combustion of coal. IOWA ADMIN. CODE 567-141.2 (455B); 40 CFR 261.4. Under Iowa regulations, coal combustion residue includes bottom ash, fly ash, slag and flue gas desulfurization sludge produced through the combustion of coal, by itself or in combination with natural gas and other fuels. Coal combustion residues may be reused under permit by rule regulation as follows: - As a raw material in cement or concrete, filler in asphalt or plastic, and any other similar use where the coal combustion residue is bound up in cementitious material so that leaching and dusting do not occur. Use as a raw material does not include pretreating coal combustion residue for the purpose of disposal; As a fill base for roads, parking lots, and any other similar use, not to exceed an average of one ton for each twenty-five (25) square feet of area covered or an average thickness of twelve (12) inches;
13. ID	No	Not relevant - no CCR structural fill applications reported by ACAA in this state as of 2009"
14. IL	Yes	"CCW can be classified as CCB under certain conditions (satisfactory analytical testing results) and reused based on this classification. CCB may be reused as follows: - For the extraction and recovery of materials and compounds within the ash; - As a raw material in the manufacture of cement, concrete, concrete products and concrete mortars; - For asphalt or cement based roofing shingles; - In plastic products, paints and metal alloys; - In conformance with the specifications and under the approval of the Illinois Department of Transportation ("IDOT"); - As anti-skid material, athletic tracks or foot paths (bottom ash); - As a lime substitute in the lime modification of soils so long as the CCBs meet the IDOT specifications for by-product limes, and the functional equivalent for agricultural lime as a soil conditioner; - In non-IDOT pavement base, pipe bedding, or foundation backfill (bottom ash); As structural fill when used in an engineered application or combined with cement, sand or water to produce a controlled strength fill material and covered with 12 inches of soil unless infiltration is prevented by the material itself or other cover material; and For mine subsidence, mine fire control, mine sealing and mine reclamation."
15. IN	Yes	Under Indiana law (IN. Code 13-19-3-3(1)), coal combustion fly ash, bottom ash, or coal combustion fly ash or bottom ash in a mixture with flue gas desulfurization byproducts generated by the combustion of coal is not included in the definition of hazardous waste and is exempt from the hazardous waste regulations. Additionally, fly ash, bottom ash, or such ash when mixed with flue gas desulfurization byproducts or boiler slag, may not be regulated by the Solid Waste Management Board when used in the following manner: For the extraction and recovery of materials and compounds within the ash;

Exhibit S-2-4

Excerpts from State Government Regulations of CCR Structural Fill Interpretation of Regulations as Intentionally or Unintentionally Restricting/Prohibiting "Large Scale" Fill

State	Restriction?	Excerpt from State Regulation Used as Basis by EPA-ORCR for Assigning "Yes" or "No" for Restriction
		- As an anti-skid material (bottom ash); - As a raw material for the manufacturing of another product - For mine subsidence, mine fire control, and mine sealing (Note: restrictions may apply under the laws and regulations applicable to mining. See Indiana Department of Natural Resources regulations); As structural fill when combined with cement, sand or water to produce a controlled strength fill material; - As a base in road construction.
16. KS	No	No fill regulations
17. KY	No	Under Kentucky law, CCPs (as defined above) may be reused under permit by rule regulation as follows: - As an ingredient in manufacturing a product; - As an ingredient in cement, concrete, paint and plastics; - As anti-skid material; - As highway base course; Structural fill; - As blasting grit; - As roofing granules; and - For disposal in an active mining operation if the mine owner/operator has a mining permit which authorizes disposal of special waste. (See also KY. REV. STAT. ANN. §350.270.)
18. LA	No	Not relevant - no CCR structural fill applications reported by ACAA in this state as of 2009"
19. MA	No	Not relevant - no CCR structural fill applications reported by ACAA in this state as of 2009"
20. MD	No	Not relevant - no CCR structural fill applications reported by ACAA in this state as of 2009"
21. ME	No	Not relevant - no CCR structural fill applications reported by ACAA in this state as of 2009"
22. MI	No	Not relevant - no CCR structural fill applications reported by ACAA in this state as of 2009"
23. MN	No	No fill regulations
24. MO	Yes	Use of type C fly ash and associated bottom ash and boiler slag as road base or structural fill. (Note: For road base applications, the total mixture of soil and ash beneath the road may not exceed two feet. For structural fill applications, the area may not exceed five acres and the maximum depth of ash may not exceed two feet); - Use of type C fly ash as solid amendment or for soil stabilization. Note: For soil amendment applications, the total mixture of soil and ash may not exceed six inches. For soil stabilization applications, the area may not exceed five acres and the maximum ash depth may not exceed two feet. Note: For road base, structural fill, soil amendment, and soil stabilization applications, a renewed permit exemption must be obtained if the coal source changes or if coal processing changes affect the ash produced. The renewal request must be submitted at least 30 days prior to such a change. The DEQ may also authorize greater volumes of ash in these applications if the beneficial use is subject to a permit or exemption issued by the Missouri Clean Water Commission; and - Daily cover in a landfill (bottom ash or boiler slag).
25. MS	No	No fill regulations
26. MT	No	Not relevant - no CCR structural fill applications reported by ACAA in this state as of 2009"
27. NC	Yes	Under North Carolina regulations, CCPs which may be reused are defined to include fly ash, bottom ash, boiler slag and flue gas desulfurization residue produced by coal fired electrical or steam generation units. These CCPs may generally be beneficially reused as an ingredient in an industrial process to make a product, as an effective substitute for a commercial product or natural resource, and in structural fill. North Carolina regulations specify the following permissible CCP reuses:

Exhibit S-2-4

Excerpts from State Government Regulations of CCR Structural Fill Interpretation of Regulations as Intentionally or Unintentionally Restricting/Prohibiting "Large Scale" Fill

State	Restriction?	Excerpt from State Regulation Used as Basis by EPA-ORCR for Assigning "Yes" or "No" for Restriction
		In structural fill applications which comply with substantive requirements set forth in the regulations. Substantive regulatory requirements for structural fill applications include: Written notice to the state at least 30 days prior to commencement of structural fill projects containing: (1) a description of the nature, purpose, and location of the project, the location of the project on USGS maps, and a DOT map or topographic map showing the project; (2) the estimated start and completion dates for the project; (3) an estimate of the volume of CCPs to be used in the project; (4) TCLP analysis from a sample of each type of CCPs intended for use in the project; (5) a statement by the owner agreeing to comply with the County Recorder of Deed recording requirements in §.1707; and (6) specified information regarding the CCP generator; In projects using more than 10,000 cubic yards of CCPs, written notice to the state at least 30 days prior to commencement of CCP use containing construction plans for the structural fill facility, including a stability analysis when necessary, prepared, signed and sealed by a registered professional engineer; Compliance with location restrictions. CCPs used in structural fills may not be located within 50 feet of a jurisdictional wetland (absent additional regulatory approvals), a perennial stream or other water body, within 25 feet of any property boundary or bedrock outcrop, within two feet of the seasonal high groundwater table, within 100 feet of any drinking water source, or within a 100 year floodplain (absent additional regulatory approvals); Compliance with the following design, construction and operational requirements set forth in §.1705: the structural fill facility must be designed, constructed, operated, closed and maintained to minimize potential releases of CCPs and nuisance conditions; CCPs must be collected and transported to prevent public nuisances and hazards, must be moisture conditioned as needed, and transported in covered trucks to prevent dusting; CCPs must be placed uniformly and compacted in lifts not to exceed one foot in thickness and compacted to standards specified by a registered professional engineer for a specific end use purpose; equipment capable of placing and compacting CCPs and handling earth work must be present when CCPs are received at the area; the structural fill facility must be maintained and operated as a non-discharge system to prevent discharge to surface water and operated to ensure no violations of groundwater standards occur; surface waters resulting from precipitation must be diverted away from active CCP placement areas during filling and construction activity; site development must comply with the North Carolina Sedimentation Pollution Control Act of 1973; dust control measures must be undertaken to minimize airborne emissions and to prevent dust from creating a nuisance or safety hazard, and the project must not violate applicable air quality regulations; all structural fills must be covered with a minimum of 12" compacted earth and an additional surface of six inches of soil capable of supporting native plant growth; and CCPs utilized on an exterior slope of a structural fill shall not be placed with a slope greater than 3.0 horizontal to 1.0 vertical; Compliance with the following closure requirements set forth in §.1706: no later than 30 working days or 60 calendar days, whichever is less after CCP placement has ceased, the final cover must be applied over the area; the final surface of the structural fill must be graded and provided with drainage systems that minimize erosion of cover materials and promote drainage of area precipitation, minimize infiltration and prevent ponding of surface water on the structural fill; other erosion control measures such as temporary mulching, seeding or silt barriers must be installed to ensure no visible CCP product migration to adjacent property; the constructor or operator must submit a certification to the Agency signed and sealed by a registered professional engineer or the secretary of the Department of Transportation certifying that all requirements have been met. The report must be submitted within 30 days of application of final cover; and Compliance with the recording requirements set forth in §.1707 which include: Filing with the Register of Deeds, a statement signed and acknowledged by the landowners identifying the parcel of land, within 90 days of completion of any CCP structural fill project utilizing more than 1,000 cubic yards of CCPs. Transfers of such property must contain a statement that CCPs have been used as fill material on the property in the body of the deed.

Exhibit S-2-4

Excerpts from State Government Regulations of CCR Structural Fill Interpretation of Regulations as Intentionally or Unintentionally Restricting/Prohibiting "Large Scale" Fill

State	Restriction?	Excerpt from State Regulation Used as Basis by EPA-ORCR for Assigning "Yes" or "No" for Restriction
		In other applications authorized in §.1708 which include use of CCPs: • As soil nutrient additive or other agricultural purpose under the authority of the North Carolina Department of Agriculture; • Bottom ash or boiler slag as traction control material or road surface material if the use is approved by the North Carolina Department of Transportation; • As material in the manufacturing of another product, such as concrete products, lightweight aggregate, roofing materials, plastics, paint, flowable fill and roller compacted concrete or as a substitute for a product or material resource, including but not limited to, blasting grit, roofing granules, filter cloth, precoat for sludge dewatering and pipe bedding; • As a structural fill for the base or subbase under a structure, paved road, parking lot, sidewalk, walkway or similar structure; • For the extraction or recovery of materials and compounds contained within the CCPs. (Note: residuals from the processing operations remain solid waste and are subject to regulation); and • As a stabilized structural fill product when processed with a cementitious binder and spread and compacted for the construction of a project with a planned end use. Annual reporting is required. By October 1 of each year, generators of CCPs must submit an annual report summarizing the volume of CCPs produced, disposed, reused in structural fill and reused in other applications.
28. ND	Yes	Under North Dakota law and regulations, fly ash, bottom ash, slag and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels are exempt from regulation as hazardous waste. N.D. Century Code §23.20.3-10; N.D. ADMIN. CODE §33-24-02-04. Currently, reuse of CCPs is not specifically authorized under North Dakota law or regulations. The North Dakota Department of Health ("DOH") reports it has approved use of fly ash in concrete (up to 10-15%) and has approved demonstration projects for controlled low-strength material in dry underground mines. The DOH also reports it has been evaluating use of coal ash for structural fill and soil stabilization and use of bottom ash for road sand and road building. Proposed Reuse projects are evaluated on case by case basis by DOH
29. NE	Yes	On October 10, 1995, the Nebraska Department of Environmental Quality ("NDEQ") issued a policy on CCP reuse titled, "Guidance for Alternative Use of Coal Combustion By-Products and Other Similar Materials." The guidance was updated and revised July, 1997. Under the updated guidance, CCPs may be reused: • In the construction or manufacture of products (i.e. concrete, aggregate); • For hazardous waste stabilization; • For ice control (ice jams) in rivers. Note: A NPDES permit is required for this application; • As stabilizing agents and soil modification (i.e. base/subbase/subgrade under concrete, asphalt, armor coat, sand-gravel/limestone surfaces and roads, parking lots, or building sites); • As aggregate for roads, including armor coat and chip seal aggregate; • As structural fill including backfill of utility trenches and behind foundation walls, buildup of grade or as an embankment for roadways/overpasses; • As controlled density/slurry fill for closure of pipelines, tanks and sewers; • As a soil amendment (fly ash) under specific conditions. The fly ash must have a minimum calcium carbonate equivalence of 20%. The fly ash application rate must be based upon its neutralizing capacity and the amount of fly ash needed to raise the soil pH to an optimum level (pH 6.5 to 7.0). The application rate may not exceed ten tons per acre in any single annual application; and • Feedlot applications are conditionally approved so long as plans are submitted to NDEQ in advance for review and approval. The plans must describe the type and quantity of material to be used, application methods and procedures and the steps to be taken to ensure surface and groundwater will not be impacted.
30. NH	No	Not relevant - no CCR structural fill applications reported by ACAA in this state as of 2009"
31. NJ	No	No fill regulations

Exhibit S-2-4

Excerpts from State Government Regulations of CCR Structural Fill Interpretation of Regulations as Intentionally or Unintentionally Restricting/Prohibiting “Large Scale” Fill

State	Restriction?	Excerpt from State Regulation Used as Basis by EPA-ORCR for Assigning “Yes” or “No” for Restriction
32. NM	No	No fill regulations
33. NV	No	Not relevant - no CCR structural fill applications reported by ACAA in this state as of 2009"
34. NY	No	Not relevant - no CCR structural fill applications reported by ACAA in this state as of 2009"
35. OH	Yes	As structural fill, defined as an engineered use of waste material as a building or equipment supportive base or foundation and does not include valley fills or filling of open pits from coal or industrial mineral mining;
36. OK	No	Not relevant - no CCR structural fill applications reported by ACAA in this state as of 2009"
37. OR	No	Not relevant - no CCR structural fill applications reported by ACAA in this state as of 2009"
38. PA	Yes	• As a structural fill upon approval from the Department if the person proposing the use complies with specified requirements. (Any other use as a structural fill requires a disposal permit.); • As a soil substitute or soil additive if the person proposing the use complies with specified requirements; • For reclamation at an active surface coal mine site, a coal refuse reprocessing site, or a coal refuse disposal site if the use complies with all specified requirements under 25 Pa. Code §287.663, the Clean Streams Law and regulations promulgated thereunder, the Surface Mining Conservation and Reclamation act (52 P.S. §§1396.1-1396.19a), the Coal Refuse Disposal Control Act (52 P.S. §§30.51-30.66), and the applicable provisions of Chapters 86-90; • For reclamation at an abandoned coal or an abandoned noncoal (industrial mineral) mine site if the reclamation work is approved by the Department or is performed under a contract with the Department and the use complies with 25 Pa. Code §287.664, and the applicable environmental statutes and regulations promulgated thereunder;
39. RI	No	Not relevant - no CCR structural fill applications reported by ACAA in this state as of 2009"
40. SC	No	No fill regulations
41. SD	No	Not relevant - no CCR structural fill applications reported by ACAA in this state as of 2009"
42. TN	Yes	Under Tennessee law, fly ash, bottom ash and flue gas emission control waste generated from the combustion of coal or other fossil fuels must be tested for a hazardous waste determination. If determined to be hazardous, certain hazardous waste generator requirements apply. TENN.COMP. R. & REGS. 1200-1-11-.02. Upon testing confirmation that the material is not hazardous, fly ash, bottom ash and boiler slag may be reused under permit by rule regulation as follows: In engineered structures for a highway overpass, levee, runway or foundation backfill; and In other proposed beneficial uses approved on a case by case basis. (Note: The Tennessee Department of Environment and Conservation ("TDEC") issued a March 4, 1996 Guidance document setting forth the procedures and requirements to obtain approval of a proposed beneficial use.)
43. TX	Yes	• Fly ash/Bottom ash: In concrete, concrete products, cement/fly ash blends, pre-cast concrete products, lightweight and concrete aggregate, roller compacted concrete, soil cement, flowable fill, roofing material, insulation material, artificial reefs, and as mineral filler (plastics, paints, rubber matting, carpet backing, bricks and asphalt); • Fly ash/Bottom ash/FGD Material: As raw feed for concrete manufacture and in masonry; • Fly ash: In oil well cementing and waste stabilization and solidification; • Fly ash/Bottom ash/FGD Material: As roadbase when covered by a wear surface; • Bottom ash: As an unsurfaced road construction material, road surface traction material, and blasting grit; and • FGD Material: In wallboard and sheetrock.
44. UT	No	Not relevant - no CCR structural fill applications reported by ACAA in this state as of 2009"
45. VA	Yes	• As a material in the manufacturing of another product (e.g., concrete, concrete products, lightweight aggregate, roofing materials, plastics, paints, flowable fill) or as a substitute for a product or material resource (e.g., blasting grit, roofing granules, filter cloth precoat for sludge dewatering, pipe bedding); • For mine reclamation or mine refuse disposal on a mine site permitted by the Virginia Department of Mines, Minerals and Energy when used in accordance with the standards

Exhibit S-2-4

Excerpts from State Government Regulations of CCR Structural Fill Interpretation of Regulations as Intentionally or Unintentionally Restricting/Prohibiting "Large Scale" Fill

State	Restriction?	Excerpt from State Regulation Used as Basis by EPA-ORCR for Assigning "Yes" or "No" for Restriction
		developed by the Department of Waste Management; - For soil nutrient additive, stabilization agent, structural improvement or other agricultural purposes under the authority of the Virginia Department of Agriculture and Consumer Services; - As a traction control material or road surface material if the use is consistent with Virginia Department of Transportation specifications (bottom ash or boiler slag); - As a base, subbase or fill material under a paved road, the footprint of a structure, a paved parking lot, sidewalk, walkway or similar structure; When processed with a cementitious binder to produce a stabilized structural fill product which is spread and compacted with proper equipment for the construction of a project with a specified end use; and - For the extraction or recovery of materials and compounds contained within the CCPs. In 1995, Virginia promulgated a regulation specifying the terms and conditions under which CCPs may be reused through land application such as structural fills, mine reclamation or mine refuse disposal (in conjunction with Virginia Surface Mining regulations). The regulation allows for the use of CCPs in structural fills and mine reclamation projects. The regulation also provides for the siting of such projects, the design and construction of runoff and cover systems, the closure of projects, and establishes minimum operational requirements. Provide a description of the intended use, reuse, or reclamation of the CCPs including a description of the site, the estimated beginning and ending dates of the operation, an estimate of the volume of CCPs to be used, and the physical and chemical characteristics of the CCPs including TCLP analyses for specified characteristics; Certification by a professional engineer that locational restrictions have been satisfied and that the project has been designed in accordance with specified standards; and An operational and closure plan.
46. VT	No	Not relevant - no CCR structural fill applications reported by ACAA in this state as of 2009"
47. WA	No	Not relevant - no CCR structural fill applications reported by ACAA in this state as of 2009"
48. WI	No	Under Wisconsin regulations, fly ash, bottom ash, slag and flue gas emission control waste are exempt from regulation as hazardous waste. In Wisconsin, coal ash, bottom ash, and slag are classified as "industrial products." Industrial products are placed in one of five categories depending on the results of analytical testing, with Category 1 being essentially inert and Category 5 having relatively high levels of the tested constituents. - Category 1 products have the following authorized reuse options: 1) raw material for manufacturing a product; 2) waste stabilization/solidification; 3) supplemental fuel source/energy recovery; 4) landfill daily cover/internal structures; 5) confined geotechnical fill; 6) encapsulated transportation facility embankment; 7) capped transportation facility embankment; 8) unconfined geotechnical fill; 9) unbonded surface course; 10) bonded surface course; 11) decorative stone; and 12) cold weather road abrasive; and 13) general beneficial use in accordance with state regulations. - Category 2 materials are authorized for uses 1-12, - Category 3 materials are authorized for uses 1-8, Category 4 materials are authorized for uses 1-6, and - Category 5 materials are authorized for uses 1-4. Product generators must certify their industrial materials annually.
49. WV	No	Under West Virginia regulations, CCPs may be reused in the following manner: - As a material in manufacturing another product (e.g. concrete, flowable fill, lightweight aggregate, concrete block, roofing materials, plastics, paint) or as a substitute for a product or natural resource (e.g. blasting grit, filter cloth precoat for sludge dewatering); - For the extraction or recovery of materials and compounds contained within the CCPs; - As a stabilization/solidification agent for other wastes if used singly or in combination with other additives or agents to stabilize or solidify another waste product. Advance written notice must be submitted to the state and the use must result in altered physical or chemical characteristics of the other waste and a reduction of the potential for the resulting established mixture to leach constituents

Exhibit S-2-4

Excerpts from State Government Regulations of CCR Structural Fill Interpretation of Regulations as Intentionally or Unintentionally Restricting/Prohibiting “Large Scale” Fill

State	Restriction?	Excerpt from State Regulation Used as Basis by EPA-ORCR for Assigning “Yes” or “No” for Restriction
		into the environment; Under the authority of the West Virginia Department of Energy; • As pipe bedding or as a composite liner drainage layer; • As an anti-skid material (bottom ash, boiler slag) if such use is consistent with Department of Highways specifications. The use of fly ash as an anti-skid material is not deemed to be a beneficial use; • As a daily or intermediate cover for certain solid waste facilities if the permit allows for such use; and As a construction base for roads or parking lots that have asphalt or concrete wearing surfaces, if approved by the West Virginia Department of Highways and the project owner. West Virginia regulations note that beneficial reuse of CCPs for structural fills and as soil amendment will be addressed in future rule makings.
50. WY	Yes	Wyoming regulations adopt by reference the federal regulation which exempts CCPs from classification as hazardous waste. Exempt from hazardous waste regulation are fly ash, bottom ash, slag and flue gas emission control waste generated primarily from the combustion of coal. WY ADMIN. CODE HWM CH. 2 §1; 40 CFR 261.4. Wyoming law regulates CCPs as an industrial solid waste. WY ADMIN. CODE SWM CH. 1, §1(e)(i). Currently, reuse of CCPs is not specifically authorized under Wyoming law or regulations. According to the Wyoming Department of Environmental Quality, the agency is in the process of developing regulatory guidelines for beneficial reuse of solid waste, including CCPs.
Source: US Dept of Energy, National Energy Technology Laboratory (NETL), “IEP - Coal Utilization By-Products: Current Regulations Governing Coal Combustion By-Products - State Links” website at: http://www.netl.doe.gov/technologies/coalpower/ewr/coal_utilization_byproducts/states/select_state.html		

Exhibit S-2-5 Estimate of State Government CCR Structural Fill Tons and Percentage Which May be “Large Scale”								
A	B	C	D	E (C x D)	F	G	H	I (H x 47%)
Item	State	2004 CCR beneficial use (short tons)	% of US total CCR beneficial use in each state (based on C)	EPA-ORCR estimate of 2009 CCR beneficial use in each state	BU estimates from column E only for 25 states with CCR structural fill applications (tons)	Percentage for each of the 25 states in Column F	EPA-ORCR estimate of CCR structural fill in 25 states which have fill applications	EPA-ORCR estimate of CCR structural fill that may be “large scale” sites (short tons)
1	AK	Not reported	Not reported	Not reported				
2	AL	663,000	1.48%	826,163				
3	AR	324,000	0.73%	403,736				
4	AZ	1,161,000	2.60%	1,446,720				
5	CA	0	0.00%	0				
6	CO	252,000	0.56%	314,017	314,017	0.76%	67,205	31,586
7	CT	0	0.00%	0				
8	DC	0	0.00%	0				
9	DE	24,000	0.05%	29,906	29,906	0.07%	6,400	3,008
10	FL	3,171,000	7.10%	3,951,377				
11	GA	1,022,000	2.29%	1,273,512	1,273,512	3.08%	272,554	128,100
12	HI	0	0.00%	0				
13	IA	750,000	1.68%	934,573	934,573	2.26%	200,015	
14	ID	0	0.00%	0				
15	IL	1,968,000	4.41%	2,452,321	2,452,321	5.93%	524,839	
16	IN	3,023,000	6.77%	3,766,954	3,766,954	9.10%	806,194	
17	KS	575,000	1.29%	716,506	716,506	1.73%	153,345	72,072
18	KY	2,521,000	5.65%	3,141,413	3,141,413	7.59%	672,317	315,989
19	LA	716,000	1.60%	892,206				
20	MA	130,000	0.29%	161,993				
21	MD	646,000	1.45%	804,979				
22	ME	0	0.00%	0				
23	MI	614,000	1.38%	765,104				
24	MN	387,000	0.87%	482,240	482,240	1.17%	103,208	48,508
25	MO	1,070,000	2.40%	1,333,325	1,333,325	3.22%	285,355	
26	MS	681,000	1.53%	848,593	848,593	2.05%	181,614	85,358
27	MT	51,000	0.11%	63,551				
28	NC	1,641,000	3.68%	2,044,847	2,044,847	4.94%	437,633	
29	ND	731,000	1.64%	910,898	910,898	2.20%	194,948	
30	NE	299,000	0.67%	372,583	372,583	0.90%	79,739	
31	NH	57,000	0.13%	71,028				
32	NJ	112,000	0.25%	139,563	139,563	0.34%	29,869	14,038
33	NM	864,000	1.93%	1,076,629	1,076,629	2.60%	230,417	108,296
34	NV	314,000	0.70%	391,275				
35	NY	368,000	0.82%	458,564				
36	OH	2,290,000	5.13%	2,853,564	2,853,564	6.90%	610,712	
37	OK	625,000	1.40%	778,811				
38	OR	81,000	0.18%	100,934				
39	PA	2,941,000	6.59%	3,664,774	3,664,774	8.86%	784,325	
40	RI	0	0.00%	0				
41	SC	1,169,000	2.62%	1,456,688	1,456,688	3.52%	311,757	146,526
42	SD	28,000	0.06%	34,891				

Exhibit S-2-5

Estimate of State Government CCR Structural Fill Tons and Percentage Which May be “Large Scale”

A	B	C	D	E (C x D)	F	G	H	I (H x 47%)
Item	State	2004 CCR beneficial use (short tons)	% of US total CCR beneficial use in each state (based on C)	EPA-ORCR estimate of 2009 CCR beneficial use in each state	BU estimates from column E only for 25 states with CCR structural fill applications (tons)	Percentage for each of the 25 states in Column F	EPA-ORCR estimate of CCR structural fill in 25 states which have fill applications	EPA-ORCR estimate of CCR structural fill that may be “large scale” sites (short tons)
43	TN	2,163,000	4.84%	2,695,310	2,695,310	6.51%	576,843	
44	TX	4,395,000	9.84%	5,476,600	5,476,600	13.23%	1,172,088	
45	UT	812,000	1.82%	1,011,832				
46	VA	203,000	0.45%	252,958	252,958	0.61%	54,137	
47	VT	0	0.00%	0				
48	WA	1,683,000	3.77%	2,097,183				
49	WI	1,219,000	2.73%	1,518,993	1,518,993	3.67%	325,091	152,793
50	WV	2,401,000	5.38%	2,991,881	2,991,881	7.23%	640,315	300,948
51	WY	508,000	1.14%	633,018	633,018	1.53%	135,477	
Column totals =		44,653,000	100%	55,642,011	41,381,666	100%	8,856,396	1,407,222
% CCR structural fill tons estimated to be “large scale” sites (based on 2 indicators >450,000 tons & sand/gravel pits)=								16%

Sources:

- Column C: US Dept of Energy & US Environmental Protection Agency, “Coal Combustion Waste Management at Landfills and Surface Impoundments 1994-2004,” DOE/PI-0004, Aug 2006, page 5 (Table 1) at: http://www.ead.anl.gov/pub/doc/coal_waste_report.pdf. In comparison ACAA reports 49,089,818 tons CCR beneficial use for 2004 at [http://acaaffiniscape.com/associations/8003/files/2004_CCP_Survey\(9-9-05\).pdf](http://acaaffiniscape.com/associations/8003/files/2004_CCP_Survey(9-9-05).pdf). This table uses the DOE/EPA data because the ACAA does not provide its CCR beneficial use data on a state-by-state basis.
- Column E: Column total from American Coal Ash Association (ACAA) CCR beneficial use data for 2009 at http://www.acaa-usa.org/associations/8003/files/2009_Production_and_Use_Survey_Revised_100511.pdf. Relative to the ACAA 2009 US total CCR beneficial use tons, EPA-ORCR estimated state-by-state 2009 CCR beneficial use tons, by multiplying the ACAA US total by the state-by-state percentages in column D.
- Column H: EPA-ORCR estimated state-by-state CCR structural fill tons for each of the 25 states, by multiplying the ACAA US total structural fill tons (8,856,396 tons), by the state-by-state percentages shown in column G.
- Column I: 47% multiplier is based on the results for the NC structural fill data displayed in Exhibit 2. Orange shaded cells indicate states which may have current restrictions on “large scale” CCR structural fill applications (based on evaluation of current state regulations displayed in Exhibit 4).

APPENDIX T

Offsite Commercial Industrial Landfill Capacity Analysis

Note: EPA has updated this sensitivity analysis in the RIA; see **Chapter 9** of this RIA for a description of the relevant modifications and the resultant recalculations. The sensitivity analysis in this appendix presents non-modified calculations and totals in accordance with **Chapters 4** and **5** of this RIA. Because the modifications made in **Chapter 9** do not directly affect the uncertainties and parameters examined in this appendix, the *relative impacts* displayed in the sensitivity analysis presented in this appendix do not differ substantially between the figures presented in this appendix and the corresponding potential impacts of these sensitivity analyses on the modified, recalculated results presented in **Chapter 9**.

Offsite Commercial Industrial Landfill Capacity Analysis

The results of the regulatory cost estimation in this RIA indicate that 7% of the universe of CCR impoundments may cease operating under the 100-year baseline of this RIA (in response to various state regulations), and an additional 7% of the universe of CCR impoundments may cease operating under the CCR final rule.¹ In addition, the results of the regulatory cost estimation in this RIA estimate that of the 310 existing, on-site landfills, 13% will close and shift disposal to off-site landfills in the baseline scenario, and an additional 18% will do so in the post-rule scenario.²

Exhibit T-1 below presents, on both a probability-weighted unit count and total CCR tonnage basis:

- The post-rule scenario probability-weighted future counts of CCR disposal impoundments modeled to cease operating and switch to offsite commercial industrial landfills;
- The post-rule scenario probability-weighted future counts of CCR disposal impoundments that convert to storage impoundments, where the associated CCR is dredged annually and deposited in offsite commercial industrial landfills; and
- The post-rule scenario probability-weighted future counts of on-site CCR landfills modeled to cease operating and switch disposal to offsite commercial industrial landfills.

This RIA assumes that all landfill and disposal impoundment CCR tonnage which may switch to offsite landfills, switches to offsite commercial landfills (i.e. fee-based landfills owned/operated by waste management companies or by local governments), because this RIA does not have data on ownership status of offsite landfills (i.e., whether some offsite landfills which receive CCR may be owned by utility companies). As displayed in the bottom row of **Exhibit T-1**, the average annual future CCR tonnage which may switch to offsite landfills under the CCR final rule is estimated at 10.9 million tons per year.

¹ A probability-weighted 48 out of 142 disposal impoundments are modeled to close in the baseline. 48 / 735 (which includes the 142 disposal impoundments and the 593 storage impoundments) yields an estimate of approximately 7% of impoundments closing in the baseline. In the post-rule scenario, the probability-weighted quantity grows to 98 disposal impoundments, and 98 / 735 yields approximately 13% of all impoundment units closing.

² A probability-weighted 41 of 310 on-site landfills are modeled as closing and shifting to off-site disposal in the baseline, as well as 98 of 310 in the post-rule scenario.

Exhibit T-1								
Projection of Post-Rule Scenario Tonnages Currently Disposed Onsite Shifting to Offsite Disposal								
		Post-Rule Scenario						
Period of Analysis	Year	Disp. SIs closing and shifting disposal offsite	Associated CCR tonnage	Disp. SIs converting to storage SIs, dredging, and disposing offsite	Associated CCR tonnage	Landfills closing and shifting disposal offsite	Associated CCR Tonnage	Total Tonnage Shifted to Offsite Disposal*
1	2015	0	0	0	26,317	0	0	19,907
2	2016	0	0	0	26,254	0	0	19,859
3	2017	0	0	1	43,967	0	0	33,258
4	2018	0	0	1	43,856	0	0	33,174
5	2019	0	0	1	43,763	0	0	33,103
6	2020	3	964,931	1	43,659	0	0	762,928
7	2021	4	968,137	1	43,568	0	0	765,284
8	2022	4	969,278	1	43,484	0	0	766,083
9	2023	4	970,457	1	43,400	0	0	766,911
10	2024	5	1,334,430	1	43,323	0	0	1,042,173
11	2025	5	1,335,376	1	43,258	0	0	1,042,840
12	2026	6	1,423,055	1	43,182	0	0	1,109,105
13	2027	6	1,423,949	1	43,119	0	0	1,109,734
14	2028	7	1,561,509	1	43,054	0	0	1,213,738
15	2029	7	1,562,633	1	42,987	0	0	1,214,538
16	2030	9	2,531,217	1	42,930	1	1,000	1,948,160
17	2031	9	2,531,847	1	42,868	1	1,000	1,948,591
18	2032	9	2,532,381	1	42,811	1	1,000	1,948,952
19	2033	9	2,533,202	1	42,742	1	1,000	1,949,521
20	2034	10	2,641,876	1	42,679	3	1,000	2,031,678
21	2035	10	2,691,080	1	42,626	4	1,000	2,068,856
22	2036	10	2,691,694	1	42,582	4	1,000	2,069,287
23	2037	10	2,692,293	1	42,532	4	1,000	2,069,703
24	2038	10	2,692,911	1	42,486	4	1,000	2,070,136
25	2039	10	2,693,505	1	42,441	4	1,000	2,070,550
26	2040	12	2,776,657	1	42,389	5	170,100	2,302,510
27	2041	12	2,777,014	1	42,345	5	170,100	2,302,747
28	2042	12	2,777,512	1	42,297	6	170,100	2,303,088
29	2043	12	2,777,941	1	42,250	6	170,100	2,303,376
30	2044	12	2,826,862	1	42,207	6	170,100	2,340,349
31	2045	14	3,100,034	1	42,171	7	170,100	2,546,957
32	2046	14	3,100,357	1	42,127	8	287,200	2,664,269
33	2047	14	3,100,681	1	42,093	8	287,200	2,664,487
34	2048	14	3,100,924	1	42,039	9	287,200	2,664,631
35	2049	14	3,101,167	1	42,001	9	287,200	2,664,785
36	2050	15	3,109,740	1	41,955	10	322,700	2,706,736
37	2051	16	3,847,668	1	41,917	10	322,700	3,264,897
38	2052	16	3,847,668	1	41,885	10	322,700	3,264,873
39	2053	16	3,920,618	1	41,852	10	322,700	3,320,030
40	2054	16	3,920,618	1	41,818	12	719,400	3,716,704
41	2055	16	3,920,618	1	41,789	12	719,400	3,716,682
42	2056	16	3,920,618	1	41,745	13	785,400	3,782,649

Exhibit T-1								
Projection of Post-Rule Scenario Tonnages Currently Disposed Onsite Shifting to Offsite Disposal								
		Post-Rule Scenario						
Period of Analysis	Year	Disp. SIs closing and shifting disposal offsite	Associated CCR tonnage	Disp. SIs converting to storage SIs, dredging, and disposing offsite	Associated CCR tonnage	Landfills closing and shifting disposal offsite	Associated CCR Tonnage	Total Tonnage Shifted to Offsite Disposal*
43	2057	16	3,920,618	1	41,711	15	785,400	3,782,623
44	2058	16	3,920,618	1	41,669	17	2,993,700	5,990,891
45	2059	16	3,920,618	1	41,636	23	3,920,150	6,917,316
46	2060	16	3,920,618	1	41,604	26	4,340,350	7,337,492
47	2061	16	3,920,618	1	41,581	31	4,783,817	7,780,941
48	2062	16	3,920,618	1	41,547	35	5,902,017	8,899,115
49	2063	16	3,920,618	1	41,522	40	7,358,217	10,355,296
50	2064	16	3,920,618	1	41,489	42	7,708,867	10,705,922
51	2065	16	3,920,618	1	41,455	46	8,299,167	11,296,196
52	2066	16	3,920,618	1	41,421	50	9,061,367	12,058,370
53	2067	16	3,920,618	1	41,388	52	10,075,667	13,072,645
54	2068	17	4,236,310	1	41,356	53	10,410,767	13,646,519
55	2069	17	4,236,310	1	41,327	54	10,410,767	13,646,498
56	2070	17	4,236,310	1	41,298	56	10,747,767	13,983,476
57	2071	17	4,236,310	1	41,270	61	11,557,633	14,793,321
58	2072	17	4,236,310	1	41,247	65	12,729,433	15,965,104
59	2073	17	4,236,310	1	41,212	66	12,767,833	16,003,478
60	2074	17	4,236,310	1	41,187	68	12,982,521	16,218,147
61	2075	17	4,236,310	1	41,149	71	13,153,421	16,389,018
62	2076	17	4,236,310	1	41,138	72	14,093,621	17,329,209
63	2077	17	4,236,310	1	41,122	73	14,186,021	17,421,597
64	2078	17	4,236,310	1	41,122	74	14,930,021	18,165,597
65	2079	17	4,236,310	1	41,122	74	14,930,021	18,165,597
66	2080	17	4,236,310	1	41,122	77	15,303,321	18,538,897
67	2081	17	4,236,310	1	41,122	78	15,347,221	18,582,797
68	2082	17	4,236,310	1	41,122	78	15,347,221	18,582,797
69	2083	17	4,236,310	1	41,122	82	15,481,304	18,716,881
70	2084	17	4,236,310	1	41,122	82	15,481,304	18,716,881
71	2085	17	4,236,310	1	41,122	84	15,639,354	18,874,931
72	2086	17	4,236,310	1	41,122	86	15,648,688	18,884,264
73	2087	17	4,236,310	1	41,122	87	15,687,088	18,922,664
74	2088	17	4,236,310	1	41,122	89	16,126,688	19,362,264
75	2089	17	4,236,310	1	41,122	91	16,495,888	19,731,464
76	2090	17	4,236,310	1	41,122	96	17,390,538	20,626,114
77	2091	17	4,236,310	1	41,122	98	18,096,088	21,331,664
78	2092	17	4,236,310	1	41,122	98	18,096,088	21,331,664
79	2093	17	4,236,310	1	41,122	98	18,096,088	21,331,664
80	2094	17	4,236,310	1	41,122	98	18,096,088	21,331,664
81	2095	17	4,236,310	1	41,122	98	18,096,088	21,331,664
82	2096	17	4,236,310	1	41,122	98	18,096,088	21,331,664
83	2097	17	4,236,310	1	41,122	98	18,096,088	21,331,664
84	2098	17	4,236,310	1	41,122	98	18,096,088	21,331,664

Exhibit T-1 Projection of Post-Rule Scenario Tonnages Currently Disposed Onsite Shifting to Offsite Disposal								
Period of Analysis	Year	Post-Rule Scenario						
		Disp. SIs closing and shifting disposal offsite	Associated CCR tonnage	Disp. SIs converting to storage SIs, dredging, and disposing offsite	Associated CCR tonnage	Landfills closing and shifting disposal offsite	Associated CCR Tonnage	Total Tonnage Shifted to Offsite Disposal*
85	2099	17	4,236,310	1	41,122	98	18,096,088	21,331,664
86	2100	17	4,236,310	1	41,122	98	18,096,088	21,331,664
87	2101	17	4,236,310	1	41,122	98	18,096,088	21,331,664
88	2102	17	4,236,310	1	41,122	98	18,096,088	21,331,664
89	2103	17	4,236,310	1	41,122	98	18,096,088	21,331,664
90	2104	17	4,236,310	1	41,122	98	18,096,088	21,331,664
91	2105	17	4,236,310	1	41,122	98	18,096,088	21,331,664
92	2106	17	4,236,310	1	41,122	98	18,096,088	21,331,664
93	2107	17	4,236,310	1	41,122	98	18,096,088	21,331,664
94	2108	17	4,236,310	1	41,122	98	18,096,088	21,331,664
95	2109	17	4,236,310	1	41,122	98	18,096,088	21,331,664
96	2110	17	4,236,310	1	41,122	98	18,096,088	21,331,664
97	2111	17	4,236,310	1	41,122	98	18,096,088	21,331,664
98	2112	17	4,236,310	1	41,122	98	18,096,088	21,331,664
99	2113	17	4,236,310	1	41,122	98	18,096,088	21,331,664
100	2114	17	4,236,310	1	41,122	98	18,096,088	21,331,664
Average annual CCR tons modeled as switching to CCR landfills =								10,900,621
* Because dry-handled CCR tons and wet-handled CCR tons are not comparable on an apples-to-apples basis due to density differentials, this analysis converts all wet-handled tons to dry-handled tons using the 1.322 scaling factor (i.e., dividing by 1.322) before adding them to dry-handled tons from existing, on-site landfills to arrive at a total tonnage shifted to offsite disposal in the post-rule scenario.								

Exhibit T-2 below presents this RIA's state-by-state summary of existing (as of data year 2010) offsite commercial industrial waste landfill capacity. The bottom row of **Exhibit T-2** indicates 2.486 billion tons of commercial industrial waste capacity. In comparison to remaining capacity of offsite commercial industrial landfills beyond year 2010, the average annual CCR tonnage this RIA estimates may switch to offsite landfills would potentially exhaust the remaining capacity not until 228 years, calculated as follows (2.486 billion tons offsite commercial industrial waste landfill capacity) / (10.9 million tons per year) = 228 years. This illustrative calculation assumes that all other waste streams deposited in these same offsite landfills remain constant over this future time period. The considerable available off-site capacity in **Exhibit T-2** indicates that even if certain assumptions are relaxed, such as the adjustment of wet-handled CCR tonnage to a dry-handled basis or the use of an average annual CCR tonnage disposed offsite rather than the maximum amount, enough offsite commercial industrial landfill capacity exists to receive the projected increases in offsite disposal for over 100 years.³

³ Specifically, by treating the tonnage in **Exhibit T-1** on a wet-handled basis, the maximum tonnage shifting to offsite in a given year is approximately 22.4 million tons, or less than 1% of the 2,485 million tons of available industrial commercial offsite landfill capacity as per **Exhibit T-2**.

Exhibit T-2						
Remaining Capacity Beyond 2010 at Offsite Commercial Industrial Waste Landfills						
Row	State	2010 count of commercial industrial waste landfills in operation	State-wide average operating days per year	Industrial waste landfill total size (acres)	Annual quantity of industrial waste received (tons per year)	Remaining industrial landfill capacity beyond 2010
1	AL	19	298	3,100	2,916,763	55,761,253
2	AK	0	0	0	0	0
3	AR	4	299	256	643,466	0
4	AZ	7	305	2,951	2,281,511	71,175,717
5	CA	74	311	24,027	19,291,844	308,908,478
6	CO	12	312	1,885	2,400,260	43,615,198
7	CT	1	312	173	42,632	0
8	DC	0	0	0	0	0
9	DE	1	312	572	224,927	1,799,416
10	FL	40	311	27,346	9,097,176	152,759,261
11	GA	17	306	5,959	5,483,247	67,349,786
12	HI	0	0	0	0	0
13	IA	3	312	360	216,413	6,203,256
14	ID	7	297	1,653	572,624	9,034,272
15	IL	15	295	4,348	5,907,548	93,479,986
16	IN	32	301	4,551	7,410,309	40,054,940
17	IA	0	0	0	0	0
18	KS	25	308	2,698	1,882,696	36,681,778
19	KY	7	290	3,050	953,285	34,864,153
20	LA	5	291	900	583,276	8,450,096
21	MA	0	0	0	0	0
22	MD	12	312	2,596	1,227,392	6,960,789
23	ME	3	277	924	192,011	3,487,597
24	MI	25	291	3,233	7,508,220	41,978,074
25	MN	3	295	568	266,841	5,117,398
26	MO	5	302	320	905,927	3,311,431
27	MS	3	312	97	809,518	11,389,488
28	MT	0	0	0	0	0
29	NC	10	307	2,436	1,335,918	12,565,585
30	ND	0	0	0	0	0
31	NH	1	260	51	87,269	1,919,918
32	NJ	12	303	2,516	2,448,900	19,755,571
33	NM	11	303	2,163	1,194,838	61,448,537
34	NV	20	294	4,136	3,147,731	242,174,359
35	NY	18	289	5,777	5,750,247	139,054,846
36	OH	36	296	8,259	10,588,276	158,298,787
37	OK	4	312	353	1,153,164	4,525,981
38	OR	20	304	4,926	3,842,512	166,765,763
39	PA	46	293	12,678	10,348,154	62,113,505
40	SC	2	312	261	841,336	11,778,705
41	SD	0	0	0	0	0
42	TN	2	286	275	351,948	5,838,587
43	TX	69	300	11,842	14,300,741	208,660,683
44	UT	8	299	6,121	645,362	51,680,262
45	VA	45	309	13,583	9,047,511	242,824,742
46	VT	1	312	0	370,001	1,110,002
47	WA	8	319	3,876	3,397,280	59,799,609
48	WI	21	285	3,835	5,874,581	31,256,508
49	WV	1	312	600	119,658	2,034,190
50	WY	0	0	0	0	0
Column totals =		655		175,255	145,663,313	2,485,989,000
Data source: Columns C through G: EPA-ORCR calculated state-by-state industrial waste landfill sub-totals based on analysis of facility-by-facility landfill data in the Waste Business Journal "Directory of Waste Processing & Disposal Sites 2010" available at http://www.wastebusinessjournal.com/diratlas.htm						

APPENDIX U

Demographic Data for EJ Analysis

Note: EPA has updated the universe to reflect 61 actual and projected plant retirements occurring after 2012 according to the National Electric Energy Data System (NEEDS) v.5.13 dataset; see **Section 9.2.1** in **Chapter 9** for a description of the relevant updates. Exhibits in this appendix have not been updated to reflect the revisions described in **Section 9.2.1**.

Exhibit U-1: National Demographic Benchmarks

Exhibit U-2: Demographic Data Used to Characterize CCR Surface Impoundments

Exhibit U-3: Demographic Data Used to Characterize CCR Landfills

Exhibit U-1	
National Demographic Benchmarks	
Percent Minority	24.8%
Percent Poverty	11.3%
Percent Under-18	24.0%

Exhibit U-2

Demographic Data Used to Characterize CCR Surface Impoundments

Plant ID	State	Population within One Mile	Population under 18	Population in Poverty	Native American Population	Minority Population (includes Native American)	State Percent Minority	State Percent Poverty	State Percent Under-18
3	AL	115	26	8	0	18	28.9%	14.6%	23.7%
7	AL	4699	1384	1386	10	969	28.9%	14.6%	23.7%
8	AL	168	34	21	0	10	28.9%	14.6%	23.7%
10	AL	36	7	6	0	10	28.9%	14.6%	23.7%
26	AL	250	58	20	0	21	28.9%	14.6%	23.7%
47	AL	63	22	5	0	8	28.9%	14.6%	23.7%
50	AL	182	44	26	6	23	28.9%	14.6%	23.7%
51	LA	22	5	5	0	9	36.1%	17.3%	24.7%
56	AL	427	82	91	6	140	28.9%	14.6%	23.7%
60	NE	37	12	1	1	2	10.4%	8.9%	25.1%
87	NM	0	0	0	0	0	33.2%	17.3%	25.2%
113	AZ	20	0	0	0	0	24.5%	12.5%	25.5%
127	TX	1	0	1	0	0	29.1%	14.6%	27.3%
130	SC	88	29	23	0	42	32.7%	12.8%	23.4%
160	AZ	25	2	1	0	9	24.5%	12.5%	25.5%
165	OK	75	32	40	18	31	23.9%	13.8%	24.8%
298	TX	16	2	0	0	2	29.1%	14.6%	27.3%
465	CO	9395	2661	1257	136	3460	17.1%	8.9%	24.4%
469	CO	300	58	20	2	98	17.1%	8.9%	24.4%
470	CO	10	3	0	0	6	17.1%	8.9%	24.4%
477	CO	1163	254	43	2	145	17.1%	8.9%	24.4%
492	CO	4898	1062	970	42	1193	17.1%	8.9%	24.4%
525	CO	35	4	0	0	0	17.1%	8.9%	24.4%
527	CO	102	21	18	1	9	17.1%	8.9%	24.4%
594	DE	164	44	21	1	41	25.3%	8.7%	22.9%
602	MD	747	194	42	0	120	36.0%	7.9%	23.4%
641	FL	800	51	8	3	25	22.1%	11.7%	21.3%
642	FL	73	18	19	0	15	22.1%	11.7%	21.3%
643	FL	20	4	8	0	6	22.1%	11.7%	21.3%
645	FL	472	28	10	0	30	22.1%	11.7%	21.3%
663	FL	107	25	5	0	16	22.1%	11.7%	21.3%
703	GA	993	360	47	1	107	35.0%	12.3%	25.7%
708	GA	108	20	14	0	12	35.0%	12.3%	25.7%
709	GA	747	149	55	0	246	35.0%	12.3%	25.7%
710	GA	4482	805	758	17	1870	35.0%	12.3%	25.7%
727	GA	121	41	19	0	49	35.0%	12.3%	25.7%
728	GA	165	53	17	1	44	35.0%	12.3%	25.7%
733	GA	1168	289	53	1	266	35.0%	12.3%	25.7%
753	GA	257	65	33	0	104	35.0%	12.3%	25.7%
856	IL	319	18	2	0	1	26.4%	10.0%	24.4%
861	IL	71	7	5	0	0	26.4%	10.0%	24.4%
874	IL	2295	681	341	8	889	26.4%	10.0%	24.4%
876	IL	14	1	1	0	0	26.4%	10.0%	24.4%
879	IL	976	114	22	0	8	26.4%	10.0%	24.4%
883	IL	1495	399	153	2	795	26.4%	10.0%	24.4%
887	IL	586	162	69	10	57	26.4%	10.0%	24.4%

Exhibit U-2

Demographic Data Used to Characterize CCR Surface Impoundments

Plant ID	State	Population within One Mile	Population under 18	Population in Poverty	Native American Population	Minority Population (includes Native American)	State Percent Minority	State Percent Poverty	State Percent Under-18
889	IL	398	118	31	0	11	26.4%	10.0%	24.4%
891	IL	1257	315	143	0	52	26.4%	10.0%	24.4%
892	IL	0	0	0	0	0	26.4%	10.0%	24.4%
898	IL	530	142	76	1	56	26.4%	10.0%	24.4%
963	IL	2487	660	245	3	383	26.4%	10.0%	24.4%
976	IL	372	55	18	0	17	26.4%	10.0%	24.4%
983	IN	625	36	8	0	3	12.5%	8.8%	24.8%
988	IN	1743	276	53	0	37	12.5%	8.8%	24.8%
990	IN	530	116	38	0	15	12.5%	8.8%	24.8%
991	IN	411	108	15	0	5	12.5%	8.8%	24.8%
994	IN	227	62	19	0	6	12.5%	8.8%	24.8%
995	IN	32	0	0	0	0	12.5%	8.8%	24.8%
997	IN	4400	1414	788	3	831	12.5%	8.8%	24.8%
1001	IN	6	1	1	0	4	12.5%	8.8%	24.8%
1004	IN	323	75	32	0	10	12.5%	8.8%	24.8%
1008	IN	4351	763	715	12	1690	12.5%	8.8%	24.8%
1010	IN	714	41	23	6	14	12.5%	8.8%	24.8%
1012	IN	38	12	0	0	1	12.5%	8.8%	24.8%
1040	IN	3641	868	550	4	248	12.5%	8.8%	24.8%
1043	IN	216	27	18	0	5	12.5%	8.8%	24.8%
1046	IA	8631	2317	1559	22	610	6.1%	8.3%	23.9%
1047	IA	82	26	14	0	3	6.1%	8.3%	23.9%
1048	IA	558	101	85	4	15	6.1%	8.3%	23.9%
1073	IA	928	133	69	3	40	6.1%	8.3%	23.9%
1077	IA	41	7	0	0	0	6.1%	8.3%	23.9%
1081	IA	1120	334	135	2	198	6.1%	8.3%	23.9%
1082	IA	16	7	0	0	0	6.1%	8.3%	23.9%
1091	IA	18	1	0	0	0	6.1%	8.3%	23.9%
1104	IA	103	23	4	0	5	6.1%	8.3%	23.9%
1122	IA	5082	921	1005	9	513	6.1%	8.3%	23.9%
1239	KS	875	273	124	43	106	13.8%	8.9%	25.5%
1241	KS	12	0	1	0	0	13.8%	8.9%	25.5%
1250	KS	166	28	10	0	9	13.8%	8.9%	25.5%
1252	KS	538	138	25	6	85	13.8%	8.9%	25.5%
1353	KY	156	19	16	0	0	9.9%	13.9%	23.6%
1355	KY	174	36	10	0	7	9.9%	13.9%	23.6%
1356	KY	123	10	0	0	0	9.9%	13.9%	23.6%
1357	KY	145	9	10	0	3	9.9%	13.9%	23.6%
1361	KY	87	14	17	1	3	9.9%	13.9%	23.6%
1363	KY	1990	538	320	4	193	9.9%	13.9%	23.6%
1364	KY	2139	41	19	0	12	9.9%	13.9%	23.6%
1374	KY	1499	296	85	4	50	9.9%	13.9%	23.6%
1378	KY	0	0	0	0	0	9.9%	13.9%	23.6%
1379	KY	34	6	3	0	0	9.9%	13.9%	23.6%
1381	KY	66	1	0	0	0	9.9%	13.9%	23.6%
1382	KY	20	6	0	0	1	9.9%	13.9%	23.6%

Exhibit U-2

Demographic Data Used to Characterize CCR Surface Impoundments

Plant ID	State	Population within One Mile	Population under 18	Population in Poverty	Native American Population	Minority Population (includes Native American)	State Percent Minority	State Percent Poverty	State Percent Under-18
1385	KY	210	38	9	0	8	9.9%	13.9%	23.6%
1570	MD	1864	415	199	4	109	36.0%	7.9%	23.4%
1619	MA	3983	500	181	2	91	15.4%	8.4%	21.7%
1702	MI	214	6	1	2	2	19.8%	9.7%	23.7%
1720	MI	176	34	6	2	7	19.8%	9.7%	23.7%
1723	MI	533	89	19	0	14	19.8%	9.7%	23.7%
1731	MI	1437	381	156	9	53	19.8%	9.7%	23.7%
1733	MI	765	207	75	4	43	19.8%	9.7%	23.7%
1740	MI	3221	1091	986	13	981	19.8%	9.7%	23.7%
1743	MI	1016	197	81	8	62	19.8%	9.7%	23.7%
1745	MI	2994	691	193	9	286	19.8%	9.7%	23.7%
1825	MI	3049	744	222	9	390	19.8%	9.7%	23.7%
1830	MI	10332	3717	1066	12	2001	19.8%	9.7%	23.7%
1832	MI	206	53	14	0	21	19.8%	9.7%	23.7%
1891	MN	248	19	4	3	5	10.5%	6.9%	24.2%
1893	MN	120	37	21	22	24	10.5%	6.9%	24.2%
1904	MN	3959	985	144	10	411	10.5%	6.9%	24.2%
2049	MS	1783	458	212	4	546	38.6%	17.6%	25.5%
2076	MO	13	6	7	0	1	15.1%	10.6%	23.8%
2079	MO	1	0	0	0	0	15.1%	10.6%	23.8%
2080	MO	1	0	0	0	0	15.1%	10.6%	23.8%
2094	MO	398	120	39	4	38	15.1%	10.6%	23.8%
2098	MO	2420	647	427	8	206	15.1%	10.6%	23.8%
2103	MO	0	0	0	0	0	15.1%	10.6%	23.8%
2104	MO	478	108	14	1	15	15.1%	10.6%	23.8%
2107	MO	30	5	0	0	0	15.1%	10.6%	23.8%
2123	MO	7400	1766	2331	19	1576	15.1%	10.6%	23.8%
2132	MO	1134	322	92	3	112	15.1%	10.6%	23.8%
2161	MO	1572	348	61	12	72	15.1%	10.6%	23.8%
2167	MO	2	0	0	0	0	15.1%	10.6%	23.8%
2168	MO	10	2	3	0	0	15.1%	10.6%	23.8%
2169	MO	510	162	67	0	15	15.1%	10.6%	23.8%
2171	MO	237	78	5	0	18	15.1%	10.6%	23.8%
2187	MT	1242	324	412	116	168	9.4%	13.3%	22.6%
2291	NE	8238	2225	1213	151	3253	10.4%	8.9%	25.1%
2324	NV	93	9	15	0	14	24.8%	9.4%	24.6%
2364	NH	1701	257	70	4	58	3.9%	5.6%	21.8%
2442	NM	9	2	3	3	4	33.2%	17.3%	25.2%
2527	NY	478	150	90	3	22	32.0%	13.2%	22.3%
2549	NY	1170	336	136	17	79	32.0%	13.2%	22.3%
2554	NY	4194	954	815	12	398	32.0%	13.2%	22.3%
2706	NC	1966	502	310	8	380	27.8%	11.7%	23.9%
2708	NC	84	14	0	0	28	27.8%	11.7%	23.9%
2709	NC	320	63	21	2	82	27.8%	11.7%	23.9%
2712	NC	291	41	40	0	81	27.8%	11.7%	23.9%
2713	NC	7	1	3	0	2	27.8%	11.7%	23.9%

Exhibit U-2

Demographic Data Used to Characterize CCR Surface Impoundments

Plant ID	State	Population within One Mile	Population under 18	Population in Poverty	Native American Population	Minority Population (includes Native American)	State Percent Minority	State Percent Poverty	State Percent Under-18
2718	NC	1020	232	48	8	175	27.8%	11.7%	23.9%
2720	NC	495	113	56	0	90	27.8%	11.7%	23.9%
2721	NC	272	48	30	0	26	27.8%	11.7%	23.9%
2727	NC	863	188	39	1	127	27.8%	11.7%	23.9%
2732	NC	101	16	2	0	4	27.8%	11.7%	23.9%
2817	ND	2	0	0	0	0	7.7%	10.4%	22.3%
2823	ND	2	0	0	0	0	7.7%	10.4%	22.3%
2824	ND	30	12	13	3	3	7.7%	10.4%	22.3%
2828	OH	1336	92	45	1	35	15.1%	9.8%	23.7%
2830	OH	554	77	25	0	9	15.1%	9.8%	23.7%
2832	OH	0	0	0	0	0	15.1%	9.8%	23.7%
2835	OH	155	30	38	0	6	15.1%	9.8%	23.7%
2836	OH	2812	699	147	9	142	15.1%	9.8%	23.7%
2837	OH	3385	736	151	8	120	15.1%	9.8%	23.7%
2838	OH	13121	5161	5321	8	11716	15.1%	9.8%	23.7%
2840	OH	244	51	28	0	7	15.1%	9.8%	23.7%
2843	OH	29	2	4	0	0	15.1%	9.8%	23.7%
2848	OH	1074	306	88	3	294	15.1%	9.8%	23.7%
2850	OH	258	7	1	0	0	15.1%	9.8%	23.7%
2866	OH	435	94	62	1	25	15.1%	9.8%	23.7%
2872	OH	146	37	10	0	7	15.1%	9.8%	23.7%
2876	OH	460	111	80	4	20	15.1%	9.8%	23.7%
2878	OH	675	201	50	1	43	15.1%	9.8%	23.7%
2952	OK	429	17	6	2	8	23.9%	13.8%	24.8%
2963	OK	666	171	80	79	171	23.9%	13.8%	24.8%
3098	PA	1055	224	79	0	55	14.6%	9.5%	22.0%
3113	PA	146	25	7	0	3	14.6%	9.5%	22.0%
3118	PA	987	120	96	0	1	14.6%	9.5%	22.0%
3122	PA	171	14	1	0	0	14.6%	9.5%	22.0%
3131	PA	110	27	15	0	6	14.6%	9.5%	22.0%
3136	PA	220	17	8	0	4	14.6%	9.5%	22.0%
3138	PA	931	185	100	2	50	14.6%	9.5%	22.0%
3140	PA	524	155	34	0	23	14.6%	9.5%	22.0%
3149	PA	119	15	3	0	0	14.6%	9.5%	22.0%
3152	PA	2321	427	156	2	57	14.6%	9.5%	22.0%
3179	PA	764	208	120	1	39	14.6%	9.5%	22.0%
3251	SC	310	88	38	7	124	32.7%	12.8%	23.4%
3264	SC	421	75	54	2	45	32.7%	12.8%	23.4%
3280	SC	89	21	14	0	26	32.7%	12.8%	23.4%
3295	SC	902	298	97	3	296	32.7%	12.8%	23.4%
3297	SC	15	0	2	0	2	32.7%	12.8%	23.4%
3319	SC	529	145	71	1	217	32.7%	12.8%	23.4%
3325	SD	1874	451	232	161	243	11.3%	11.4%	24.9%
3393	TN	0	0	0	0	0	19.8%	12.6%	23.6%
3396	TN	836	171	69	1	28	19.8%	12.6%	23.6%
3399	TN	242	53	29	3	26	19.8%	12.6%	23.6%

Exhibit U-2

Demographic Data Used to Characterize CCR Surface Impoundments

Plant ID	State	Population within One Mile	Population under 18	Population in Poverty	Native American Population	Minority Population (includes Native American)	State Percent Minority	State Percent Poverty	State Percent Under-18
3403	TN	353	106	16	0	34	19.8%	12.6%	23.6%
3405	TN	380	94	82	2	10	19.8%	12.6%	23.6%
3406	TN	406	73	31	1	35	19.8%	12.6%	23.6%
3407	TN	817	174	121	0	27	19.8%	12.6%	23.6%
3470	TX	56	11	0	0	10	29.1%	14.6%	27.3%
3497	TX	3	0	0	0	0	29.1%	14.6%	27.3%
3644	UT	1	0	1	0	0	10.8%	8.8%	31.5%
3775	VA	85	14	17	0	1	27.7%	8.9%	23.2%
3776	VA	249	53	45	0	18	27.7%	8.9%	23.2%
3796	VA	198	44	38	0	62	27.7%	8.9%	23.2%
3797	VA	678	2	1	0	3	27.7%	8.9%	23.2%
3803	VA	1870	702	157	4	706	27.7%	8.9%	23.2%
3935	WV	2362	415	165	2	151	5.0%	15.5%	20.9%
3936	WV	1350	357	217	0	100	5.0%	15.5%	20.9%
3938	WV	746	86	57	0	22	5.0%	15.5%	20.9%
3942	WV	332	73	110	3	13	5.0%	15.5%	20.9%
3945	WV	1447	288	292	0	83	5.0%	15.5%	20.9%
3947	WV	400	92	91	0	28	5.0%	15.5%	20.9%
3948	WV	120	16	12	0	9	5.0%	15.5%	20.9%
3982	WI	3372	866	580	191	295	11.1%	8.1%	23.6%
4050	WI	7234	1658	307	11	509	11.1%	8.1%	23.6%
4054	WI	402	110	60	0	6	11.1%	8.1%	23.6%
4057	WI	777	85	16	4	42	11.1%	8.1%	23.6%
4072	WI	120	40	29	7	30	11.1%	8.1%	23.6%
4078	WI	790	108	11	1	15	11.1%	8.1%	23.6%
4158	WY	0	0	0	0	0	8.1%	7.2%	24.0%
4162	WY	0	0	0	0	0	8.1%	7.2%	24.0%
6002	AL	638	135	61	7	221	28.9%	14.6%	23.7%
6004	WV	1011	227	197	5	48	5.0%	15.5%	20.9%
6016	IL	0	0	0	0	0	26.4%	10.0%	24.4%
6017	IL	15	5	0	0	0	26.4%	10.0%	24.4%
6018	KY	42	17	16	0	0	9.9%	13.9%	23.6%
6019	OH	147	59	12	0	11	15.1%	9.8%	23.7%
6030	ND	0	0	0	0	0	7.7%	10.4%	22.3%
6031	OH	51	16	11	0	0	15.1%	9.8%	23.7%
6034	MI	361	71	30	6	22	19.8%	9.7%	23.7%
6041	KY	93	24	3	0	4	9.9%	13.9%	23.6%
6052	GA	23	3	5	0	4	35.0%	12.3%	25.7%
6055	LA	48	9	12	0	18	36.1%	17.3%	24.7%
6061	MS	49	11	8	0	5	38.6%	17.6%	25.5%
6064	KS	130	29	24	0	73	13.8%	8.9%	25.5%
6068	KS	12	1	0	0	0	13.8%	8.9%	25.5%
6071	KY	35	9	5	0	0	9.9%	13.9%	23.6%
6073	MS	366	103	44	5	83	38.6%	17.6%	25.5%
6076	MT	1341	425	90	237	322	9.4%	13.3%	22.6%
6082	NY	110	30	15	0	1	32.0%	13.2%	22.3%

Exhibit U-2

Demographic Data Used to Characterize CCR Surface Impoundments

Plant ID	State	Population within One Mile	Population under 18	Population in Poverty	Native American Population	Minority Population (includes Native American)	State Percent Minority	State Percent Poverty	State Percent Under-18
6085	IN	238	60	17	0	17	12.5%	8.8%	24.8%
6089	MT	126	25	16	14	15	9.4%	13.3%	22.6%
6090	MN	59	5	0	0	0	10.5%	6.9%	24.2%
6094	PA	1449	91	41	0	29	14.6%	9.5%	22.0%
6095	OK	34	13	2	0	5	23.9%	13.8%	24.8%
6096	NE	2	0	2	0	0	10.4%	8.9%	25.1%
6098	SD	6	0	0	0	0	11.3%	11.4%	24.9%
6101	WY	11	0	0	0	1	8.1%	7.2%	24.0%
6113	IN	74	2	0	0	0	12.5%	8.8%	24.8%
6124	GA	8	0	0	0	2	35.0%	12.3%	25.7%
6136	TX	51	0	2	0	2	29.1%	14.6%	27.3%
6137	IN	116	14	16	0	0	12.5%	8.8%	24.8%
6138	AR	212	41	22	5	20	20.1%	15.0%	24.4%
6139	TX	73	24	8	0	16	29.1%	14.6%	27.3%
6146	TX	22	0	0	0	0	29.1%	14.6%	27.3%
6147	TX	0	0	0	0	0	29.1%	14.6%	27.3%
6155	MO	3	1	0	0	0	15.1%	10.6%	23.8%
6166	IN	23	5	4	0	0	12.5%	8.8%	24.8%
6177	AZ	0	0	0	0	0	24.5%	12.5%	25.5%
6178	TX	39	10	0	0	15	29.1%	14.6%	27.3%
6179	TX	1	0	0	0	0	29.1%	14.6%	27.3%
6180	TX	4	0	1	0	2	29.1%	14.6%	27.3%
6181	TX	52	17	19	0	35	29.1%	14.6%	27.3%
6183	TX	0	0	0	0	0	29.1%	14.6%	27.3%
6190	LA	12	2	1	0	1	36.1%	17.3%	24.7%
6195	MO	159	34	14	5	7	15.1%	10.6%	23.8%
6204	WY	16	3	4	0	0	8.1%	7.2%	24.0%
6238	IL	145	37	11	0	1	26.4%	10.0%	24.4%
6248	CO	25	10	14	0	6	17.1%	8.9%	24.4%
6249	SC	529	12	0	0	21	32.7%	12.8%	23.4%
6250	NC	32	8	2	0	7	27.8%	11.7%	23.9%
6254	IA	41	9	0	0	0	6.1%	8.3%	23.9%
6257	GA	2	0	2	0	0	35.0%	12.3%	25.7%
6264	WV	238	67	41	0	15	5.0%	15.5%	20.9%
6288	AK	0	0	0	0	0	0.0%	0.0%	26.4%
6481	UT	0	0	0	0	0	10.8%	8.8%	31.5%
6639	KY	6	1	0	0	0	9.9%	13.9%	23.6%
6648	TX	4	0	0	0	0	29.1%	14.6%	27.3%
6664	IA	319	43	9	0	3	6.1%	8.3%	23.9%
6705	IN	63	22	0	0	1	12.5%	8.8%	24.8%
6761	CO	6	0	0	0	0	17.1%	8.9%	24.4%
6768	MO	5217	1661	1407	23	1168	15.1%	10.6%	23.8%
6772	OK	0	0	0	0	0	23.9%	13.8%	24.8%
7097	TX	76	17	19	0	35	29.1%	14.6%	27.3%
7213	VA	49	16	9	0	21	27.7%	8.9%	23.2%
7790	UT	0	0	0	0	0	10.8%	8.8%	31.5%

Exhibit U-2

Demographic Data Used to Characterize CCR Surface Impoundments

Plant ID	State	Population within One Mile	Population under 18	Population in Poverty	Native American Population	Minority Population (includes Native American)	State Percent Minority	State Percent Poverty	State Percent Under-18
7902	TX	11	0	0	0	0	29.1%	14.6%	27.3%
8023	WI	149	42	9	0	6	11.1%	8.1%	23.6%
8042	NC	228	72	14	0	23	27.8%	11.7%	23.9%
8066	WY	0	0	0	0	0	8.1%	7.2%	24.0%
8069	UT	3	0	0	0	0	10.8%	8.8%	31.5%
8102	OH	258	63	35	0	3	15.1%	9.8%	23.7%
8222	ND	6	1	0	0	0	7.7%	10.4%	22.3%
8226	PA	7587	1587	566	2	316	14.6%	9.5%	22.0%
10030	DE	4256	1140	529	44	1206	25.3%	8.7%	22.9%
10151	WV	781	185	99	0	43	5.0%	15.5%	20.9%
10771	VA	5195	1554	1257	21	2596	27.7%	8.9%	23.2%
55076	MS	56	13	22	0	21	38.6%	17.6%	25.5%

Exhibit U-3

Demographic Data Used to Characterize CCR Landfills

Plant ID	State	Population within One Mile	Population under 18	Population in Poverty	Native American Population	Minority Population (includes Native American)	State Percent Minority	State Percent Poverty	State Percent Under-18
8	AL	57	12	11	0	1	28.9%	14.6%	23.7%
47	AL	36	8	6	0	6	28.9%	14.6%	23.7%
51	LA	0	0	0	0	0	36.1%	17.3%	24.7%
56	AL	71	30	25	6	44	28.9%	14.6%	23.7%
59	NE	26	4	3	0	0	10.4%	8.9%	25.1%
87	NM	0	0	0	0	0	33.2%	17.3%	25.2%
108	KS	0	0	0	0	0	13.8%	8.9%	25.5%
113	AZ	6	3	0	0	5	24.5%	12.5%	25.5%
127	TX	1	0	1	0	0	29.1%	14.6%	27.3%
130	SC	93	24	25	0	51	32.7%	12.8%	23.4%
136	FL	6	0	0	0	2	22.1%	11.7%	21.3%
165	OK	162	51	46	35	59	23.9%	13.8%	24.8%
207	FL	121	0	0	0	2	22.1%	11.7%	21.3%
298	TX	24	3	0	0	2	29.1%	14.6%	27.3%
384	IL	1617	456	155	8	578	26.4%	10.0%	24.4%
470	CO	10	3	0	0	6	17.1%	8.9%	24.4%
477	CO	178	33	30	0	25	17.1%	8.9%	24.4%
492	CO	8147	1804	1447	89	1967	17.1%	8.9%	24.4%
525	CO	7	0	0	0	0	17.1%	8.9%	24.4%
527	CO	106	21	17	1	9	17.1%	8.9%	24.4%
564	FL	48	8	3	0	9	22.1%	11.7%	21.3%
594	DE	378	82	34	0	86	25.3%	8.7%	22.9%
628	FL	3	0	0	0	0	22.1%	11.7%	21.3%
641	FL	1251	306	65	9	227	22.1%	11.7%	21.3%
643	FL	20	3	6	0	6	22.1%	11.7%	21.3%
645	FL	2683	429	175	10	385	22.1%	11.7%	21.3%
663	FL	491	106	26	0	80	22.1%	11.7%	21.3%
667	FL	63	17	7	0	12	22.1%	11.7%	21.3%
676	FL	787	215	64	2	183	22.1%	11.7%	21.3%
703	GA	1372	456	76	6	148	35.0%	12.3%	25.7%
708	GA	33	3	1	0	6	35.0%	12.3%	25.7%
710	GA	4408	836	783	17	1943	35.0%	12.3%	25.7%
728	GA	214	72	18	1	39	35.0%	12.3%	25.7%
733	GA	792	184	66	3	183	35.0%	12.3%	25.7%
861	IL	63	13	12	0	1	26.4%	10.0%	24.4%
876	IL	14	1	0	0	0	26.4%	10.0%	24.4%
887	IL	481	144	62	10	49	26.4%	10.0%	24.4%
892	IL	335	102	20	4	18	26.4%	10.0%	24.4%
963	IL	2681	473	113	0	194	26.4%	10.0%	24.4%
976	IL	354	74	23	0	20	26.4%	10.0%	24.4%
983	IN	441	96	19	0	4	12.5%	8.8%	24.8%
988	IN	838	284	36	0	28	12.5%	8.8%	24.8%
994	IN	234	64	20	0	6	12.5%	8.8%	24.8%
1001	IN	12	5	1	0	9	12.5%	8.8%	24.8%
1004	IN	432	120	54	1	12	12.5%	8.8%	24.8%
1008	IN	6120	1646	1354	14	3258	12.5%	8.8%	24.8%

Exhibit U-3									
Demographic Data Used to Characterize CCR Landfills									
Plant ID	State	Population within One Mile	Population under 18	Population in Poverty	Native American Population	Minority Population (includes Native American)	State Percent Minority	State Percent Poverty	State Percent Under-18
1047	IA	86	18	11	0	1	6.1%	8.3%	23.9%
1082	IA	124	36	6	0	1	6.1%	8.3%	23.9%
1091	IA	18	2	3	0	4	6.1%	8.3%	23.9%
1131	IA	866	254	113	4	161	6.1%	8.3%	23.9%
1167	IA	34	8	3	0	1	6.1%	8.3%	23.9%
1217	IA	36	12	0	0	0	6.1%	8.3%	23.9%
1241	KS	12	5	2	0	0	13.8%	8.9%	25.5%
1250	KS	2758	720	195	44	239	13.8%	8.9%	25.5%
1252	KS	647	167	29	5	93	13.8%	8.9%	25.5%
1295	KS	4581	1211	1087	26	2223	13.8%	8.9%	25.5%
1363	KY	1271	329	181	3	115	9.9%	13.9%	23.6%
1364	KY	2749	181	75	0	59	9.9%	13.9%	23.6%
1379	KY	32	6	3	0	0	9.9%	13.9%	23.6%
1382	KY	13	4	0	0	0	9.9%	13.9%	23.6%
1384	KY	588	115	97	0	2	9.9%	13.9%	23.6%
1393	LA	747	220	108	0	195	36.1%	17.3%	24.7%
1570	MD	1925	445	225	3	131	36.0%	7.9%	23.4%
1571	MD	551	138	39	6	389	36.0%	7.9%	23.4%
1572	MD	113	32	4	0	20	36.0%	7.9%	23.4%
1573	MD	805	270	46	6	231	36.0%	7.9%	23.4%
1619	MA	5667	874	304	5	232	15.4%	8.4%	21.7%
1702	MI	77	22	3	2	2	19.8%	9.7%	23.7%
1710	MI	351	101	13	0	31	19.8%	9.7%	23.7%
1720	MI	61	16	3	2	2	19.8%	9.7%	23.7%
1745	MI	7684	1761	264	9	642	19.8%	9.7%	23.7%
1769	MI	111	23	4	4	4	19.8%	9.7%	23.7%
1830	MI	251	83	2	0	18	19.8%	9.7%	23.7%
1893	MN	21	0	1	0	0	10.5%	6.9%	24.2%
1915	MN	5842	1573	275	18	355	10.5%	6.9%	24.2%
1943	MN	2016	344	56	6	36	10.5%	6.9%	24.2%
2049	MS	1288	327	101	4	353	38.6%	17.6%	25.5%
2079	MO	4	0	0	0	3	15.1%	10.6%	23.8%
2080	MO	6	0	0	1	1	15.1%	10.6%	23.8%
2094	MO	75	24	9	0	7	15.1%	10.6%	23.8%
2161	MO	1423	396	49	14	68	15.1%	10.6%	23.8%
2167	MO	13	3	3	0	1	15.1%	10.6%	23.8%
2168	MO	12	2	3	0	0	15.1%	10.6%	23.8%
2240	NE	4921	1150	270	40	261	10.4%	8.9%	25.1%
2277	NE	235	3	1	0	0	10.4%	8.9%	25.1%
2291	NE	10687	2446	1336	160	3633	10.4%	8.9%	25.1%
2324	NV	138	46	9	0	35	24.8%	9.4%	24.6%
2364	NH	1268	297	74	4	50	3.9%	5.6%	21.8%
2403	NJ	1360	305	209	2	931	27.4%	7.8%	23.5%
2408	NJ	7014	1494	456	28	2346	27.4%	7.8%	23.5%
2442	NM	9	2	3	3	4	33.2%	17.3%	25.2%
2527	NY	494	171	104	3	22	32.0%	13.2%	22.3%

Exhibit U-3

Demographic Data Used to Characterize CCR Landfills

Plant ID	State	Population within One Mile	Population under 18	Population in Poverty	Native American Population	Minority Population (includes Native American)	State Percent Minority	State Percent Poverty	State Percent Under-18
2535	NY	124	34	10	1	7	32.0%	13.2%	22.3%
2549	NY	1075	256	42	17	53	32.0%	13.2%	22.3%
2554	NY	3135	839	543	10	307	32.0%	13.2%	22.3%
2712	NC	194	27	24	0	38	27.8%	11.7%	23.9%
2718	NC	744	187	45	7	132	27.8%	11.7%	23.9%
2727	NC	291	78	24	1	42	27.8%	11.7%	23.9%
2790	ND	269	49	17	4	7	7.7%	10.4%	22.3%
2817	ND	4	0	0	1	1	7.7%	10.4%	22.3%
2823	ND	4	0	0	0	0	7.7%	10.4%	22.3%
2824	ND	30	0	0	0	0	7.7%	10.4%	22.3%
2828	OH	488	114	65	0	27	15.1%	9.8%	23.7%
2830	OH	635	196	56	2	21	15.1%	9.8%	23.7%
2832	OH	644	2	0	0	0	15.1%	9.8%	23.7%
2836	OH	3618	895	195	20	210	15.1%	9.8%	23.7%
2837	OH	5685	1355	292	16	207	15.1%	9.8%	23.7%
2840	OH	554	133	46	0	17	15.1%	9.8%	23.7%
2850	OH	18	4	1	0	0	15.1%	9.8%	23.7%
2866	OH	97	22	7	0	12	15.1%	9.8%	23.7%
2876	OH	256	68	43	0	15	15.1%	9.8%	23.7%
2878	OH	783	225	47	3	49	15.1%	9.8%	23.7%
2963	OK	15	1	0	1	1	23.9%	13.8%	24.8%
3113	PA	7322	2031	752	4	430	14.6%	9.5%	22.0%
3115	PA	8462	56	18	2	23	14.6%	9.5%	22.0%
3118	PA	186	43	27	1	15	14.6%	9.5%	22.0%
3122	PA	251	59	24	1	8	14.6%	9.5%	22.0%
3131	PA	136	31	18	0	6	14.6%	9.5%	22.0%
3136	PA	241	52	34	0	0	14.6%	9.5%	22.0%
3138	PA	746	168	81	2	47	14.6%	9.5%	22.0%
3140	PA	512	156	34	0	14	14.6%	9.5%	22.0%
3149	PA	306	82	9	0	7	14.6%	9.5%	22.0%
3178	PA	430	104	57	1	7	14.6%	9.5%	22.0%
3179	PA	302	72	41	0	9	14.6%	9.5%	22.0%
3181	PA	246	59	17	0	2	14.6%	9.5%	22.0%
3287	SC	538	156	42	4	77	32.7%	12.8%	23.4%
3295	SC	634	218	62	2	206	32.7%	12.8%	23.4%
3297	SC	64	16	14	0	35	32.7%	12.8%	23.4%
3298	SC	1151	34	12	0	36	32.7%	12.8%	23.4%
3396	TN	1694	438	193	4	60	19.8%	12.6%	23.6%
3399	TN	180	54	29	3	26	19.8%	12.6%	23.6%
3405	TN	357	93	74	2	12	19.8%	12.6%	23.6%
3406	TN	730	13	3	0	6	19.8%	12.6%	23.6%
3470	TX	29	14	0	0	11	29.1%	14.6%	27.3%
3497	TX	3	0	0	0	0	29.1%	14.6%	27.3%
3644	UT	224	57	36	19	45	10.8%	8.8%	31.5%
3775	VA	35	5	7	0	1	27.7%	8.9%	23.2%
3776	VA	210	45	46	0	13	27.7%	8.9%	23.2%

Exhibit U-3

Demographic Data Used to Characterize CCR Landfills

Plant ID	State	Population within One Mile	Population under 18	Population in Poverty	Native American Population	Minority Population (includes Native American)	State Percent Minority	State Percent Poverty	State Percent Under-18
3803	VA	2540	962	256	8	976	27.7%	8.9%	23.2%
3809	VA	287	65	8	0	36	27.7%	8.9%	23.2%
3845	WA	24	7	9	0	0	18.2%	9.2%	23.5%
3935	WV	949	108	35	0	23	5.0%	15.5%	20.9%
3938	WV	914	256	162	1	33	5.0%	15.5%	20.9%
3942	WV	22	5	10	0	1	5.0%	15.5%	20.9%
3943	WV	138	25	28	0	9	5.0%	15.5%	20.9%
3944	WV	432	91	52	1	28	5.0%	15.5%	20.9%
3945	WV	818	80	36	0	17	5.0%	15.5%	20.9%
3946	WV	101	28	11	0	8	5.0%	15.5%	20.9%
3954	WV	0	0	0	0	0	5.0%	15.5%	20.9%
3982	WI	86	26	6	2	8	11.1%	8.1%	23.6%
4041	WI	1514	304	29	4	108	11.1%	8.1%	23.6%
4042	WI	6116	184	20	0	60	11.1%	8.1%	23.6%
4050	WI	7834	37	5	0	5	11.1%	8.1%	23.6%
4078	WI	771	8	1	0	0	11.1%	8.1%	23.6%
4140	WI	209	41	10	1	8	11.1%	8.1%	23.6%
4143	WI	314	81	29	1	7	11.1%	8.1%	23.6%
4158	WY	1	0	0	0	0	8.1%	7.2%	24.0%
4162	WY	0	0	0	0	0	8.1%	7.2%	24.0%
4271	WI	201	41	9	1	8	11.1%	8.1%	23.6%
4941	AZ	10	5	8	6	8	24.5%	12.5%	25.5%
6004	WV	933	210	186	5	44	5.0%	15.5%	20.9%
6009	AR	63	21	6	0	26	20.1%	15.0%	24.4%
6016	IL	19	7	3	0	0	26.4%	10.0%	24.4%
6017	IL	9	3	0	0	0	26.4%	10.0%	24.4%
6018	KY	33	7	6	0	0	9.9%	13.9%	23.6%
6019	OH	241	80	55	1	4	15.1%	9.8%	23.7%
6030	ND	2	0	2	0	0	7.7%	10.4%	22.3%
6034	MI	622	150	29	0	32	19.8%	9.7%	23.7%
6041	KY	106	36	10	0	1	9.9%	13.9%	23.6%
6055	LA	16	1	2	0	4	36.1%	17.3%	24.7%
6061	MS	75	11	9	0	5	38.6%	17.6%	25.5%
6064	KS	3189	14	13	0	42	13.8%	8.9%	25.5%
6065	MO	14	2	0	0	2	15.1%	10.6%	23.8%
6068	KS	9	1	0	0	1	13.8%	8.9%	25.5%
6073	MS	511	100	50	5	84	38.6%	17.6%	25.5%
6077	NE	9	3	0	0	0	10.4%	8.9%	25.1%
6082	NY	138	36	14	0	0	32.0%	13.2%	22.3%
6085	IN	82	19	5	0	8	12.5%	8.8%	24.8%
6089	MT	143	0	0	0	0	9.4%	13.3%	22.6%
6090	MN	8	2	1	0	0	10.5%	6.9%	24.2%
6096	NE	1	0	1	0	0	10.4%	8.9%	25.1%
6098	SD	67	16	1	1	1	11.3%	11.4%	24.9%
6101	WY	33	6	2	0	1	8.1%	7.2%	24.0%
6106	OR	0	0	0	0	0	0.0%	0.0%	22.6%

Exhibit U-3

Demographic Data Used to Characterize CCR Landfills

Plant ID	State	Population within One Mile	Population under 18	Population in Poverty	Native American Population	Minority Population (includes Native American)	State Percent Minority	State Percent Poverty	State Percent Under-18
6113	IN	6	0	0	0	0	12.5%	8.8%	24.8%
6136	TX	67	17	9	0	28	29.1%	14.6%	27.3%
6137	IN	585	140	57	0	12	12.5%	8.8%	24.8%
6138	AR	285	75	52	5	33	20.1%	15.0%	24.4%
6139	TX	63	20	5	0	15	29.1%	14.6%	27.3%
6146	TX	57	0	0	0	0	29.1%	14.6%	27.3%
6147	TX	74	4	0	0	0	29.1%	14.6%	27.3%
6165	UT	0	0	0	0	0	10.8%	8.8%	31.5%
6166	IN	38	11	12	0	2	12.5%	8.8%	24.8%
6170	WI	3068	855	94	11	255	11.1%	8.1%	23.6%
6177	AZ	0	0	0	0	0	24.5%	12.5%	25.5%
6179	TX	1	0	0	0	0	29.1%	14.6%	27.3%
6180	TX	4	0	1	0	0	29.1%	14.6%	27.3%
6181	TX	44	11	19	0	32	29.1%	14.6%	27.3%
6183	TX	0	0	0	0	0	29.1%	14.6%	27.3%
6193	TX	64	8	4	0	26	29.1%	14.6%	27.3%
6194	TX	4	0	0	0	4	29.1%	14.6%	27.3%
6195	MO	268	54	21	5	11	15.1%	10.6%	23.8%
6204	WY	20	3	4	0	0	8.1%	7.2%	24.0%
6213	IN	36	3	0	0	5	12.5%	8.8%	24.8%
6248	CO	10	5	5	0	1	17.1%	8.9%	24.4%
6249	SC	141	41	4	0	62	32.7%	12.8%	23.4%
6254	IA	136	28	4	1	2	6.1%	8.3%	23.9%
6264	WV	237	66	29	1	10	5.0%	15.5%	20.9%
6469	ND	0	0	0	0	0	7.7%	10.4%	22.3%
6639	KY	22	6	1	0	0	9.9%	13.9%	23.6%
6641	AR	11	2	0	0	0	20.1%	15.0%	24.4%
6648	TX	4	0	0	0	0	29.1%	14.6%	27.3%
6664	IA	52	13	4	0	9	6.1%	8.3%	23.9%
6761	CO	6	0	0	0	0	17.1%	8.9%	24.4%
6772	OK	0	0	0	0	0	23.9%	13.8%	24.8%
6823	KY	9	1	1	0	2	9.9%	13.9%	23.6%
7030	TX	12	0	1	0	2	29.1%	14.6%	27.3%
7097	TX	47	12	19	0	32	29.1%	14.6%	27.3%
7210	SC	34	9	6	0	18	32.7%	12.8%	23.4%
7213	VA	11	1	1	0	2	27.7%	8.9%	23.2%
7242	FL	20	7	0	1	3	22.1%	11.7%	21.3%
7343	IA	14	1	0	0	1	6.1%	8.3%	23.9%
7790	UT	0	0	0	0	0	10.8%	8.8%	31.5%
7902	TX	6	2	0	0	0	29.1%	14.6%	27.3%
8023	WI	386	102	25	0	17	11.1%	8.1%	23.6%
8042	NC	284	39	4	0	34	27.8%	11.7%	23.9%
8066	WY	0	0	0	0	0	8.1%	7.2%	24.0%
8069	UT	4	0	0	0	0	10.8%	8.8%	31.5%
8102	OH	227	60	16	2	12	15.1%	9.8%	23.7%
8219	CO	16	3	0	1	1	17.1%	8.9%	24.4%

Exhibit U-3

Demographic Data Used to Characterize CCR Landfills

Plant ID	State	Population within One Mile	Population under 18	Population in Poverty	Native American Population	Minority Population (includes Native American)	State Percent Minority	State Percent Poverty	State Percent Under-18
8222	ND	35	0	0	0	0	7.7%	10.4%	22.3%
8223	AZ	0	0	0	0	0	24.5%	12.5%	25.5%
8224	NV	0	0	0	0	0	24.8%	9.4%	24.6%
8226	PA	723	212	67	1	28	14.6%	9.5%	22.0%
10002	CA	0	0	0	0	0	#N/A	#N/A	#N/A
10075	MN	36	8	5	0	0	10.5%	6.9%	24.2%
10151	WV	1479	192	105	0	46	5.0%	15.5%	20.9%
10343	PA	1265	267	148	4	20	14.6%	9.5%	22.0%
10784	MT	16	5	0	3	3	9.4%	13.3%	22.6%
50951	UT	1337	351	254	117	195	10.8%	8.8%	31.5%
55076	MS	58	15	20	0	19	38.6%	17.6%	25.5%
56224	NV	1	0	1	0	0	24.8%	9.4%	24.6%

APPENDIX V

UMRA Written Statement

UMRA Written Statement

I. Introduction

Title II of the 1995 Unfunded Mandates Reform Act (UMRA; 2 U.S.C. 1531-1538) requires Federal agencies, unless otherwise prohibited by law, to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Specifically, Section 202 of UMRA generally requires Federal agencies to prepare a written statement, including a cost-benefit analysis, for each proposed and final rule with "Federal mandates" that may result in expenditures by State, local, and tribal governments, in the aggregate, or to the private sector, of \$100 million or more in any one year. Section 202 requires that "Written Statements" contain five elements of information:

1. An identification of the provision of Federal law under which the rule is being promulgated;
2. A qualitative and quantitative assessment of the anticipated costs and benefits of the Federal mandate, including the costs and benefits to State, local, and tribal governments or the private sector, as well as the effect of the Federal mandate on health, safety, and the natural environment;
3. Estimates by the agency, if and to the extent that the agency determines that accurate estimates are reasonably feasible, of:
 - (a) the future compliance costs of the Federal mandate; and
 - (b) any disproportionate budgetary effects of the Federal mandate upon any particular regions of the nation or particular State, local, or tribal governments, urban or rural or other types of communities, or particular segments of the private sector;
4. Estimates by the agency of the effect on the national economy, such as the effect on productivity, economic growth, full employment, creation of productive jobs, and international competitiveness of United States goods and services, if and to the extent that the agency in its sole discretion determines that accurate estimates are reasonably feasible and that such effect is relevant and material; and
5. Description of the extent of the agency's prior consultation with elected representatives (under section 204) of the affected State, local, and tribal governments, including a summary of the comments and concerns that were presented by State, local, or tribal governments either orally or in writing to the agency; and a summary of the agency's evaluation of those comments and concerns.

This document constitutes the "Written Statement" to meet this requirement for the CCR final rule. The Environmental Protection Agency (EPA) has conducted a cost-benefit analysis for this action, which has been submitted in the docket entitled "Regulatory Impact Analysis" (RIA).

II. Responses to the Five Information Elements

A. Identification of the Provision of Federal Law Under Which the Rule is Being Promulgated

The CCR rule is being promulgated under Subtitle D "State or Regional Solid Waste Plants" of the 1976 Resource Conservation and Recovery Act (RCRA), which amended the 1965 Solid Waste Disposal Act (SWDA).

B. Cost to State, local, and Tribal Governments and the Private Sector

As estimated in the RIA, the rule may affect 478 coal-fired electric utility plants, and may have a nationwide average annualized cost of approximately \$739 million per year (at a 7% discount rate). Of this amount, average annualized costs to State/local governments total \$40.1 million, consisting of estimated regulatory compliance costs for State/local governments that currently own or operate affected coal-fired electric utility plant(s), plus \$1.4 million for State/local government implementation of the rule. The estimated average annualized cost to the private sector ranges totals approximately \$617 million per year. None of the plants are tribally-owned; therefore, EPA does not expect this rule to impose costs on tribal governments.

C. Extent to Which Costs to State, Local, and Tribal Governments May Be Paid By EPA or Other Federal Agencies, or To Which There Are Available Federal/EPA Resources to Carry Out a Federal Intergovernmental Mandate

As of 2011, EPA provides states with \$103 million per year in funding for implementation of RCRA Subtitle C hazardous waste programs in 50 states (AK and IA do not have EPA-authorized RCRA programs).¹ However, EPA does not provide funding to state, local, or tribal governments for implementation of Subtitle D non-hazardous solid waste programs. Therefore it is not likely that EPA may provide state/local governments with additional resources to cover the implementation cost of the rule.

D. Estimates Of Future Compliance Costs And Budgetary Effects On Particular Regions Of The Country, Or Particular State, Local, Or Tribal Governments Or Communities, Or Particular Segments Of The Private Sector

The RIA assessed potential distributional effects of the CCR rule cost impacts on:

- Future electricity prices on a state-by-state and on a national aggregate basis;
- A state-by-state regulatory cost sub-total basis;
- Small entity cost sub-total basis;
- Minority and low-income population basis living near affected electric utility plants;
- Child populations living near affected electric utility plants; and
- State/local government cost sub-total basis.

E. Extent of EPA's Prior Consultation with Affected State, Local, and Tribal Governments

¹ EPA's funding to state governments is in the form of "formula grants" under the Hazardous Waste Management State Program Support, Number: 66.801; see the Catalog of Federal Domestic Assistance at: <https://cfda.symplicity.com/index?s=main&mode=list&tab=list>

In developing the two co-proposed “Subtitle C” and “Subtitle D” regulatory options for the CCR rule, which EPA proposed on June 21, 2010,² EPA consulted with small governments according to EPA’s UMRA interim small government consultation plan developed pursuant to section 203 of UMRA. EPA’s interim plan provides for two types of possible small government input: technical input and administrative input. According to this plan, and consistent with section 204 of UMRA, early in EPA’s 2009 process for developing the CCR rule, EPA implemented a small government consultation process consisting of two consultation components:

1. The following series of year 2009 meetings for purpose of acquiring small government technical input: (1) February 27 with the Association of State and Territorial Solid Waste Management Officials (ASTSWMO) Coal Ash Workgroup (Washington DC), (2) March 22-24 with the Environmental Council of States (ECOS) Spring Meeting (Alexandria VA), (3) April 15-16 with the ASTSWMO Mid-Year Meeting (Columbus OH), (4) May 12-13 with the EPA Region IV State Directors Meeting (Atlanta, GA), (5) June 17-18 with the ASTSWMO Solid Waste Managers Conference (New Orleans, LA), (6) July 21-23 with the ASTSWMO Board of Directors Meeting (Seattle, WA), and (7) August 12 with the ASTSWMO Hazardous Waste Subcommittee Meeting (Washington DC). ASTSWMO is an organization with a mission to work closely with the EPA to ensure that its state government members are aware of the most current developments related to their state waste management programs. ECOS is a national non-profit, non-partisan association of state and territorial environmental agency leaders. As a result of these meetings EPA received letters in mid-2009 from 22 state governments as well as a letter from ASTSWMO expressing their stance on CCR regulatory options.
2. Contact letters mailed August 24, 2009 to the following 10 organizations representing small government elected officials, to inform them and seek their input for the rule development, as well as to invite them to a meeting held September 16, 2009 in Washington DC: (1) National Governors Association, (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) County Executives of America, (7) National Association of Counties, (8) International City/County Management Association, (9) National Association of Towns and Townships, and (10) Environmental Council of the States. These 10 organizations of small government elected officials are identified in EPA’s November 2008 Federalism guidance as the “Big 10” organizations appropriate to contact for purpose of consultation with small government elected office.

² CCR proposed rule: “Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals From Electric Utilities,” Federal Register, Vol. 75, No. 118, June 21, 2010, pages 35128 to 35264.

Appendix W

Identity of Organizations Which Submitted Public Comments Related to EPA's RIA for the 2010 Proposed CCR Rule

- **Exhibit W-1: 431 Organizations Which Submitted Comments During the June 21, 2010 to November 19, 2010 Public Comment Period for EPA's June 21, 2010 Proposed CCR Rule**
- **Exhibit W-2: 170 Organizations Which Submitted Comments at EPA's Eight Public Hearings on the June 21, 2010 Proposed CCR Rule (Held Between August 30 and October 27, 2010)**

Note: Counts of organizations in both Exhibits reflect unique combined counts of both (a) organization name, and (b) spokesperson name; thus the resultant total counts reflect more than one count for some organizations with more than one spokesperson submitting comments.

Exhibit W-1

431 Organizations Which Submitted Comments During the June 21, 2010 to November 19, 2010 Public Comment Period for the June 21, 2010 Proposed CCR Rule

	Organization or Individual	Spokesperson	Organization Type	Count of comments
1	Abode Check, LLC	Thomas E. Murley	Other Company	1
2	Airplaco Equipment Company	Todd Ferguson	Beneficial User	2
3	Alabama Coal Association (ACA)	David Roberson	Trade Association	4
4	Alabama Environmental Council	Michael J. Churchman	Advocacy Group	3
5	Alabama Public Service Commission	John D. Free	State Government	7
6	Alabama Pulp & Paper Council	Roy McAuley	Trade Association	5
7	Alcoa Inc.	Curt Wells	Other Company	2
8	Alstom Power, Inc.	Robert G. Hilton	Other Company	1
9	American Coal Ash Association (ACAA)	Thomas H. Adams	Trade Association	6
10	American Coal Council (ACC)	Janet Gellici	Trade Association	4
11	American Coalition for Clean Coal Electricity (ACCCE)	Paul Bailey	Advocacy Group	1
12	American Electric Power (AEP)	John M. McManus	Electric Utility Company	1
13	American Forest and Paper Association (AF&PA)	Paul Noe	Trade Association	3
14	American Public Power Association (APPA)	Theresa Pugh	Trade Association	4
15	American Road and Transportation Builders Association (ARTBA)	T. Peter Ruane	Trade Association	1
16	ANJ Transport, Inc.	F. Stephen Thomas	Beneficial User	1
17	Anonymous	Anonymous	Anonymous	1
18	ARIPPA	Jeff A. McNelly	Trade Association	11
19	Arizona Chamber of Commerce and Industry	Rebecca Hudson on behalf of Glenn Hamer	Trade Association	1
20	Arizona Department of Environmental Quality (ADEQ)	Benjamin H. Grumbles	State Government	2
21	Arizona Electric Power Cooperative, Inc.	Theresa D. Legere	Electric Utility Company	1
22	Arizona Public Service Company (APS)	Scott Davis	Electric Utility Company	1
23	Arizona Rock Products Association (ARPA)	Steve Trussell	Trade Association	2
24	Arkansas Electric Cooperative Corporation (AECC)	Jonathan Oliver	Electric Utility Company	2
25	Arkansas River Power Authority (ARPA)	William Y. Leung	Electric Utility Company	1
26	Ash Development Association of Australia (ADAA)	Craig Heidrich	Trade Association	1
27	Ashland Casting Solutions (Ashland)	Lee R. Horvath	Beneficial User	2
28	AspenGold Consulting, LLC	Kristopher J. Johnson	Beneficial User	1
29	Asphalt Roofing Manufacturers Association (ARMA)	Reed Hitchcock	Trade Association	2
30	Associated Electric Cooperative, Inc. (AECI)	Brent Ross	Electric Utility Company	1
31	Associated General Contractors of America (AGC)	Melinda L. Tomaino	Trade Association	1
32	Association of State and Territorial Solid Waste Management Officials (ASTSWMO)	Stephen A. Cobb (Al)	State Government	1
33	Association of State and Territorial Solid Waste Management Officials (ASTSWMO)	Mary T. Zdanowicz	State Government	4
34	Avista Corp.	Darrell Soyars	Electric Utility Company	2
35	B&G Materials	Robert L. Beck	Beneficial User	1
36	Basin Electric Power Cooperative (BEPC)	Claire M. Olson	Electric Utility Company	2
37	Bayview Redi-Mix, Inc.	Marvin Prince	Beneficial User	2
38	Belmont Aggregates, Inc.	John S. Kish	Beneficial User	1
39	Beneficial Reuse Management, LLC	Robert C. Spoerri	Beneficial User	1
40	Bert & Wetta Abilene, Inc.	Stan Foltz	Beneficial User	2
41	Birchwood Power Partners, L.P.	Julie Caiafa	Electric Utility Facility	5
42	Bismarck-Mandan Chamber of Commerce	Kelvin L. Hullet	Trade Association	2
43	Black Warrior Riverkeeper, Inc.	Eva Dillard	Advocacy Group	1
44	BNSF Railway Company (BNSF)	Brendan Lowrey	Beneficial User	2
45	Bode Concrete LLC	Dennis Broderick	Beneficial User	1
46	Boral Material Technologies Inc. (BMTI)	John Scoggan	Beneficial User	1
47	Bryan Texas Utilities (BTU)	Dan Wilkerson	Electric Utility Company	1
48	Buckeye Aggregates, Inc.	Gene M. Kiral	Beneficial User	1
49	Buckeye Power, Inc.	Patrick O'Loughlin	Electric Utility Company	1
50	Bull Concrete	Adam Pinto	Beneficial User	2
51	Business Council of Alabama (BCA)	David Roberson	Trade Association	1
52	BVU Anthony	Wes Rosenbalm	Electric Utility Company	2
53	C&C Ready Mix Corporation		Beneficial User	1
54	C&C Ready Mix Corporation	Nicholas Cerretani	Beneficial User	1
55	Cape Cod Ready Mix	Steve Berlo	Beneficial User	1
56	Center for Progressive Reform, University of Maryland School of Law	Rena Steinzor	Advocacy Group	15
57	Central Alabama Electric Cooperative	Terry Miller	Electric Utility Company	4
58	Ceramatec Inc.	Anthony Nickens	Beneficial User	1
59	CertainTeed Gypsum, Inc.	Lauren P. Alterman	Beneficial User	12
60	Charah, Inc.	Charles Price	Beneficial User	2

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431 Organizations Which Submitted Comments During the June 21, 2010 to November 19, 2010 Public Comment Period for the June 21, 2010 Proposed CCR Rule

	Organization or Individual	Spokesperson	Organization Type	Count of comments
61	Choctaw County Economic Development District (CCEDD), Mississippi	T. Alan Bates	Local Government	1
62	Choctaw County, Oklahoma, Board of County Commissioners	Danny Antwine	Local Government	1
63	Chugach Electric Association, Inc.	Bradley W. Evans	Electric Utility Company	1
64	Citizens Against Ruining the Environment	Ellen Rendulich and Sandy Burcenski	Advocacy Group	1
65	Citizens Against Ruining the Environment (C.A.R.E.)	Carol Stark et al.	Advocacy Group	1
66	City of Lamar Utilities Board	Robert Schemahorn	Electric Utility Facility	2
67	City of Merriam, Kansas	Hye Jin Lee	Local Government	2
68	City of Morristown, Tennessee	Barbara C. Barile	Local Government	2
69	City of Sheffield, Alabama	Ian T. Sanford	Local Government	1
70	Civil & Environmental Consultants, Inc. (CEC)	Jeremy S. Ousley	Beneficial User	1
71	CK Transport	Chuck Kitchens	Beneficial User	2
72	Clean Water Network	Natalie Roy	Advocacy Group	1
73	Cleco Corporation	Bill Matthews	Electric Utility Company	1
74	Cliffs Natural Resources Inc. (Cliffs)	David Z. Skolasinski	Other Company	8
75	Coal Slag Consortium	Sean Todd	Trade Association	1
76	Coastal Drilling	Doug Banks	Beneficial User	1
77	Coastwide Ready-Mix	Dennis Johnson	Beneficial User	1
78	Colonial Construction Inc	Paul Bigness	Beneficial User	1
79	Colorado Department of Public Health and Environment	Charles G. Johnson on behalf of Joe Schieffelin	State Government	2
80	Colorado Springs Utilities	Michael P. Brady	Electric Utility Company	1
81	Colstrip Energy Limited Partnership (CELP)	R. Lee Roberts	Electric Utility Facility	1
82	Comite Dialogo Ambiental	Ruth Santiago	Advocacy Group	2
83	Commerce Lexington Inc.	Tyler Campbell	Trade Association	2
84	Commonwealth of Pennsylvania House of Representatives	Jessica R. Guyer on behalf of Scott E. Hutchinson	State Elected Official	1
85	Conco Companies - Ready Mix Division/ACME	Gaylene Anderson on behalf of John Holiman	Beneficial User	2
86	Concrete Placing Company, Inc.	Jon Berger	Beneficial User	1
87	Connecticut Ready Mixed Concrete Association, Inc. (CRMCA)	Kevin Miller	Trade Association	2
88	Constellation Energy	Charlene Zaruba on behalf of Paul Allen	Electric Utility Company	4
89	Construction Aggregates of West Virginia, L.L.C.	Jerri V. Kiral	Beneficial User	1
90	Construction Materials Recycling Association	William Turley	Trade Association	1
91	Consumers Energy Company	Gary A. Dawson	Electric Utility Company	2
92	Conti Materials Service, LLC	Gene Conti	Beneficial User	1
93	Coresco, LLC	Carrie D. Lilly	Beneficial User	2
94	Council of Industrial Boiler Owners (CIBO)	Robert D. Bessette	Trade Association	7
95	CPS Energy	Michael M. Malone	Electric Utility Company	3
96	Cranesville Block Company, Inc.	John Tesiero	Beneficial User	2
97	Croell Redi-Mix, Inc.	Harlan Taylor	Beneficial User	2
98	Cross Creek Cattle, Inc.	Greg Hayes	Beneficial User	1
99	Crouse Electric, Inc.	David Lawrence on behalf of Paul Crouse	Beneficial User	1
100	Dale Nash Hauling Inc.	Dale Nash	Beneficial User	1
101	Dayton Power & Light Company (DP&L)	JoAnne Rau	Electric Utility Company	1
102	Department of Electric, City of Hamilton, Ohio	Charles Young	Electric Utility Company	8
103	Department of Water and Power the City of Los Angeles (LADWP)	Eric J. Tharp and Mark J. Sedlacek	Electric Utility Company	1
104	Deseret Generation and Transmission Co-operative	Howard Vickers	Electric Utility Company	3
105	Detroit Regional Chamber	Brian A. Kandler	Trade Association	1
106	Dixie Electric Cooperative	Gary Harrison	Electric Utility Company	3
107	Dominion Resources Services, Inc.	Lisa J. Keck on behalf of Pamela Faggert	Electric Utility Company	1
108	Dredging Inc. (doing business as) Scott's Concrete	Jane E. Martin	Beneficial User	1
109	Duke Energy	Mike Stroben	Electric Utility Company	18
110	Dunham Price, LLC (submitted on behalf of Dunham Price by Headwaters Resources)	George Thompson	Beneficial User	1
111	Dynegy Inc	Ben C. Trammell	Electric Utility Company	2
112	Earth Justice, et. al. (prepared for Sierra Club, Earthjustice, Natural Resources Defense Council)	Richard C. Fortuna	Advocacy Group	1
113	Earthjustice et. al.	Lisa Evans	Advocacy Group	91
114	Earthjustice, et. al.	Emily Greenlee on behalf of Lisa Evans	Advocacy Group	2
115	East Kentucky Power Cooperative (EKPC)	Jerry Purvis	Electric Utility Company	7

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431 Organizations Which Submitted Comments During the June 21, 2010 to November 19, 2010
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	Organization or Individual	Spokesperson	Organization Type	Count of comments
116	Edgerton Contractors, Inc.	Peter Davis	Beneficial User	1
117	Edison Mission Energy, LLC	Basil G. Constantelos	Electric Utility Company	3
118	Elastizell Corporation of America	Ned Glysson	Beneficial User	1
119	Electric Power Generation Association	Douglas L. Biden	Trade Association	1
120	Electric Power Research Institute (EPRI)	Ken Ladwig	Trade Association	31
121	Elite Ready Mix	Greg Bridges	Beneficial User	1
122	Empire District Electric Company	George G. Thullesen	Electric Utility Company	2
123	Enduracon Technologies	Larry Nelson	Beneficial User	2
124	Entergy Services, Inc.	Joseph Hantz	Electric Utility Company	2
125	Environmental Council of the States (ECOS)	Lia Parisien on behalf of John W. Mitchell	State Government	4
126	Environmental Council of the States (ECOS)	R. Steven Brown	State Government	2
127	Ernst Concrete of Georgia	David R. Ernst	Beneficial User	1
128	Errcive, Inc.	C. Eric Ramberg	Beneficial User	1
129	Eutaw Construction Company, LLC	William E. Cox	Beneficial User	1
130	Exelon Power	Victoria K. Will	Electric Utility Company	1
131	F. H. Stickles & Son Inc.	Mark Stickles	Beneficial User	1
132	Ferndale Ready Mix & Gravel, Inc.	Keith Korthuis	Beneficial User	1
133	First Energy Corporation	Michael L. Horvath	Electric Utility Company	1
134	Florida Department of Environmental Protection (FDEP)	Richard B. Tedder on behalf Mary Jean Yon	State Government	1
135	Florida Electronic Power Coordinating Group, Inc. (FCG)	Carl Eldred	Electric Utility Company	3
136	FLSmith, Inc.	Ove L. Jepsen	Other Company	1
137	FlyAshDirect	James H. Irvine	Beneficial User	2
138	Folsom Ready Mix, Inc.	Randy Barnes	Beneficial User	1
139	Frank C. Alegre Trucking	Robert A. Fowler	Beneficial User	1
140	Garland Power & Light (GPL)	Ray Schwertner	Electric Utility Facility	1
141	Garrett & Moore, Inc.	Bernie Garrett	Other Company	1
142	GDF SUEZ Energy Generation North America	Bradley J. Cooley	Electric Utility Company	1
143	Geneva Rock Products, Inc.	Jay H. Ritchie	Beneficial User	1
144	Georgia Department of Natural Resources (GAEPD)	Jim Brown for Mark Smith	State Government	2
145	Geosyntec Consultants	John Seymour	Other Company	1
146	Geosynthetic Institute	Robert M. Koerner	Trade Association	1
147	Gibbco, Inc.	Bruce N. Kazich	Beneficial User	4
148	Glasgow EPB	William J. Ray	Electric Utility Company	1
149	Grand River Dam Authority	Charles J. Barney	Beneficial User	1
150	Granger III and Associates, LLC (Granger)	Ralph Nurenberg	Beneficial User	3
151	Granite Construction Incorporated	Robert Swango	Beneficial User	2
152	Graniterock	Greg Diehl	Beneficial User	1
153	Great Lakes Concrete Products, LLC	Rosanne DiPizio	Beneficial User	2
154	Great River Energy	Erik Silvola	Electric Utility Company	4
155	Greater Phoenix Chamber of Commerce	Todd Sanders	Trade Association	1
156	Green Century Capital Management	Kristina Curtis	Other Company	4
157	Green Delaware	Alan Muller	Advocacy Group	2
158	Greenleaf Environmental Services, LLC	David A. Wheeler	Beneficial User	1
159	Gresham Transfer, Inc.	Tom Welch	Beneficial User	2
160	Gypsum Association	Michael Gardner	Trade Association	4
161	H&K Enterprises	Dave Baker	Beneficial User	1
162	H.G. Fredriksen Company, Inc.	H.G. Fredriksen III	Beneficial User	1
163	Hanson Aggregates, LLC	Scott Dickson	Beneficial User	1
164	Harsco Minerals International, a division of Harsco Corporation	Gene Iannazzo	Beneficial User	1
165	Headwaters Resources, Inc.	William H. Gehrmann	Beneficial User	2
166	Heartland Consumers Power District	Eli D. Eilbott	Electric Utility Company	2
167	Honigman Miller Schwartz and Cohn LLP on behalf of Lansing Board of Water and Light (LBWL) and Michigan State University (MSU)	Jeffrey L. Woolstrum	Electric Utility Company	3
168	Hoosier Energy Rural Electric Cooperative (REC), Inc.	Michalene Reilly	Electric Utility Company	2
169	Howard Concrete Pumping Company, Inc.	Joseph E. Bonetti	Beneficial User	1
170	Illinois Municipal Electric Agency (IMEA), (IPEA), (IMUA)	Ronald D. Earl	Electric Utility Company	1
171	Improving Kids' Environment	Jodi Perras	Advocacy Group	2
172	Indiana Economic Development Association (IEDA)	William A. Dory	Trade Association	1
173	Indiana Manufacturers Association, Inc. (IMA)	Patrick Bennett	Trade Association	1
174	Indiana Office of Utility Consumer Counselor	A. David Stippler	State Government	2
175	Institute for Policy Integrity	Jason A. Schwartz	Advocacy Group	8
176	Institute for Study of Economics and the Environment, Lindenwood University	Kenneth W. Chilton	Academia	1
177	Intermountain Construction & Materials	Tony Clobes	Beneficial User	1

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431 Organizations Which Submitted Comments During the June 21, 2010 to November 19, 2010
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	Organization or Individual	Spokesperson	Organization Type	Count of comments
178	Intermountain Power Agency (IPA)	James A. Hewlett	Electric Utility Company	1
179	Intermountain Power Service Corporation (IPSC)	Jon A. Finlinson	Electric Utility Company	3
180	International Brotherhood of Electrical Workers	Ronald Moore	Union	1
181	Interstate Life Power and Light Company (IPL) and Wisconsin Power and Light Company (WPL)	Kathleen A. Lipp	Electric Utility Company	3
182	Interstate Mining Compact Commission (IMCC)	Gregory E. Conrad	State Government	1
183	Inter-Tribal Council of Michigan Inc.	Robin Clark	Tribal Government	3
184	Iowa Association of Business and Industry (ABI)	Michael Ralston	Trade Association	1
185	Iowa Department of Natural Resources (IDNR)	Wayne Gieselman	State Government	1
186	J. P. Noonan Transportation	Bruce Voight	Beneficial User	1
187	Jack B. Parson Companies (JBP)	Bob Rowberry	Beneficial User	1
188	JE Hill Precast	Harley E. Northup	Beneficial User	1
189	Joe Neason Contracting	Joe Neason	Beneficial User	1
190	Kansas City Board of Public Utilities (BPU)	John Pettey	Electric Utility Company	1
191	Kansas Department of Health and Environment	William L. Bider	State Government	2
192	Kanta Products, Inc.	Tom Kanta	Beneficial User	1
193	Kentuckians For The Commonwealth (KFTC)	Nancy L. Reinhart	Advocacy Group	5
194	Kentucky Association of Manufacturers (KAM)	Karen F. Ellis on behalf of Charles Gregory Higdon	Trade Association	2
195	Kentucky Department for Environmental Protection	R. Bruce Scott	State Government	9
196	Kerkstra Precast	Tim Skiba	Beneficial User	1
197	KMR Concrete, Inc.	Tim Fletcher	Beneficial User	5
198	L.G. Everist, Inc.	Richard A. Everist	Beneficial User	1
199	LA Ash, Inc.	Danielle King	Beneficial User	2
200	Labadie Environmental Organization	Ginger Gambaro	Advocacy Group	1
201	Lafayette Utilities System	Lisa G. Dowden and Steven C. Pearson	Electric Utility Facility	2
202	Lansing Board of Water & Light (BWL)		Electric Utility Company	3
203	Lansing Board of Water and Light (BWL) and Michigan State University (MSU)	Jeffrey L. Woolstrum	Electric Utility Company	20
204	LB Industrial Systems, L.L.C.	Mark Konzal	Beneficial User	1
205	LeGrand Johnson Construction Co.	name illegible	Beneficial User	1
206	LeGrand Johnson Construction Co.	Dick Sackett	Beneficial User	1
207	Lehigh Hanson Inc.	Timothy L. Matz	Beneficial User	1
208	Lehigh University	Sean Parrott and Dr. Dork Sahagian	Academia	1
209	Lexington Concrete and Block	Watt Ervin	Beneficial User	3
210	LG&E and KU Energy LLC	Robert J. Ehrler on behalf of Dorothy E. O'Brien	Electric Utility Company	2
211	Liebe Trucking, Inc.	Sara Liebe on behalf of Gary Liebe	Beneficial User	1
212	Lifetime Composites LLC	Edward J. Butteriss	Beneficial User	1
213	Lignite Energy Council	John W. Dwyer	Trade Association	2
214	Little Village Environmental Justice Organization (LVEJO)	Keith Harley	Advocacy Group	6
215	Louisiana Public Service Commission	Eve Kahao Gonzalez	State Government	4
216	Lower Colorado River Authority (LCRA)	Henry Eby	Electric Utility Facility	4
217	Manitowoc Public Utilities (MPU)	Nilaksh Kothari	Electric Utility Facility	4
218	Manufacture Alabama	Blake Hardwich on behalf of Mike Conlon	Trade Association	2
219	Maryland Department of the Environment (MDE)	Shari T. Wilson	State Government	1
220	Masonry Wall Systems	Alan C. Ferguson	Beneficial User	1
221	Mass Comment Campaign sponsoring by Earthjustice (165 signatures) Part 1 of 2		Advocacy Group	1
222	Mass Comment Campaign sponsoring organization unknown (47)		Private Citizen	4
223	Massachusetts Department of Environmental Protection	James C. Colman	State Government	6
224	Materials Handling and Transportation	Name illegible	Beneficial User	2
225	Mathis-Akins Concrete Block Co. Inc	Tina Sheffield Kuncaitis	Beneficial User	2
226	Mathis-Akins Concrete Block Co., Inc.	Alice S. Kuncaitis	Beneficial User	2
227	MBO Precast, Inc.	Jeffrey Opachinski	Beneficial User	1
228	McDonald Farms Enterprises	Marjorie McDonald	Beneficial User	2
229	McMahon Contracting, L.P.	Shawn McMahon	Beneficial User	1
230	MeadWestvaco	Dirk J. Krouskop	Beneficial User	2
231	Memphis Ready-Mix	Phillip Palczer	Beneficial User	1
232	Metro Ready Mix	W. Ryan Skidmore	Beneficial User	1
233	Metro Ready Mix Concrete (MRM)	Steve Herron	Beneficial User	1
234	Mettiki Coal, LLC	James C. Ashby	Beneficial User	1
235	Michie Corporation	Jessica Michie	Beneficial User	1

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431 Organizations Which Submitted Comments During the June 21, 2010 to November 19, 2010 Public Comment Period for the June 21, 2010 Proposed CCR Rule

	Organization or Individual	Spokesperson	Organization Type	Count of comments
236	Michigan Chamber of Commerce	Doug Roberts	Trade Association	4
237	Michigan Manufacturers Association	Randall Gross	Trade Association	1
238	MidAmerican Energy Holdings Company (MidAmerican)	Cathy S. Woollums	Electric Utility Company	2
239	Miles Sand and Gravel Company	Jerry Trudeau	Beneficial User	1
240	Mineral Resource Technologies, Inc.	Jeffrey G. Dusseault	Beneficial User	1
241	Minnesota Chamber of Commerce	Michael Robertson	Trade Association	1
242	Minnesota Power (ALLETE)	Michael G. Cashin	Electric Utility Company	2
243	Minnkota Power Cooperative, Inc. (Minnkota)	John T. Graves	Electric Utility Company	1
244	Missoula Concrete Construction	Douglas G. Bauer	Beneficial User	1
245	Missouri Department of Natural Resources	Robert Stout on behalf of Dru Buntin	State Government	3
246	Missouri Joint Municipal Electric Utility Commission	Floyd Gilzow	State Government	4
247	Moapa Band of Paiutes	Darren Daboda	Tribal Government	1
248	Mobile Abrasives - Alabama	Edward J. Serda	Beneficial User	2
249	Montana-Dakota Utilities Company (Montana-Dakota)	Abbie Krebsbach	Electric Utility Company	1
250	Morandin Concrete	Tippy Cosuello	Beneficial User	1
251	Nagy Concrete Company	Steve Simpson	Beneficial User	1
252	National Association of Manufacturers	Keith W. McCoy	Trade Association	4
253	National Concrete Masonry Association (NCMA)	Robert D. Thomas	Trade Association	2
254	National Council of Coal Lessors (NCCL)	Nick Carter	Trade Association	2
255	National Ready Mixed Concrete Association (NRMCA)	Robert A. Garbini	Trade Association	4
256	National Rural Electronic Cooperative Association (NRECA)	James F. Stine	Trade Association	5
257	National Tribal Air Association (NTAA)	Bill Thompson	Tribal Government	4
258	Native Community Action Council (NCAC)	Ian Zabarte	Advocacy Group	1
259	Navajo Tribal member	L. Goodman	Tribal Government	1
260	Nebraska Ash Company	L. E. "Tex" Leber	Beneficial User	2
261	Nevada Department of Conservation and Natural Resources, Nevada Division of Environmental Protection (NDEP)	Collen Cripps	State Government	2
262	New York Construction Materials Association (NY Materials)	David S. Hamling	Trade Association	3
263	New York State Department of Transportation (NYSDOT)	Donald A. Streeter on behalf of Gary A. Frederick	State Government	1
264	NiSource Corporate Services	Dale A. Helmers	Electric Utility Company	3
265	No organization provided	Annelly Noble	Private Citizen	2
266	No organization provided	Clint Wald	Private Citizen	2
267	No organization provided	David E. Lawrence	Private Citizen	1
268	No organization provided	Fred Hooper	Beneficial User	1
269	No organization provided	Gene Daniel, P.E.	Private Citizen	1
270	No organization provided	James J. Rohrbach, P.E.	Private Citizen	2
271	No organization provided	Jared Sommer, Ph.D.	Private Citizen	1
272	No organization provided	Jerry Dart	Private Citizen	1
273	No organization provided	Jim Cox	Private Citizen	1
274	No organization provided	Kristina Keeling	Private Citizen	1
275	No organization provided	Larry D. Conley	Private Citizen	1
276	No organization provided	Mark Morgan	Private Citizen	1
277	No organization provided	Nick Mankle	Private Citizen	2
278	No organization provided	Antoinette Stein	Private Citizen	1
279	No organization provided	Bruce Boggs	Private Citizen	1
280	No organization provided	Chris Barnes	Private Citizen	3
281	No organization provided	Norman E. Divers	Private Citizen	1
282	No organization provided	Paul Benedict	Private Citizen	1
283	No organization provided	Rafic Minkara, Ph.D., P.E.	Private Citizen	6
284	No organization provided	Raymond von Drehle	Private Citizen	1
285	No organization provided	Renee Reber	Private Citizen	1
286	Norfolk Southern Corporation	James A. Hixon	Beneficial User	1
287	North American Concrete Alliance (NACA)	David Hubbard on behalf of North American Concrete Alliance (NACA)	Trade Association	2
288	North American Drilling	John Mayfield	Beneficial User	1
289	North Dakota Department of Health	L. David Glatt	State Government	4
290	Northern Concrete Pipe Inc	Bill Washabaugh	Beneficial User	1
291	Novinda Corporation	William D. Byers on behalf of Michael P. Maloney	Beneficial User	1
292	NRG Energy Inc.	Verne Shortell	Electric Utility Company	1
293	Offshore Express, Inc.	Marcia Mann on behalf of Scott Kisilywicz	Other Company	2
294	Oglethorpe Power Corporation	Douglas J. Fulle	Electric Utility Company	2
295	Ohio Coal Association	Michael T.W. Carey	Trade Association	6

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431 Organizations Which Submitted Comments During the June 21, 2010 to November 19, 2010 Public Comment Period for the June 21, 2010 Proposed CCR Rule

	Organization or Individual	Spokesperson	Organization Type	Count of comments
296	Ohio Department of Transportation	Juliet Denniss	State Government	1
297	Old Dominion Electric Cooperative (ODEC)	Lisa D. Johnson	Electric Utility Company	1
298	Orangeburg Redi-Mix Concrete, Inc.	J. C. Till	Beneficial User	2
299	Organic and Mineral Systems Inc.	Timothy J. Nicholson	Beneficial User	1
300	Otter Tail Power Company	Farren Richard	Electric Utility Company	2
301	Otter Tail Power Company	W. Uggerud	Electric Utility Company	1
302	Owensboro Municipal Utilities	Kevin D. Frizzell	Electric Utility Company	2
303	Palmetto Agribusiness Council (PABC)	Bob Battle	Trade Association	1
304	Paramount Ready Mix	Charles J. Oliver	Beneficial User	1
305	Partners Bulk Logistics (PBL)	Ron Heller	Beneficial User	2
306	Pennsylvania Coal Association (PCA)	Josie Gaskey	Trade Association	2
307	Pennsylvania Legislature	Holly Stimely on behalf Timothy J. Solobay	State Elected Official	1
308	Peterson Gravel & Ready Mix, Inc.	Cindy Peterson	Beneficial User	1
309	Phoenix Cement Company	Verle C. Martz	Beneficial User	1
310	Phoenix Cement Company (PCC), Salt River and Rock, Salt River Materials Group	Roger R. Smith	Beneficial User	3
311	PMI Ash Technologies, LLC (PMI)	Lisa I. Cooper	Beneficial User	16
312	Pocatello Ready Mix	C. Michael Horrocks	Beneficial User	1
313	Port Aggregates, Inc.	James P. Guinn Sr.	Beneficial User	3
314	Portland Cement Association	Robert Hirsch	Trade Association	6
315	PowerSouth Energy Cooperative	Dr. Keith Stephens	Electric Utility Company	1
316	Pozzi-Tech, Inc.	Terry E. Watson	Beneficial User	3
317	Prairie Rivers Network, Illinois Chapter of the Sierra Club, American Bottom Conservancy	Traci L. Barkley	Advocacy Group	1
318	Prairie State Generating Company, LLC (PSGC)	Keith Bastian	Electric Utility Company	5
319	Precast/Prestressed Concrete Institute (PCI)	James G. Toscas	Trade Association	3
320	Professional Engineering Consultants (PEC)	Wes Britson	Beneficial User	3
321	Progress Energy, Inc.	Caroline Choi	Electric Utility Company	2
322	PSEG Power LLC and Public Service Electric and Gas	Eric B. Svenson	Electric Utility Company	1
323	Public Service Commission (PSC) - State of North Dakota	Tony Clark	State Government	3
324	Public Service Company of New Hampshire (PSNH)	William H. Smagula	Electric Utility Company	3
325	Public Utilities Commission of Ohio	Rebecca L. Hussey	State Government	13
326	RAC Brokerage, LLC	Ron Carter	Beneficial User	2
327	Restore Painting & Waterproofing, Inc.	Brenda Camacho on behalf of Norge Araniz	Beneficial User	2
328	Revolutionary Plastics, LLC, Steven G. Barringer and Tasha M. Newland, Holland & Hart LLP	on behalf of Revolutionary Plastics	Beneficial User	2
329	Rob Carryl		Beneficial User	1
330	Rochester Public Utilities (RPU)	Larry J. Koshire	Electric Utility Company	2
331	Rock Transport, Inc.	Dick Peterson	Beneficial User	1
332	RRI Energy Inc.	S. Dixon	Electric Utility Company	1
333	Rustin Concrete	Barton L. Rustin	Beneficial User	1
334	Saint-Gobain Corporation / CertainTeed Corporation	Lauren P. Alterman	Beneficial User	4
335	Salt River Project (SRP)	Daniel J. Casiraro	Electric Utility Company	2
336	San Miguel Electric Cooperative, Inc. (San Miguel)	Joseph G. Eutizi	Electric Utility Company	2
337	Santee Cooper	Jay Hudson	Electric Utility Company	1
338	SCANA Corporation	Shirley M. Ruffin	Electric Utility Company	2
339	Seminole Electric Cooperative, Inc. (Seminole)	Carl Eldred	Electric Utility Company	3
340	Semo, Ready Mix, Inc.	Steven R. Obermann	Beneficial User	1
341	Separation Technologies LLC	James Bittner	Beneficial User	1
342	Sidney Red-E-Mix, Inc.	Travis Peterson	Beneficial User	1
343	Sierra Club - Las Vegas Field Office	Vinny Spotleson	Advocacy Group	1
344	Silica Fume	Drew DeCarlo	Beneficial User	1
345	Simon Contractors Company	John Hodge	Beneficial User	1
346	Small Business Administration's Office of Advocacy (SBA)	Winslow Sargeant	Federal Agency	4
347	South Carolina Chamber of Commerce, Environmental Technical Committee	David M. Comen	Trade Association	2
348	South Carolina Department of Agriculture	Hugh E. Weathers	State Government	2
349	South Carolina Department of Health and Environmental Control	Daphne Neel	State Government	1
350	South Carolina Manufacturers Alliance (SCMA)	Lewis F. Gossett	Trade Association	1
351	South Carolina Office of Regulatory Staff (ORS)	Florence P. Belser	State Government	3
352	Southern Company	Chris M. Hobson	Electric Utility Company	2
353	Southern Company behalf of itself and its four subsidiaries: Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company	Chris M. Hobson	Electric Utility Company	7
354	Southern Crushed Concrete LLC	James R. Miller Jr.	Beneficial User	1

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355	Southern Illinois Motor Xpress, Inc.	Terry D. Oetjen	Beneficial User	2
356	Southern Illinois Power Cooperative	Leonard F. Hopkins	Electric Utility Company	1
357	Specialized Transport LLC	Christopher D. Benna	Beneficial User	3
358	Specialty Materials, Inc.	Dot McClurg	Beneficial User	2
359	Sphere One, Inc.	Ryan M. Brownhill	Beneficial User	1
360	SSE, Inc.	Timothy R. Unger	Beneficial User	1
361	Standard Cements Materials, Inc.	Mario A. Tamez	Beneficial User	2
362	State of Alaska	Kristin J. Ryan	State Government	1
363	State of Pennsylvania Department of Environmental Protection	Todd M. Wallace	State Government	4
364	Stinson Morrison Hecker LLP on behalf of Kansas City Board of Public Utilities	Parthenia B. Evans and Dennis Lane	Electric Utility Company	11
365	Stone Restoration of America	Adam Babbidge	Beneficial User	1
366	Structural Design Group, Inc. (SDG)	Michael Davis	Beneficial User	1
367	Structural Rehabilitation Group, LLC	Kirby L. McCleary	Beneficial User	3
368	Sunflower Electric Power Corporation	Paul E. Reynolds	Electric Utility Company	5
369	System Council U-19 IBEW	Bill Frederick	Union	1
370	Tennessee Department of Environment and Conservation (TDEC)	Paul L. Sloan	State Government	16
371	Tennessee Riverkeeper, Inc.	David Whiteside	Advocacy Group	2
372	Tennessee Valley Authority	John W. Myers	Electric Utility Company	3
373	Tennessee Valley Public Power Association, Inc. (TVPPA)	Jack W. Simmons	Electric Utility Company	4
374	Texas Aggregates & Concrete Association (TACA)	R. Szecsy	Trade Association	1
375	Texas Coal Combustion Products Coalition (TCCPC)	Michael J. Nasi	Trade Association	2
376	Texas Commission on Environmental Quality (TCEQ)	Tangela Niemann on behalf of Mark R. Vickery	State Government	3
377	Texas Department of Transportation, A. Saenz	Jr.	State Government	1
378	Texas Industries, Inc. (TXI) Operations, LP	David Perkins	Beneficial User	2
379	Texas Municipal Power Agency	Jan K. Horbaczewski	Electric Utility Company	2
380	The Concrete Works Sweeney Mining Co., LLC	Cleta Sweeney	Beneficial User	1
381	The SEFA Group	Jimmy Knowless	Beneficial User	1
382	The Society for Protection Coatings (SSPC)	William Shoup	Trade Association	1
383	The Virginia Coal Association, Inc. (VCA)	John T. Heard	Trade Association	1
384	Titan America LLC	James S. Willis	Beneficial User	1
385	Town of Holly, Colorado	Viola Melcher	Local Government	2
386	TransAlta Centralia Generation	Lou Florence	Electric Utility Company	1
387	Trimac Dry Bulk Group, Inc.	Bob Williamson	Beneficial User	1
388	Triple C Concrete Inc.	David Coats	Beneficial User	1
389	Tri-State Generation & Transmission	Barbara A. Walz	Electric Utility Company	2
390	Tucson Electric Power Company	Erik Bakken	Electric Utility Company	1
391	Twin Valleys Public Power District	Karen Workmeister for Bruce A. Lam et. al.	Electric Utility Company	1
392	U.S. Chamber of Commerce	William L. Kovacs	Trade Association	4
393	U.S. House of Representatives	Randy Stewart	Federal Elected Official	2
394	U.S. Minerals	Jason D. Vukas	Beneficial User	2
395	Underground Services Co. d/b/a USC Technologies	Barb DeBusk on behalf of Ritchie Benninghoven	Beneficial User	2
396	Unified Government of Wyandotte County/Kansas City, Kansas	Joseph F. Reardon	Local Government	1
397	United Materials of Great Falls, Inc.	Frances Talbot on behalf of Basil Jacobson	Beneficial User	1
398	United Mine Workers of America (UMWA)	Katy Owen on behalf of Cecil E. Roberts	Union	1
399	United States Gypsum Company (USG)	John Donahue on behalf of Joseph W. Holmes	Beneficial User	2
400	University of Pittsburgh Department of Public Health	Dr. Conrad Daniel Volz	Academia	1
401	USC Technologies, LLC	Sarah Toevs Sullivan	Beneficial User	1
402	Usibelli Coal Mine Incorporated (UCM)	Charles P. Boddy	Other Company	1
403	Utah Physicians for a Healthy Environment	John Veranth	Advocacy Group	1
404	Utility Solid Waste Activities Group (USWAG)	Jim Roewer	Trade Association	10
405	Utility Solid Waste Activities Group (USWAG) et al.	James R. Roewer	Trade Association	9
406	Valley Ready Mix	Brent Baker	Beneficial User	1
407	Vectren Corporation	Angila M. Reinerford	Electric Utility Company	5
408	Verle C. Martz		Beneficial User	1
409	Village of Clinton, Michigan	Merlin Mowery	Local Government	1
410	Virginia Department of Environmental Quality	Jeffery A. Steers	State Government	1
411	Virginia Independent Power Producers, Inc. (VIPP)	August Wallmeyer	Trade Association	1
412	Wake Forest University, Department of Biology	A. Dennis Lemly	Academia	1
413	Walker Parking Consultants	Carl L. Schneeman	Beneficial User	1
414	Washington County, Alabama; Washington County Commission	Charles Singleton	Local Government	1

Exhibit W-1

431 Organizations Which Submitted Comments During the June 21, 2010 to November 19, 2010 Public Comment Period for the June 21, 2010 Proposed CCR Rule

	Organization or Individual	Spokesperson	Organization Type	Count of comments
415	Waste Management (WM)	Susan Briggum	Other Company	1
416	Waste Permits Division, Louisiana Department of Environmental Quality (LDEQ)	Don Caffery	State Government	1
417	Waterkeeper Alliance	Scott Edwards	Advocacy Group	4
418	We Energies	Art Covi	Electric Utility Company	5
419	Weber Sustainability Consulting	Ivan Weber	Beneficial User	3
420	West Virginia Department of Environmental Protection (WVDEP)	Gary Casto on behalf of Randy C. Huffman	State Government	2
421	West Virginia Manufacturers Association (WVMA)	Karen S. Price	Trade Association	2
422	Western Business Roundtable	Holly Propst	Trade Association	1
423	Western Governors' Association	Pam Inmann on behalf of Brian Schweitzer	State Elected Official	1
424	Western Rock Products	Scott Sidlow	Beneficial User	2
425	Wilsonville Concrete Products Commercial Redi Mix (WCP)	Doug Gilmer	Beneficial User	1
426	Wisconsin Department of Natural Resources (WI DNR) and Public Service Commission of Wisconsin (WI PSC)	Matthew Frank (WI DNR) and Eric Callisto (WI PSC)	State Government	3
427	Wisconsin Department of Transportation	Ruben L. Anthony Jr.	State Government	1
428	Wisconsin Public Service	Connie K. Lawniczak	Electric Utility Company	1
429	Wisconsin Ready-Mix Concrete Association (WRMCA)	Mitch Mariotti	Trade Association	2
430	Wyoming Outdoor Council	Bruce Pendery	Advocacy Group	1
431	Xcel Energy	Terry Coss	Electric Utility Company	6

Exhibit W-2:
170 Organizations Which Submitted Comments at EPA's Eight Public Hearings
on the June 21, 2010 Proposed CCR Rule (Held Between August 30 and October 27, 2010)

	Organization	Spokesperson	Organization Type	Count of comments
1	Acme Brick Company	Ed Watson	Beneficial User	2
2	Advanced Wall Technologies (AWT), LLC	Carl Dudding	Beneficial User	1
3	Alpha Natural Resources	Bill Schloemer	Other Company	1
4	American Bituminous Power Partners	Craig Cierra	Electric Utility Facility	1
5	American Coal Ash Association	Mark Bryant	Trade Association	1
6	American Coal Ash Association	Thomas H. Adams	Trade Association	3
7	American Coal Council (ACC)	Janet Gellici	Trade Association	1
8	American Concrete Pipe Association	Matt Childs	Trade Association	1
9	American Electric Power	Dana Sheets	Electric Utility Company	1
10	American Electric Power	Steven Orenchuk	Electric Utility Company	1
11	American Electric Power (AEP)	David Miller	Electric Utility Company	1
12	American Electric Power (AEP)	Richard Hayek	Electric Utility Company	2
13	American Electric Power (AEP)	Steven Orenchuk	Electric Utility Company	1
14	American Forest & Paper Association (AF&PA)	Amy E. Schaffer	Trade Association	2
15	American Road and Transportation Builders Association (ARTBA)	Nick Goldstein	Trade Association	1
16	Arizona Electric Power Cooperative, Inc. (AEPSCO)	Patrick Ledger	Electric Utility Company	2
17	Association of Electric Companies of Texas (AECT)	Walt Baum	Trade Association	3
18	Beneficial Reuse Management	Jeffrey H. Ulrey	Beneficial User	1
19	Black Diamond Granules, Inc.	Bruce Haslerud	Beneficial User	1
20	Blalock Ready Mix	Dennie Underwood	Beneficial User	2
21	Boral Composites	Greg Glander	Beneficial User	1
22	Boral Composites Inc	Thomas D. Zimmerman	Beneficial User	1
23	Boral Composites Inc. (BCI)	Gregory J. Glander	Beneficial User	1
24	Boral Composites, Inc. (BCI)	Brian M. Below	Beneficial User	1
25	Center for Environment, Commerce & Energy (Center)	Norris McDonald	Advocacy Group	1
26	Central Alabama Electric Cooperative	Terry Mitchell	Electric Utility Company	1
27	Charah, Inc. (Charah)	Danny L. Gray	Beneficial User	3
28	Chicago Chapter of Physicians for Social Responsibility	Peter Orris	Advocacy Group	1
29	Citizens Coal Council	John Wathen	Advocacy Group	1
30	City Water, Light & Power, Springfield, IL	Christine Zeman	Electric Utility Company	4
31	Colorado Department of Public Health and Environment	Joe Schieffelin	State Government	2
32	Colorado Interfaith Power & Light	Vicente Roldan	Community/Religious/Social Organization	1
33	Colorado Interfaith Power and Light	Betty Goebel	Community/Religious/Social Organization	2
34	Colorado Interfaith Power and Light	Joy Jamison	Community/Religious/Social Organization	2
35	Colorado Ready Mixed Concrete Association	Bernie Cawley	Trade Association	1
36	Commerce Lexington	Tyler Campbell	Trade Association	1
37	Congress of the United States, House of Representatives	Tim Holden, et al. [122 signatures]	Federal Elected Official	3
38	Congress of the United States, House of Representatives	Tim Murphy	Federal Elected Official	3
39	CPS Energy	Mike Mallone	Electric Utility Company	2
40	Dixie Electric Cooperative	Gary Harrison	Electric Utility Company	3
41	Duke Energy Indiana	Bryan Walsh	Electric Utility Company	2
42	Dynegy Inc.	Linda Whelan	Electric Utility Company	2
43	E.ON U.S. LLC	John Voyles	Electric Utility Company	1
44	E.ON U.S. LLC	Michael Winkler	Electric Utility Company	1
45	Earthjustice		Advocacy Group	1
46	Earthjustice	Emily Greenlee	Advocacy Group	2
47	Ebensburg Power Company	Gary Anderson	Electric Utility Company	4
48	Eco-Justice Ministries	Rev. Peter S. Sawtell	Community/Religious/Social Organization	2
49	Ecologic Tech	Jerry Liu	Beneficial User	1
50	Electric Power Generation Association	Douglas L. Biden	Trade Association	3
51	Environmental Integrity Project	Abel Russ	Advocacy Group	1
52	Environmental Integrity Project	Eric Shaffer	Advocacy Group	1
53	Environmental Integrity Project (EIP)	Lisa Widawsky	Advocacy Group	2
54	Environmental Integrity Project (EIP)	Abel Russ	Advocacy Group	2
55	FirstEnergy	Ray Evans	Electric Utility Company	1
56	Flashfill Services LLC	Doug Hernandez	Beneficial User	2
57	Florida Electric Power Coordinating Group	Carl Eldred	Trade Association	1
58	Full Circle Solutions, Inc.	Steve Critchfield	Beneficial User	2
59	Full Circle Solutions, Inc.	Tyler Farrar	Beneficial User	1

Exhibit W-2:
170 Organizations Which Submitted Comments at EPA's Eight Public Hearings
on the June 21, 2010 Proposed CCR Rule (Held Between August 30 and October 27, 2010)

	Organization	Spokesperson	Organization Type	Count of comments
60	Gibco, Inc.	Bruce Kazich	Beneficial User	2
61	Gilberton Power Company	John K. Hart	Electric Utility Facility	1
62	Great River Energy (GRE)	John Weeda	Electric Utility Company	3
63	Great River Energy (GRE)	Richard Lancaster	Electric Utility Company	4
64	Greater Pittsburgh Chamber of Commerce	Jeff Rossi	Trade Association	1
65	Headwaters Resources	Bill Gehrmann	Beneficial User	2
66	Headwaters Resources (spoke as employee)	David Lawrence	Private Citizen	1
67	Headwaters Resources, Inc. (spoke as employee)	Doug Anderson	Private Citizen	4
68	Headwaters Resources, Inc. (spoke as employee)	John Van Ham	Private Citizen	1
69	Hoosier Energy Rural Electric Cooperative, Inc.	Michalene Reilly	Electric Utility Company	3
70	Illinois Energy Association	James Monk	Trade Association	4
71	Illinois Environmental Regulatory Group (IERG)		Trade Association	1
72	Indiana Energy Association	Stan Pinegar	Trade Association	2
73	Indianapolis Power & Light Company	Dwayne Burke	Electric Utility Company	2
74	International Brotherhood of Electrical Workers	Michael Sowko	Union	1
75	International Brotherhood of Electrical Workers (IBEW)	Michael Welsh	Union	3
76	Iowa Utility Association (IUA)	Mark Douglas	Trade Association	1
77	JEA	Matt McClure	Electric Utility Facility	2
78	JEA	Scott Schultz	Electric Utility Facility	2
79	Kentucky Chamber of Commerce	Chad A. Harpole	Trade Association	4
80	Kentucky Coal Association	Bill Bissett	Trade Association	2
81	Kentucky Ready-Mixed Concrete Association (KRMCA)	R. Finley Messick	Trade Association	3
82	LifeTime Composites, LLC	Mike Thorpe	Beneficial User	2
83	Little Village Environmental Justice Organization	Abigail Singer	Advocacy Group	2
84	Little Village Environmental Justice Organization	Kimberly Wasserman-Nieto	Advocacy Group	1
85	Luminant	Barry Boswell	Electric Utility Company	2
86	Luminant	Julie Prejean	Electric Utility Company	4
87	Luminant	Usha Turner	Electric Utility Company	1
88	Maryland Commission on Environmental Justice and Sustainable Communities	Vernice Miller-Travis	Advocacy Group	2
89	National Association of Manufacturers (NAM)	Alicia Oman	Trade Association	3
90	National Ready Mixed Concrete Association	Terry Jones	Trade Association	1
91	National Ready Mixed Concrete Association (NRMCA)	Dan Huffman	Trade Association	1
92	National Ready Mixed Concrete Association (NRMCA)	Gary Mullings	Trade Association	1
93	National Ready Mixed Concrete Association (NRMCA)	Karthik Obla	Trade Association	1
94	National Ready Mixed Concrete Association (NRMCA)	Kerri Leininger	Trade Association	1
95	National Ready Mixed Concrete Association (NRMCA)	Kevin Walgenbach	Trade Association	1
96	National Ready Mixed Concrete Association (NRMCA)	Richard DeBoer	Trade Association	1
97	National Ready Mixed Concrete Association (NRMCA)	Robert Garbini	Trade Association	2
98	National Rural Electric Cooperative Association (NRECA)	James Stine	Trade Association	2
99	Navajo FlexCrete Building Systems, Inc.	Jonathan S. Robertson	Beneficial User	1
100	Nebraska Ash Company	Tex Leber	Beneficial User	1
101	New Age Fastening Systems	Stephen Swartz	Other Company	1
102	North Carolina Chamber of Commerce	John Goodman	Trade Association	4
103	NRG Energy, Inc. (NRG)	Jeffrey Davis	Electric Utility Company	1
104	NuForm Materials	Brock Marrs	Beneficial User	1
105	Office of the Texas Comptroller of Public Accounts	David Schanbacher	State Government	2
106	Ohio Chamber of Commerce	Jennifer Klein	Trade Association	1
107	Old Dominion Electric Cooperative (ODEC)	David N. Smith	Electric Utility Company	2
108	Pennsylvania Aggregates and Concrete Association	Bruce Cody	Trade Association	1
109	Pennsylvania Coal Association (PCA)	Josie Gaskey	Trade Association	1
110	Pennsylvania Department of Environmental Protection	Michael G. Forbeck	State Government	2
111	Platte River Power Authority	David Ussery	Electric Utility Company	2
112	Platte River Power Authority	Jon Little	Electric Utility Company	3
113	PMI Ash Technologies	Kyle Crake	Beneficial User	1
114	PowerSouth Energy Cooperative	Keith Stephens	Electric Utility Company	2
115	PPL Corporation	Craig Shamory	Electric Utility Company	1
116	PPL Montana, LLC	Steve J. Christian	Electric Utility Company	2
117	Prairie State Generating Company, LLC (PSGC)	Mark A. Shepherd	Electric Utility Company	1
118	Precast Concrete Manufacturers Association of Texas	Chris Lechner	Trade Association	2
119	Presbyterian Church (U.S.A.)	Katie Holmes	Community/Religious/Social Organization	1
120	Protestants for the Common Good (PCG)	Courtney Eccles	Community/Religious/Social Organization	2
121	Richland County Council	Calvin Washington	Local Government	1

Exhibit W-2:
170 Organizations Which Submitted Comments at EPA's Eight Public Hearings
on the June 21, 2010 Proposed CCR Rule (Held Between August 30 and October 27, 2010)

	Organization	Spokesperson	Organization Type	Count of comments
122	San Juan Citizens Alliance	Mike Eisenfel	Advocacy Group	1
123	San Miguel Electric Cooperative	Mike Kezar	Electric Utility Company	1
124	Santee Cooper	Jay Hudson	Electric Utility Company	3
125	Santee Cooper	Tom Edens	Electric Utility Company	1
126	Santee Cooper	Tommy Edens	Electric Utility Company	1
127	SCANA Corporation	Tom Effinger	Electric Utility Company	1
128	Scrubgrass Generating Plant	Peter Rigney	Electric Utility Facility	1
129	Separation Technologies LLC and Essex Cement	Randy Dunlap	Beneficial User	1
130	Sierra Club	Lena Moffett	Advocacy Group	1
131	Sierra Club	Leslie G. Fields	Advocacy Group	4
132	South Carolina Chapter of Sierra Club	Susan Corbett	Advocacy Group	1
133	Southern Alliance for Clean Energy (spoke as employee and citizen)	Katherine Stokes	Private Citizen	1
134	Southern Concrete Materials	Jane Arnold	Beneficial User	3
135	Southern Illinois Power Cooperative	Leonard Hopkins	Electric Utility Company	2
136	Sphere One, Inc.	Mark Bonne	Beneficial User	1
137	Sphere One, Inc.	Ryan Brownhill	Beneficial User	1
138	Sunbury Generation LP	Teresa Copenhaver	Electric Utility Facility	3
139	Sunflower Electric Power Corporation	Paul Reynolds	Electric Utility Company	3
140	Synthetic Materials LLC	Michael W. Beck	Beneficial User	1
141	Tampa Electric Company	Randy Melton	Electric Utility Company	1
142	Tennessee Interfaith Power and Light	Douglas Hunt	Community/Religious/Social Organization	1
143	Tennessee Paper Council (TPC) and American Forest & Paper Association (AF&PA)	Richard Holland	Trade Association	2
144	Texas Coal Ash Utilization Group	Mike Silvertooth	Trade Association	3
145	Texas Concrete Pipe Association	Bob Folser	Trade Association	2
146	Trans Ash, Inc.	Bruce Kazich	Beneficial User	2
147	Tri-State Generation and Transmission Association Inc. (Tri-State)	Chris Gilbreath	Electric Utility Company	3
148	Tufts University	Frank Ackerman	Academia	2
149	University of Kentucky Center for Applied Energy Research	Thomas Robl	Academia	2
150	Vectren Corporation	Angila Retherford	Electric Utility Company	1
151	Vermont Law School	Patrick Parenteau	Academia	2
152	Virginia Manufacturers Association	Joe Croce	Trade Association	1
153	Western Farmers Electric Cooperative (Western Farmers)	Gerald Butcher	Electric Utility Company	5
154	Wisconsin Electric Power Company d/b/a We Energies	Art Covi	Electric Utility Company	2
155	Working People For Fair Energy	Charles Steele, Jr.	Advocacy Group	1
156	No organization identified	Bill Chlebowy	Private Citizen	1
157	No organization identified	Bobby Raia	Private Citizen	2
158	No organization identified	Jessica Miller	Private Citizen	1
159	No organization identified	Jimmy Lambert	Private Citizen	1
160	No organization identified	Joby Adams	Private Citizen	1
161	No organization identified	Jonathan Barker	Private Citizen	2
162	No organization identified	Lev Guter	Private Citizen	1
163	No organization identified	Maria Rosales	Private Citizen	1
164	No organization identified	Matt Durning	Private Citizen	1
165	No organization identified	Matt Durning and N' Jeri Eaton	Private Citizen	1
166	No organization identified	Michael Jackson	Private Citizen	1
167	No organization identified	Rebecca Kolberg	Private Citizen	2
168	No organization identified	Robert Bergman	Private Citizen	1
169	No organization identified	Steve Scarborough	Private Citizen	1
170	No organization identified	William Smith	Private Citizen	1

**Appendix X
to the
Regulatory Impact Analysis (RIA) for
EPA's 2015 Coal Combustion Residuals (CCR) Final Rule**

**Assessment of Potential Future Market Effects
Of the CCR Final Rule**

December 17, 2014

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- EPA Office of Water
- EPA Office of Policy
- EPA Office of Resource Conservation & Recovery

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- ICF International Inc.
- Eastern Research Group
- Industrial Economics Inc.
- Abt Associates Inc.

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Acronyms

AEO	Annual Energy Outlook
BCR	Benefit Cost Ratio
btu	British thermal unit
CAIR	Clean Air Interstate final rule
CBI	confidential business information
CC	combined cycle
CCR	coal combustion residuals
CPI	Consumer Price Index
CPP	Clean Power Plan rule
CSAPR	Cross State Air Pollution final rule
CT	combustion turbine
CWIS	Cooling Water Intake Structures final rule
EGU	electric generating unit
EIA	Energy Information Administration
ELG	Steam Power Electric Power Generator Effluent Limitations Guidelines
EO	executive order
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FGD	flue gas desulfurization technology
FOM	Fixed O&M
FTE	full-time equivalent
GAO	General Accountability Office
GCL	geosynthetic-clay liner
GDP	gross domestic product
GW	gigawatt
GWh	gigawatt hour
IGCC	integrated gasification combined cycle
IGCC-CCS	integrated gasification combined cycle with carbon capture and storage
IPM	Integrated Planning Model
ISO	independent system operators
kWh	kilowatt hour
LF	landfill
MATS	Mercury and Air Toxics final rule
MM tons	million tons
Mmbtu	million btu's
MW	megawatts
MWh	megawatt hour
NAAQS	National Ambient Air Quality Standards final rule

NAICS	North American Industry Classification System
NEEDS	National Electric Energy Data Source
NEMS	National Energy Modeling System
NG	natural gas
O&M	operations and maintenance
O/G	oil/gas steam
OMB	Office of Management and Budget
ORCR	Office of Resource Conservation and Recovery
PC	pulverized coal
PUCs	public utility commissions
PURPA	Public Utilities Regulatory Policy Act
RHR	Regional Haze final rule
RIA	regulatory impact analysis
RTO	regional transmission organization
SI	surface impoundment
Tbtu	trillion btu
TCF	trillion cubic feet
TFP	total factor productivity
VOM	Variable O&M

Executive Summary

ES.1 Overview

In 2015 the Environmental Protection Agency (EPA) is publishing a final rule to regulate the management of coal combustion residuals (CCR) at coal-fired electric utility plants as solid waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The analyses presented in this appendix build upon EPA's 2014 regulatory impact analysis (RIA) for the CCR final rule, by assessing the potential future impacts of the CCR final rule on the U.S. electricity market. This appendix provides analyses which address (a) the impact of the CCR requirements on the electricity generation sector, taking into account the impacts of other existing requirements and current market trends, and (b) the effects of the CCR final rule on employment.

ES.2 Electricity Market Impacts of the CCR Final Rule

Pursuant to Executive Order 13211, *Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use* (May 18, 2001) and associated OMB guidance, this analysis uses the Integrated Planning Model (IPM[®]) v 5.13 to project changes in energy market impacts and electricity prices due to the CCR final rule. Among other regulations included in its baseline, IPM v 5.13 includes the 2012 Mercury and Air Toxics Rule and is custom modified for this analysis to include EPA's August 2014 Clean Water Act Section 316(b) power plant cooling water intake structures (CWIS) final rule.¹ IPM is a comprehensive electricity market optimization model that evaluates electricity market impacts within the context of regional and national electricity markets for the contiguous U.S. IPM estimates various electricity market impacts including capacity, energy price, capacity price, generation, fuel costs, early retirements, and air emissions. This analysis presents IPM's estimated future electricity market impacts for years 2020, 2025, and 2030.

As described in detail below the analysis in this appendix is likely an overestimate of many power sector impacts as the approximation of costs in the CCR IPM runs (which attempt to conservatively account for costs beyond 2054) will tend to overestimate actual costs during the analysis time period.

Exhibit ES-A below summarizes future anticipated changes in projected coal-fired boiler retirements in gigawatts (GW) due to the CCR final rule. **Exhibit ES-B** shows IPM projected changes in future retail electricity prices due to the CCR final rule for the contiguous U.S.

¹ A sensitivity analysis appears in Section B.6 that also includes EPA's June 2014 proposed Clean Power Plan in the IPM baseline.

Exhibit ES-A IPM Projected Future Coal Electricity Generation Retirements due to the CCR Final Rule, 2020-2030 (Gigawatts)				
Year	IPM Baseline	CCR Final Rule	Incremental Effect	Percent Change
2020	49.30	50.11	+0.80	+1.63%
2025	49.56	50.36	+0.80	+1.62%
2030	52.59	53.40	+0.80	+1.53%

Exhibit ES-B IPM Projected Changes in Contiguous U.S. and Regional Retail Electricity Prices due to the CCR Final Rule, 2020-2030 (2013\$ per kilowatt-hour)				
Year	IPM Baseline	CCR Final Rule	Incremental Effect	Percent Change
2020	\$1.083	\$1.084	+\$0.002	+0.18%
2025	\$1.118	\$1.120	+\$0.002	+0.19%
2030	\$1.134	\$1.136	+\$0.002	+0.18%
Totals may not sum due to rounding.				

Exhibit ES-C summarizes the estimated future total changes in electricity generation capacity, by each fuel type individually and in aggregate, for years 2020, 2025, and 2030.

Exhibit ES-C IPM Projected Changes in Future Electricity Generation Capacity due to the CCR Final Rule, 2020-2030 (Gigawatts)			
Electricity Source	IPM Baseline	CCR Final Rule	Percent Change
2020			
Hydro	101.04	101.04	0.00%
Non-Hydro Renewables	92.62	92.63	0.01%
Coal	242.66	241.85	-0.33%
Nuclear	102.92	102.92	0.00%
Natural Gas Combined Cycle	231.89	232.29	0.17%
Combustion Turbine	146.72	146.75	0.02%
Oil/Gas Steam	81.94	81.96	0.02%
Other	4.54	4.54	0.00%
Total	1004.36	1004.01	-0.03%
2025			
Hydro	101.04	101.04	0.00%
Non-Hydro Renewables	103.23	103.26	0.03%
Coal	242.40	241.60	-0.33%
Nuclear	102.92	102.92	0.00%
Natural Gas Combined Cycle	259.42	260.11	0.27%
Combustion Turbine	149.40	149.45	0.03%
Oil/Gas Steam	80.77	80.79	0.03%
Other	4.54	4.54	0.00%
Total	1043.77	1043.75	0.00%
2030			
Hydro	101.04	101.04	0.00%
Non-Hydro Renewables	107.52	107.52	0.00%
Coal	239.37	238.56	-0.34%
Nuclear	100.53	100.53	0.00%
NG Combined Cycle	303.92	304.60	0.22%
Combustion Turbine	157.04	157.12	0.05%
Oil/Gas Steam	80.66	80.68	0.03%
Other	4.54	4.54	0.00%
Total	1094.66	1094.63	0.00%

Exhibits ES-A, ES-B, and ES-C suggest that the incremental future impact of the CCR final rule on coal retirements, electricity prices, and generation capacity is expected to be quite small.

Exhibit ES-D below presents a summary of the IPM projected future power plant air pollutant emission impacts for SO₂, NO_x, CO₂, and mercury in 2020, 2025, and 2030 due to the CCR final rule. **Exhibit ES-E** below provides estimated monetized benefits of the projected pollutant air emissions reductions through the year 2054. **Exhibit ES-F** uses the monetized benefits from **Exhibit ES-E** to recalculate the total benefits, net benefits, and benefit-cost-ratios estimated in the 2014 RIA for the CCR final rule, under 3% and 7% discount rates² and in annualized and present value terms. While the present value estimates are not the appropriate metric for

² IPM uses a 4.77% discount rate in its internal model logic, which is described in **Section B.2**. The discount rates provided here are based on transforming the projected emissions from the IPM model and unitized dollar-per-ton monetization factors, to annualized and present values using 3% and 7% discount rates (for purpose of harmonizing with the same two discount rates applied in EPA-ORCR's 2014 "Regulatory Impact Analysis" for the CCR final rule). This transformation method is described in **Section B.4**.

assessing the impacts to industry or the economy, they are helpful to consistently compare the time streams of estimated benefits and costs. For ease of comparison, **Exhibit ES-F** also presents the original 2014 RIA values in strikethrough.

Exhibit ES-D				
IPM Projected Future Power Plant Air Pollutant Emissions Impacts due to the CCR Final Rule, 2020-2030				
Air Pollutant	IPM Baseline	CCR Final Rule	Incremental Effect	Percent Change
2020				
SO ₂ (million tons)	1.475	1.474	-0.001	-0.07%
NO _x (million tons)	1.556	1.554	-0.002	-0.14%
CO ₂ (million metric tons)	2158.561	2156.801	-1.760	-0.08%
Hg (tons)	8.237	8.226	-0.011	-0.13%
2025				
SO ₂ (million tons)	1.513	1.513	0.000	0.00%
NO _x (million tons)	1.584	1.581	-0.003	-0.19%
CO ₂ (million metric tons)	2227.202	2225.097	-2.104	-0.09%
Hg (tons)	8.729	8.718	-0.011	-0.12%
2030				
SO ₂ (million tons)	1.532	1.531	-0.001	-0.10%
NO _x (million tons)	1.534	1.531	-0.003	-0.21%
CO ₂ (million metric tons)	2251.618	2249.896	-1.722	-0.08%
Hg (tons)	8.735	8.725	-0.009	-0.11%

Exhibit ES-E		
Monetized Benefits of IPM Projected Reductions in Future Power Plant Air Pollutant Emissions due to the CCR Final Rule (millions of 2013\$)		
Discount Rate	Annualized	Present Value
3%	\$88 - \$109	\$2,028 - \$2,511
7%	\$65 - \$74	\$1,493 - \$1,708
Air benefits estimated using IPM emission results through 2054 and Fann et al. (2012) and Interagency Working Group on SCC (2013) using the SCC value at a 3% discount rate. Benefits are scaled down to account for treatment of costs in IPM (see below).		

Exhibit ES-F Illustrative Re-Calculation of CCR RIA Net Benefits & Benefit-Cost Ratios Based on IPM Air Emissions Reduction Benefits Modeling Results (millions of 2013\$)		
	3% Discount Rate	7% Discount Rate
Present values:		
Costs	\$23,200	\$7,260
Benefits	~~\$8,550*~~ \$10,438 - \$10,921	~~\$3,290*~~ \$4,753 - \$4,968
Net Benefits	~~(\$14,700)*~~ (\$12,762 - \$12,279)	~~(\$3,970)*~~ (\$2,507 - \$2,292)
Benefit Cost Ratio (BCR)	~~0.37*~~ 0.45 – 0.47	~~0.45*~~ 0.65 – 0.68
Annualized:		
Costs	\$735	\$509
Benefits	~~\$289*~~ \$372 - \$393	~~\$232*~~ \$295 - \$304
Net Benefits	~~(\$446)*~~ (\$363 - \$342)	~~(\$277)*~~ (\$214 - \$205)
Benefit Cost Ratio (BCR)	~~0.39*~~ 0.51 – 0.53	~~0.46*~~ 0.58 - 0.60
Notes: - Figures rounded to three significant digits (i.e., nearest \$1 million); totals may not sum due to rounding. - Parentheses indicate negative numbers. *Strikethrough values represent benefits as estimated in EPA's 2014 RIA (regulatory impact analysis) for the CCR final rule available from docket nr. EPA-HQ-RCRA-2009-0640 at http://www.regulations.gov		

ES.3 Effect of the CCR Final Rule on Employment

This analysis addresses potential effects on employment. Using qualitative and quantitative methods, this analysis concludes that there could be mixed effects of the CCR final rule on private market employment. The quantitative estimates in this employment analysis for the CCR final rule are not comprehensive; they form only partial estimates for illustrative purposes. This employment evaluation does not reach a quantitative estimate of the overall effects of the CCR final rule on employment or even whether the net effect will be positive or negative. However, given that the expected incremental increase in production costs to the coal-fired electric utility industry is relatively small compared to baseline production costs (without the CCR rule), the magnitudes of all effects combined could be expected to be relatively small as well.

A. Introduction

This appendix summarizes analyses of potential future nationwide electricity and other market impacts of EPA's 2015 CCR final rule. Specifically, this appendix considers potential impacts associated with the following issues:

- **Baseline accounting for existing rules and market trends.** This analysis accounts for the requirements and costs of five other EPA rules as well as existing state requirements that affect coal-fired electric utility plants. This is accomplished by using the Integrated Planning Model (IPM) with its Base Case v5.13 which includes EPA's estimated costs for electric utility plants to comply with four other EPA rules:
 - 2005 RHR: Regional Haze final rule (originally published 1999)
 - 2005 CAIR: Clean Air Interstate final rule
 - 2010 NAAQS: National Ambient Air Quality Standards (NO_x and SO₂)
 - 2012 MATS: Mercury & Air Toxics final rule

In addition, in order to assess the market impacts of the CCR final rule, EPA modified the Base Case v5.13 to include one additional rule that went final between publication of v5.13 and promulgation of the CCR final rule:

- 2014 CWIS: Cooling Water Intake Structures 316(b) final rule

A sensitivity analysis in this appendix includes EPA's proposed New Source Performance Standards for Greenhouse Gas Emissions from Electric Utility Generating Units 111(d) final rule (aka "*Clean Power Plan*" rule proposed in June 2014). This sensitivity analysis is presented in **Section B.6**.

- **Incremental impacts of the CCR final rule.** This incremental analysis represents the effect of the CCR final rule incrementally above the cumulative compliance costs and market impacts of the IPM Base Case v5.13. This incremental analysis includes:
 - **Electricity price impact:** Potential for the CCR final rule to increase future nationwide prices for electricity.
 - **Air pollution reduction:** Potential for the CCR final rule to reduce future air pollution from electric utility plants from induced shifts in generation as a result of market forces.
 - **Electricity sector source impacts:** Potential for the CCR final rule to alter the future demand for coal and other fuels (e.g., natural gas) used by electric utility plants to fuel their boilers to generate electricity.
- **Employment impacts.** Considers the potential for the CCR final rule to affect employment.

B. Integrated Planning Model (IPM) Evaluation of the CCR Final Rule

B.1 Overview of the Integrated Planning Model and IPM Base Case v.5.13

This section provides background on the Integrated Planning Model (IPM) and the most recent version of the IPM Base Case v.5.13.

B.1.1 Integrated Planning Model

In analyzing the impacts of various regulatory actions affecting the electric power sector over the last decade, EPA has used the Integrated Planning Model (IPM[®]), a comprehensive electricity market optimization model that can evaluate such impacts within the context of regional and national electricity markets. Developed and maintained by ICF International, Inc. and used to support public and private sector clients, IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. It provides forecasts of least-cost capacity expansion, electricity dispatch, and emission control strategies for meeting energy demand and environmental, transmission, dispatch, and reliability constraints.

Increases in electricity production costs and potential reductions in electricity output at regulated facilities can have a range of market impacts that extend beyond the effect on regulated facilities. In addition, the impact of compliance requirements on regulated facilities may be seen differently when the analysis considers the impact on those facilities in the context of the broader electricity market instead of looking at the impact on a stand-alone, single-facility basis. Therefore, use of a comprehensive, electricity market modeling system that accounts for interdependence of electric generating units, is important in analyzing regulatory impacts on the electric power industry as a whole.

EPA's use of IPM for this analysis is consistent with the intended use of the model to evaluate the effects of changes on electricity production costs, on electricity generation costs, subject to specified demand and emissions constraints. IPM generates least-cost resource dispatch decisions based on user-specified constraints such as environmental, demand, and other operational constraints. The model can be used to analyze a wide range of electric power market questions at the facility, regional, and national levels. In the past, applications of IPM have included capacity planning, environmental policy analysis and compliance planning, wholesale price forecasting, and asset valuation.

IPM uses a long-term dynamic linear programming framework that simulates the dispatch of generating capacity to achieve a demand-supply equilibrium on a seasonal basis and by region (see **Attachment A** for a comparison of the IPM model regions against AEO NEMS regions and NERC regions, and **Attachment B** for a map of the IPM model regions). The model seeks the optimal solution to an "objective function," which is the summation of all the costs incurred by the electric power sector, i.e., capital costs, fixed and variable operation and maintenance (O&M) costs, and fuel costs, over the entire evaluated time horizon. The objective function is minimized subject to a series of supply and demand constraints. Supply-side constraints include capacity

constraints, availability of generation resources, generating unit minimum operating constraints, transmission constraints, and environmental constraints. Demand-side constraints include reserve margin constraints and minimum system-wide load requirements.³

B.1.2 IPM Base Case v.5.13

To assess plant- and market-level effects of the 2015 CCR final rule, this evaluation used the IPM Base Case v.5.13 as the baseline. EPA initially formulated this Base Case and published it on the EPA IPM website in November 2013. IPM Base Case v.5.13 is a projection of electricity sector activity that takes into account only those Federal and state air emission laws and regulations whose provisions were in effect at the time the base case was finalized in August 2013. To analyze the CCR final rule, EPA adjusted Base Case v5.13 to incorporate one other more recent (August 2014) final EPA rule. Base Case v.5.13 is the most recent IPM iteration at the time of this analysis. The key federal environmental regulations included in the IPM baseline used for the evaluation of the CCR final rule include the following five EPA final rules (2005-2014):

1. 2005 RHR: IPM Base Case v.5.13 reflects the final actions EPA has taken to implement the July 1999 “*Regional Haze*” final rule, which was amended in June 2005. This regulation requires states to submit revised State Implementation Plans (SIPs) that include (1) goals for improving visibility in Class I areas on the 20% worst days and allowing no degradation on the 20% best days and (2) assessments and plans for achieving Best Available Retrofit Technology (BART) emission targets for sources placed in operation between 1962 and 1977. Since 2010, EPA has approved SIPs or, in a very few cases, put in place regional haze Federal Implementation Plans for several states. The BART limits approved in these plans (as of August 29, 2013) that will be in place for EGUs are represented in the IPM Base Case v.5.13.
2. 2005 CAIR: IPM Base Case v.5.13 includes the “*Clean Air Interstate Rule*” (CAIR), a Federal regulatory measure for achieving the 1997 National Ambient Air Quality Standards (NAAQS) for ozone (8-hour average of 0.08 ppm) and fine particles (24-hour average of 65 µg/m³ or less and annual average of 15 µg/m³ for particles of diameter 2.5 micrometers or less, i.e., PM 2.5). Originally issued on March 10, 2005, CAIR was remanded back to EPA by the U.S. Court of Appeals for the District of Columbia Circuit in December 2008 and EPA was required to correct legal flaws in the regulations that had been cited in a ruling by the Court in July 2008. CAIR remains in effect until replaced by EPA pursuant to the Court’s ruling. CAIR’s provisions were still in effect when IPM Base Case v.5.13 was released.
3. 2010 NAAQS (NO_x & SO₂): IPM Base Case v.5.13 includes the 2010 “*National Ambient Air Quality Standards*” final rule to the extent that state regulations included in IPM Base Case v.5.13 contain measures to bring non-attainment areas into attainment. A summary of these state regulations can be found in Appendix 3-2 of EPA’s

³ For further background and documentation about EPA’s IPM Base Case v.5.13, see EPA’s Clean Air Markets webpage titled “*EPA’s Power Sector Modeling Platform v.5.13*” available at: <http://www.epa.gov/powersectormodeling/BaseCasev513.html>

documentation for IPM v.5.13⁴. Apart from these state regulations, individual permits issued by states in response to NAAQS are captured (a) to the extent that they are reflected in the NO_x rates reported to EPA under CAIR, Title IV and the NO_x Budget Program which are incorporated in the base case and (b) to the extent that SO₂ permit limits are used in the base case to define the choice of coal sulfur grades that are available to specific power plants.

4. 2012 MATS: IPM Base Case v.5.13 includes the “*Mercury and Air Toxics Rule*” (MATS), which was finalized in February 2012. MATS establishes National Emissions Standards for Hazardous Air Pollutants (NESHAPS) for the “*electric utility steam generating unit*” source category.
5. 2014 CWIS: In addition to the above EPA final regulations included in the IPM Base Case v.5.13, for analysis of the CCR final rule, EPA’s Clean Air Markets Division (CAMD) updated the IPM Base Case specifically for this analysis, by also sequentially including the EPA-estimated industry compliance costs for the August 2014 “*Cooling Water Intake Structures*” (CWIS) 316(b) final rule. The CWIS rule is not included in the official public version of the IPM Base Case v5.13 released by EPA in November 2013.

Not included in the IPM Base Case applied in this analysis are two other recent EPA rules which, if finalized, would also affect, in part or in whole, coal-fired electric utility plants:

6. 2011 CSAPR: EPA’s July 2011 “*Cross State Air Pollution Final Rule*” (CSAPR) is not included in the IPM Base Case because in December 2011 the US Court of Appeals for the DC Circuit issued a ruling to stay the CSAPR pending judicial review. The stay was subsequently lifted, though implementation of CSAPR was delayed. EPA designed the 2011 CSAPR final rule to replace the 2005 CAIR rule which is listed in this Exhibit.
7. 2014 ELG: In June 2013 EPA’s Office of Water proposed the “*Steam Power Electric Power Generator Effluent Limitations Guidelines*” (ELG) rule. EPA is under court-order to finalize this rule by September 30, 2015. This rule will affect many different types of surface impoundments in the electric utility industry, including the same subset of CCR impoundments which the CCR final rule will affect. Consistent with standard practice, EPA will account for the effect of the CCR final rule in its power market analysis for the ELG final rule in order to capture the combined effects.

Thus, the IPM evaluation of the 2015 CCR final rule reported in this document includes EPA final rules in effect as of August 2014, allowing IPM to provide an estimate of the incremental effect on nationwide electricity markets of the CCR final rule, relative to a baseline representing the five other prior EPA final rules listed above.⁵

⁴ Available at: <http://www.epa.gov/powersectormodeling/BaseCasev513.html>.

⁵ As a sensitivity analysis later in this appendix, a second evaluation consists of the IPM baseline just described plus EPA’s upcoming mid-2015 New Source Performance Standards for Greenhouse Gas Emissions from Electric Utility Generating Units 111(d) final rule (aka “*Clean Power Plan*” (CPP) rule proposed in June 2014).

B.2 IPM Analysis Inputs and Outputs

To assess the impact of the 2015 CCR final rule, this analysis compared the policy case projections to the IPM baseline (i.e., pre-policy) case projections of the modeled electricity market behavior. As noted above, the customized IPM baseline applied for purpose of evaluating the CCR final rule includes EPA Base Case v.5.13 (published November 2013) modified to include EPA's August 2014 "*Cooling Water Intake Structures*" 316(b) final rule.

B.2.1 IPM Inputs

To compare the electricity market effects of the CCR final rule to the modified IPM baseline, EPA used the incremental cost output from the 2014 RIA for the CCR final rule as inputs to the IPM model. IPM requires inputs at the boiler level, and apportioned by capital, fixed O&M (FOM), variable O&M (VOM), avoidable, and unavoidable costs. However, the CCR RIA estimated total costs at the management unit level. Thus costs must be "post-processed" into the appropriate categories before being entered into IPM. Estimation methodologies for each of these cost categories are described in the following subsections.

B.2.1.1 Annual Boiler-Level Cost Inputs

IPM requires annual boiler-level incremental costs of the CCR RIA to effectively model the electricity markets impacts of the CCR final rule.

1. The CCR RIA applied several costing methodologies to estimate industry regulatory compliance costs for the 2015 CCR final rule, most of which were generated by a STATA⁶-based computer model that estimates future annual regulatory compliance costs to electric utility plants at the CCR management unit level (i.e., for each CCR landfill and CCR surface impoundment regulated by the CCR final rule). However, the STATA cost estimation model did not calculate CCR final rule recordkeeping costs or regulatory costs for inactive CCR management units that are presented in the RIA. These costs were calculated separately as nationwide aggregates, and cannot directly be apportioned to individual CCR management units or to individual electric utility plants. The recordkeeping and inactive CCR management unit cost components comprise approximately 10.6% of total average annualized costs of the CCR final rule.⁷

The IPM analysis presented in this appendix did not include regulatory recordkeeping costs and costs for inactive units in the IPM modeling, given the complexity and speculation involved in apportioning it to individual CCR management units, and its relatively small portion of future regulatory costs for the CCR final rule. Only outputs from the RIA's STATA model are fed into IPM, and thus underestimates the total costs as estimated in the full RIA for the CCR final rule.⁸

⁶ STATA is the name of a commercial data and statistical analysis software product: <http://www.stata.com>

⁷ See **Exhibit ES-A** of the RIA for the CCR final rule (at a 7% discount rate).

⁸ The underestimate in this approach is necessary for reasons presented in the preceding paragraph. It is worth noting that the majority of this analysis uses as conservative an approach as possible, and often overestimates cost estimates (e.g., see **Section B.2.1.2** and **Section B.2.1.5**).

2. The STATA model estimated costs at the plant level, and not at the boiler level. IPM requires boiler-level cost data, so to adequately apportion costs of the CCR final rule to individual boilers, this analysis applies the following routine:

- a. Separate out plant-level CCR rule costs into those attributable to regulated CCR surface impoundments and those attributable to regulated CCR landfills.

To determine CCR surface impoundment costs:

- b. For each plant, apportion the plant-level CCR rule costs to each type of regulated CCR material generated at that plant (i.e., fly ash, bottom ash, and flue gas desulfurization residues), based on the 2012 EIA-923 data set for wet-disposed tonnages.⁹
- c. Identify which boilers at each plant have wet handling operations for each CCR material, and thus should incur costs under the CCR rule for each waste stream, using data from EPA Office of Water's 2010 mail survey to power plants for the Steam Electric Power Generating Effluent Limit Guidelines (ELG) proposed rule.¹⁰ Only boilers that have wet handling will incur costs.
- d. Apportion costs to each boiler based on the megawatt (MW) generating capacity only to those boilers that have wet handling operations for that specific CCR material. (In other words, plant-level costs are weighted by CCR disposal tonnages, and then the weighted costs are apportioned proportionally to that plant's wet-handling boilers based on the each boiler's generating capacity.)
- e. Sum the values from step c to calculate the total generating unit level "wet handled" costs.

To determine CCR landfill costs:

- f. Allocate plant-level CCR rule costs attributable to CCR landfills to each coal-fired boiler based on megawatt (MW) capacity.

To determine final boiler level costs:

- g. Sum the values from steps e and f to calculate the total boiler level costs to be used in IPM.

3. The surface impoundment methodology described in Step 2 above applies for plants that report wet disposal to EIA. EPA's 2014 CCR RIA identifies 146 plants that dispose of CCRs to surface impoundments through dry disposal only. For the 146 dry disposal plants, this analysis applies the following approach to apportion costs by CCR type:

⁹ U.S. Department of Energy, Energy Information Administration (EIA), "Form EIA-923 January - December Final, Nonutility Energy Balance and Annual Environmental Information Data, 2012," available online at: http://www.eia.gov/cneaf/electricity/page/eia906_920.html

¹⁰ http://water.epa.gov/scitech/wastetech/guide/steam_index.cfm#point6

- a. Where tonnages were provided in EPA Office of Water's 2010 Steam Electric Questionnaire (referenced above), and noted as being sent to a CCR impoundment (and not claimed confidential business information (CBI)), the CCR tonnages are used directly to calculate a percentage for each CCR material.
- b. Where tonnages were provided in the 2010 questionnaire and noted as being sent to a CCR impoundment (but were claimed CBI), the CCR tonnages cannot be used directly to calculate the percentage. Instead, this analysis split the percentage evenly among the CCR materials for which tonnages were provided.
- c. After supplementing this information, there were still some plants that had CCR surface impoundment regulatory costs for which an apportionment had not been calculated. For these plants, this analysis uses the boiler level information from the 2010 questionnaire to identify which plants have any wet handling operations for each type of CCR material. This analysis then used the same approach described in (b) to breakout out the costs to each CCR material (i.e., split the percentage evenly among the CCR materials for which wet handling operations are used at the plant).
- d. For all remaining plants, this analysis assumes that one-third of the costs goes to each type of CCR material (i.e., fly ash, bottom ash, flue gas desulfurization residues).¹¹

B.2.1.2 Analysis Years

IPM uses model run years to represent the full planning horizon being modeled. Mapping each year in the planning horizon into a representative model run year enables IPM to perform multiple year analyses while keeping the model size manageable. Although IPM reports results only for model run years, it takes into account the costs in all years in the planning horizon. EPA Base Case v.5.13 has a planning horizon to year 2054, and seven distinct model run output years: 2016, 2018, 2020, 2025, 2030, 2040, and 2050. Here we report 2020, 2025, and 2030.

While the EPA Base Case v.5.13 final planning year is 2054, EPA's 2014 RIA for the CCR final rule models costs over the 100-year period from 2015-2114. Provided that many regulatory costs for the CCR final rule as estimated in the RIA begin accruing beyond the IPM horizon, this analysis determined it inappropriate to simply input into IPM year-by-year costs from the RIA model, as that would effectively drop costs accrued beyond year 2054 from IPM. Instead, this analysis applied total average annualized costs from the RIA model as input to IPM as a conservative approach that would include the full cost stream of the CCR rule. This full cost stream estimate, however, represents an uncertain approximation of costs over time since technological innovation, learning effects, and other changes in future market conditions may lead to future year compliance costs which are less than the annualized cost of compliance generated through the methodology applied herein. Significant technological and market

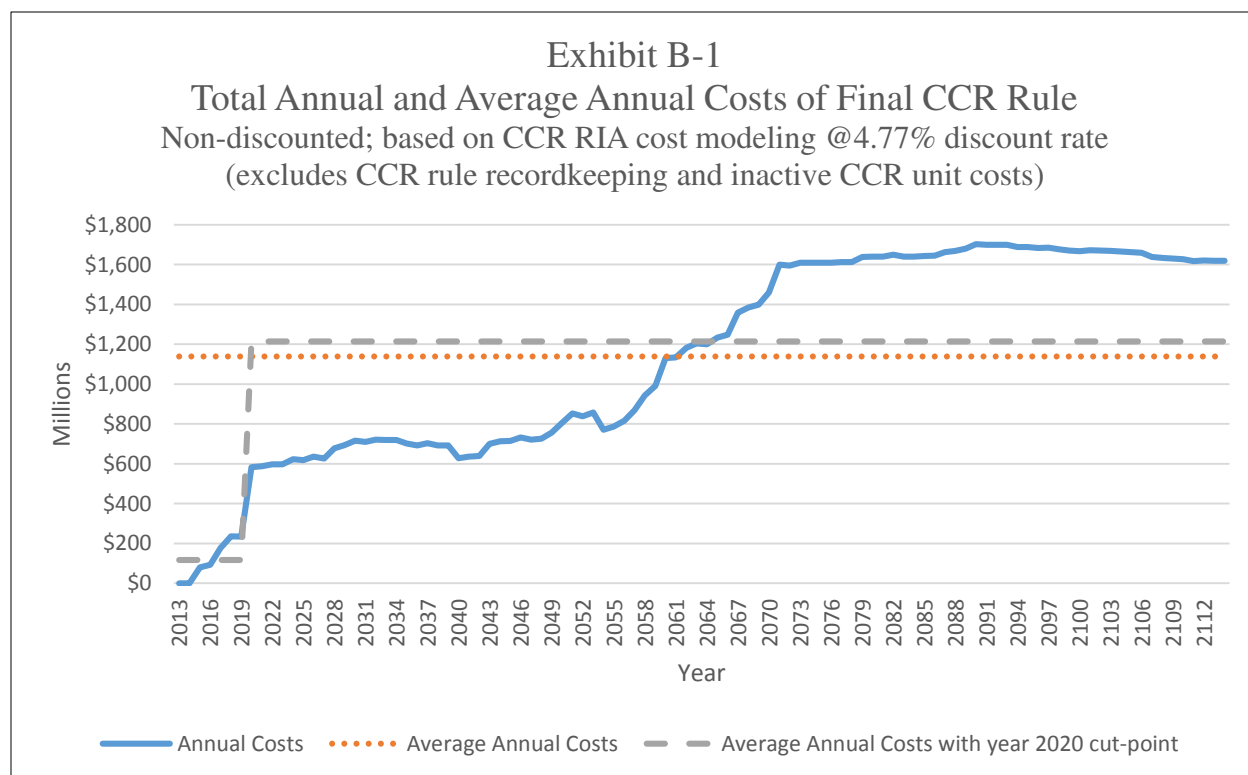
¹¹ This analysis identifies a total of 7 plants modeled as incurring costs in EPA's 2014 RIA for the CCR final rule that have no active boilers of any fuel type in IPM. Additionally, this analysis also identifies a total of 7 plants (separate from those 7 above) that were modeled as incurring costs in the RIA for the CCR final rule that have no active coal-fired boilers in IPM. Because data are not available for these plants in IPM, regulatory compliance costs for the CCR final rule estimated for these 14 plants in the CCR RIA are not represented in the IPM analysis.

condition changes are particularly likely in the context of this analysis, which incorporates compliance cost estimates in the distant future.

As can be seen in **Exhibit B-1** (below) this modified approach thus captures CCR final rule costs incurred after 2054 into the IPM model which are estimated in the RIA to be substantial.

Attachment J shows percentage breakouts of present value costs (and present value benefits, although not used for the IPM exercise) into two time segments according to the 40-year segment 2015-2054 within the IPM timeline, and the 60-year remainder segment 2055-2114 beyond the IPM timeline. At the IPM's 4.77% discount rate, 31% of RIA costs are beyond 2054. (**Attachment J** also presents a breakout of cost and benefit percentages for the RIA 100-year timeline into two 50-year segments.)

One drawback of applying average annualized costs is that it eliminates the yearly fluctuations in costs and replaces it with a constant cost stream. According to the RIA model for the CCR final rule, costs increase substantially in year 2020 as management units begin to detect groundwater contamination. Providing average annualized costs from 2015 to 2114 would ignore this spike in costs. To account for the cost increase in year 2020, this analysis averages annualized costs from 2015 to 2019 and from 2020 to 2114, and then inputs these two sets of average annualized costs into IPM. **Exhibit B-1** presents a visual representation of this average annualized method aggregated across all 478 coal-fired power plants. However, as discussed above, technological innovation, learning effects, and other changes may lead to future year costs for compliance that are less than the nearer-term costs reflected in the average annualized costs applied in this analysis. The uncertainties about technology and market conditions are particularly acute in an analysis attempting to project compliance costs so far into the future.



B.2.1.3 Capital and O&M Cost Components

IPM requires cost inputs to be identified as capital, fixed O&M (FOM), and variable O&M (VOM) cost components. As mentioned above, the CCR RIA did not generate cost breakouts in this way, thus this analysis post-processes the RIA cost output to estimate the capital, FOM, and VOM components. The remainder of this subsection describes the methodology for apportioning costs into these cost components.

This analysis first estimates the capital and O&M component for each of the 12 CCR pollution control cost items identified in the RIA for the CCR final rule. These percentages are applied to the aggregate incremental costs of each CCR pollution control, which are then summed to estimate the total capital and O&M breakdown for all CCR pollution controls. Capital costs are estimated to be 96% and O&M costs 4% of total incremental pollution control costs. All costs, percentage estimates, and rationale are presented in **Attachment C** to this appendix.

This analysis then further breaks down the 4% O&M breakout into FOM and VOM cost components, which are identified as follows:

- **Variable Operation and Maintenance (VOM)** – Non-fuel O&M costs that vary with the level of generation, e.g., cost of consumables, including water, lubricants, and electricity.
- **Fixed Operation and Maintenance (FOM)** – O&M costs that do not vary with the level of generation, e.g., labor costs and capital expenditures for maintenance.

The US Energy Information Administration's (EIA) "*Capital Cost for Electricity Plants*," estimates overnight capital cost, FOM, and VOM for 26 model power plants, seven of which are coal-fired electricity plants.¹² Averaging costs across these seven coal-fired plants indicates 11% of the sample's coal-fired electricity plants' O&M costs are FOM and 89% are VOM. Data and calculations are illustrated in **Attachment D** to this appendix.¹³

¹² US Energy Information Administration, "Capital Cost for Electricity Plants: Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants," April 12, 2013, <http://eia.gov/forecasts/capitalcost/>

¹³ **Attachment D** incorrectly estimated the percentage split between FOM and VOM, as it did not convert them to common units in its calculation. The correct FOM/VOM mix is 47%/53%, instead of the 89%/11% presented above. While the Agency recognizes this issue and will correct it when the final CCR rule is incorporated into the IPM baseline for future regulatory analysis, the 89%/11% split used in this analysis likely has a small effect on the IPM output for the following reasons:

- Changing the ratio of FOM to VOM does not increase or decrease total O&M costs, nor does it affect the split between capital costs and O&M costs.
- This analysis estimates that O&M costs comprise 4% of the incremental costs of the rule. According to the IPM output, the total incremental costs of the rule are less than 1% of total costs in the electricity generation sector. Thus the error affects the distribution of costs within only 4% of less than 1% of total costs in the electricity generation sector.
- Anecdotally, switching weight from FOM to VOM could reduce the retirement pressure that plants currently face in the IPM modeling of the CCR final rule, and give slightly more flexibility to plant operations. Such an effect may result in reduced retirements, meaning a smaller effect on electricity

Applying the above methodology, the yearly average annualized costs from the CCR RIA are multiplied by the following scaling factors to apportion them into capital, FOM, and VOM costs:

- Capital cost = Average annual cost $\times$ 96%
- Fixed O&M (FOM) = Average annual cost $\times$ 4% $\times$ 89%
- Variable O&M (VOM) = Average annual cost $\times$ 4% $\times$ 11%

B.2.1.4 Avoidable and Unavoidable Costs

Under the CCR final rule, certain CCR pollution control regulatory compliance costs, such as those associated with closure and capping of CCR landfills and surface impoundments, are required in the future whether the electric utility plant ceases burning coal or if it continues to burn coal for electricity generation. Such costs are unavoidable, meaning that the plant's decision to operate or close coal-fired boilers does not have an effect on whether the CCR final rule regulatory cost is incurred. The IPM model requires specification of which costs are avoidable or unavoidable, as it has a direct effect on an individual plant's objective to minimize operating and regulatory compliance costs within the IPM model.

Similar to the method described in the previous section of this appendix, this analysis categorically assigns each of the 12 CCR pollution controls as "*avoidable*" or "*unavoidable*," and the costs of each category are summed. Under this method, 88% of costs are avoidable, and 12% are unavoidable. A detailed breakdown of calculations, costs, and rationale is presented in **Attachment E** to this appendix.

Applying the above calculations, the yearly average annualized costs are multiplied by the following scaling factors to apportion them into avoidable and unavoidable costs:

- Avoidable cost = Average annual cost $\times$ 88%
- Unavoidable cost = Average annual cost $\times$ 12%

B.2.1.5 Discounting

IPM Base Case v.5.13 applies a discount rate of 4.77% to its cost inputs.¹⁴ For consistency with IPM, this analysis re-ran the RIA regulatory compliance cost estimation model using a 4.77% discount rate so that future electric utility plant decisions under the CCR final rule are simulated in accordance with the discount rate applied in IPM. The results are applied as cost inputs for the IPM analysis.

While internally the CCR RIA's STATA model used a 4.77% discount rate to model plant decisions, the raw cost output of the STATA model remains undiscounted (as displayed in **Exhibit B-1** above). In other words, the CCR RIA's STATA model chooses each plant's lowest-

markets than currently modeled. However, any effects compared to the current scenario will likely be particularly small.

¹⁴ For a rationale of IPM's 4.77% discount rate, see Chapter 8.2 of EPA's Documentation for v.5.13, available at: <http://www.epa.gov/powersectormodeling/BaseCasev513.html>

cost regulatory compliance path of action over the 100 year modeling horizon under a 4.77% discount rate, and then outputs the 100-year regulatory compliance cost stream of *non-discounted* costs. For the IPM analysis this cost-stream is converted into average annual costs for time periods 2015-2019 and 2020-2114, and inputs these non-discounted annualized costs into IPM for the IPM time frame of 2015 to 2054. This two-tiered IPM cost allocation method resulted in a relatively higher cost input for the IPM analysis, compared to the RIA cost estimates sub-totaled over these two IPM time segments, as follows:

Comparison of CCR RIA & IPM average annual costs 2015-2054 for the CCR final rule
(\$millions @ 4.77% discount rate in 2013\$)

	<u>RIA output (2015-2054)</u>	<u>IPM input (2015-2054)</u>
Average annual cost =	\$512	\$899

IPM then applies its 4.77% discount rate to these two average annualized cost segments. Leaving the STATA output undiscounted and letting IPM apply its discount rate avoids double discounting.

B.2.2 IPM Outputs

The IPM Base Case v.5.13 platform provides outputs for model regions that lie within the continental U.S. The platform does not analyze electric power operations in Alaska and Hawaii because these states' electric power operations are not interconnected with the continental U.S. power grid.¹⁵

IPM generates a series of outputs at different levels of aggregation (model plant, region, and nation). This analysis used a subset of the available IPM outputs to assess the cost and economic impact of the CCR final rule on electricity markets. For each model run (baseline case and policy case) and for the run years indicated above, the following model outputs were generated:

- *Capacity* – Capacity is a measure of the ability to generate electricity. This output measure reflects the summer net dependable capacity of all generating units at the facility. The model differentiates between existing capacity, which is associated with existing generating units and new capacity additions, which are not associated with any specific existing or new generating units.
- *Early Retirements* – IPM models two types of facility closures: closures of nuclear facilities as a result of license expiration and economic closures as a result of negative net present value of future operation. This analysis considers only economic closures as the result of the CCR final rule.
- *Electricity Price* – The average annual wholesale electricity price received by power companies for the sale of electricity.

¹⁵ EPA's 2014 RIA for the CCR final rule identifies a total of 478 potentially affected electric utility plants, 4 of which (0.84%) are located in Alaska or Hawaii. For more information, see **Exhibit 2-D** of the RIA. In the table of projected regional retail electricity prices (**Exhibit B-11**), this analysis exogenously estimates price impacts for Alaska and Hawaii in a footnote (see footnote 16) using the method applied in the 2010 RIA for the CCR proposed rule.

- *Capacity Price* – The premium over energy prices received by power plants operating in peak hours during which system load approaches available capacity; capacity price is part of the total wholesale electricity price. The capacity price is the premium required to stimulate new market entrants to construct additional capacity, cover costs, and earn a return on their investment. This price manifests as short term price spikes during peak hours and, in long-run equilibrium, need be only as large as is required to justify investment in new capacity.
- *Electricity Generation* – The amount of electricity produced by each generating unit that is available for dispatch to the transmission grid (“net generation”). IPM provides summer, winter, and total annual generation.
- *Electricity Fuel Costs* – The cost of fuel consumed in the generation of electricity. IPM provides summer, winter, and total annual fuel costs.
- *Air Pollutant Emissions* – IPM models carbon dioxide (CO₂), nitrogen oxide (NO_x), sulfur dioxide (SO₂), and mercury (Hg) emissions resulting from electricity generation.

Comparison of these outputs for the baseline and policy cases provides insight into the effect of the final rule on regulated facilities and broader electricity markets.

B.3 IPM Evaluation Results for the CCR Final Rule

Throughout this section, this analysis uses the following terms to define the various regulatory policy scenarios and incremental measurements:

- *IPM Baseline*: The IPM v.5.13 Base Case modified for this analysis by including EPA’s August 2014 CWIS final rule, as described in **Section B.1.2**
- *CCR Final Rule*: The *Baseline* IPM run plus the 2015 CCR final rule.
- *Incremental Effect*: The resulting effect of the CCR final rule (i.e., *Baseline* subtracted from *Final Rule*)

This analysis reports IPM results for years 2020, 2025, and 2030.

B.3.1 IPM Projected Power Plant Air Pollutant Emissions

Under the CCR final rule, IPM projects annual CO₂ reductions of 1.76 million metric tons below baseline projections in year 2020. IPM projects a 1,000 ton reduction of SO₂, a 2,000 ton reduction of NO_x, a 2 million metric ton reduction in CO₂ and a 22 lb reduction in mercury in year 2020. The projected emissions reductions presented in **Exhibit B-2** demonstrate similar trends in later years.

Exhibit B-2				
IPM Projected Power Plant Pollutant Air Emissions Impacts, 2020-2030				
Air Pollutant	IPM Baseline	CCR Final Rule	Incremental Effect	Percent Change
2020				
SO ₂ (million tons)	1.475	1.474	-0.001	-0.07%
NO _x (million tons)	1.556	1.554	-0.002	-0.14%
CO ₂ (million metric tons)	2158.561	2156.801	-1.760	-0.08%
Hg (tons)	8.237	8.226	-0.011	-0.13%
2025				
SO ₂ (million tons)	1.513	1.513	0.000	0.00%
NO _x (million tons)	1.584	1.581	-0.003	-0.19%
CO ₂ (million metric tons)	2227.202	2225.097	-2.104	-0.09%
Hg (tons)	8.729	8.718	-0.011	-0.12%
2030				
SO ₂ (million tons)	1.532	1.531	-0.001	-0.10%
NO _x (million tons)	1.534	1.531	-0.003	-0.21%
CO ₂ (million metric tons)	2251.618	2249.896	-1.722	-0.08%
Hg (tons)	8.735	8.725	-0.009	-0.11%

As noted above, annualized costs entered into IPM are slightly higher than the costs for those years reported in the RIA in order to conservatively account for costs in later years. As a result, IPM may tend to slightly overestimate reductions in emissions.

B.3.2 Projected Electricity Generation Fuel Mix

Exhibit B-3 shows the electricity generation fuel mix in the IPM baseline and under the CCR final rule. Over years 2020-2030, total generation is not affected. The mix of generation, however, does change. There are reductions in coal-fired generation, which declines between 0.13% and 0.18%, and increases in natural gas combined cycle generation, which increases between 0.17% and 0.25%. Combustion turbine generation increases by 2% in 2020 and 0.69% in 2025 compared to baseline, but then decreases 0.69% in 2030. Other generation categories have relatively smaller impacts. The small shift away from coal toward natural gas depicted in the results can be explained by the increased marginal cost of coal-fired electricity generation due to the CCR final rule.

Exhibit B-3 Electricity Generation Fuel Mix, 2020-2030 (Thousand Gigawatt Hours)			
Electricity Fuel Source	IPM Baseline	CCR Final Rule	Percent Change
2020			
Hydro	280.09	280.10	0.00%
Non-Hydro Renewables	299.30	299.29	0.00%
Coal	1661.21	1658.71	-0.15%
Nuclear	815.78	815.78	0.00%
NG Combined Cycle	1092.46	1094.55	0.19%
Combustion Turbine	19.03	19.41	2.00%
Oil/Gas Steam	52.05	52.06	0.01%
Other	25.81	25.81	-0.02%
Total	4227.56	4227.59	0.00%
2025			
Hydro	280.26	280.20	-0.02%
Non-Hydro Renewables	335.16	335.15	0.00%
Coal	1696.50	1693.41	-0.18%
Nuclear	816.60	816.60	0.00%
NG Combined Cycle	1205.35	1208.33	0.25%
Combustion Turbine	26.67	26.86	0.69%
Oil/Gas Steam	36.90	36.88	-0.07%
Other	25.36	25.36	0.00%
Total	4403.65	4403.74	0.00%
2030			
Hydro	280.08	280.20	0.04%
Non-Hydro Renewables	350.24	350.24	0.00%
Coal	1662.80	1660.60	-0.13%
Nuclear	797.31	797.31	0.00%
NG Combined Cycle	1415.12	1417.53	0.17%
Combustion Turbine	22.77	22.61	-0.69%
Oil/Gas Steam	22.86	22.87	0.03%
Other	26.94	26.94	0.00%
Total	4557.29	4557.48	0.00%
Note: Columns do not sum due to overlap between some generation categories; however, column totals accurately represents total generation.			

B.3.3 IPM Projected Incremental Coal-Fired Boiler Retirements

Relative to the baseline, about 0.8 gigawatts (GW) of coal-fired electricity generation capacity is projected to be uneconomic to maintain throughout the years 2020 to 2030 under the CCR final rule. The IPM results do not indicate that the CCR final rule will result in retirements of any other electricity fuel source. The projected incremental retirements are reported in **Exhibit B-4**.

Exhibit B-4				
IPM Projected Electricity Generation Retirements, 2020-2030 (Gigawatts)				
Type of Retirements	IPM Baseline	CCR Final Rule	Incremental Effect	Percent Change
2020				
CC Retirements	2.48	2.48	0.00	0.00%
Coal Retirements	49.30	50.11	0.80	1.63%
CT Retirements	0.27	0.27	0.00	0.00%
Nuclear Retirements	1.51	1.51	0.00	0.00%
O/G Retirements	11.78	11.77	-0.02	-0.13%
IGCC Retirements	0.05	0.05	0.00	0.00%
Non-Fossil Retirements	0.00	0.00	0.00	0.00%
Grand Total	65.39	66.18	0.79	1.21%
2025				
CC Retirements	2.48	2.48	0.00	0.00%
Coal Retirements	49.56	50.36	0.80	1.62%
CT Retirements	0.27	0.27	0.00	0.00%
Nuclear Retirements	1.51	1.51	0.00	0.00%
O/G Retirements	12.96	12.94	-0.02	-0.16%
IGCC Retirements	0.05	0.05	0.00	0.00%
Non-Fossil Retirements	0.00	0.00	0.00	0.00%
Grand Total	66.82	67.60	0.78	1.17%
2030				
CC Retirements	2.48	2.48	0.00	0.00%
Coal Retirements	52.59	53.40	0.80	1.53%
CT Retirements	0.27	0.27	0.00	0.00%
Nuclear Retirements	3.90	3.90	0.00	0.00%
O/G Retirements	13.07	13.05	-0.02	-0.16%
IGCC Retirements	0.05	0.05	0.00	0.00%
Non-Fossil Retirements	0.00	0.00	0.00	0.00%
Grand Total	72.36	73.14	0.78	1.08%

As noted above, annualized costs entered into IPM are slightly higher than the costs for those years reported in the RIA in order to conservatively account for costs in later years. As a result of this treatment, IPM may tend to slightly overestimate retirements occurring as a result of the CCR final rule. Because even these conservative impacts show very modest retirements (less than 1GW), which are balanced by additions of new generation (see Exhibit B-6), EPA concludes that the rule will not raise significant concerns over regional resource adequacy or raise the potential for interregional grid problems. EPA believes any remaining local issues can be managed through standard reliability planning processes.

B.3.4 IPM Projected Electricity Generation Capacity

Compared to baseline, total generation capacity falls by 0.03% in 2020, but resumes a zero net change in years 2025 and 2030. Coal's generation capacity decreases by approximately 0.33% in all three analysis years, while natural gas combined cycle increases between 0.17% and 0.27% due to small shifts in the marginal cost of natural gas power generation compared to coal-fired generation under the final rule. Results are shown in **Exhibit B-5**.

Exhibit B-5			
IPM Projected Electricity Generation Capacity by 2020-2030			
(Gigawatts)			
Electricity Fuel Source	IPM Baseline	CCR Final Rule	Percent Change
2020			
Hydro	101.04	101.04	0.00%
Non-Hydro Renewables	92.62	92.63	0.01%
Coal	242.66	241.85	-0.33%
Nuclear	102.92	102.92	0.00%
Natural Gas Combined Cycle	231.89	232.29	0.17%
Combustion Turbine	146.72	146.75	0.02%
Oil/Gas Steam	81.94	81.96	0.02%
Other	4.54	4.54	0.00%
Total	1004.36	1004.01	-0.03%
2025			
Hydro	101.04	101.04	0.00%
Non-Hydro Renewables	103.23	103.26	0.03%
Coal	242.40	241.60	-0.33%
Nuclear	102.92	102.92	0.00%
Natural Gas Combined Cycle	259.42	260.11	0.27%
Combustion Turbine	149.40	149.45	0.03%
Oil/Gas Steam	80.77	80.79	0.03%
Other	4.54	4.54	0.00%
Total	1043.77	1043.75	0.00%
2030			
Hydro	101.04	101.04	0.00%
Non-Hydro Renewables	107.52	107.52	0.00%
Coal	239.37	238.56	-0.34%
Nuclear	100.53	100.53	0.00%
Natural Gas Combined Cycle	303.92	304.60	0.22%
Combustion Turbine	157.04	157.12	0.05%
Oil/Gas Steam	80.66	80.68	0.03%
Other	4.54	4.54	0.00%
Total	1094.66	1094.63	0.00%

B.3.5 IPM Projected Electricity Generation Capacity Additions

Compared to baseline, IPM projects additional natural gas capacity to increase by 2.83% in 2020, 1.61% in 2025, and 0.77% in 2030. As noted above, the increases in natural gas are largely due to its lower marginal cost than coal under the CCR final rule. While there are increases in non-hydro renewable capacity additions, the magnitudes are particularly small compared to baseline. Results are shown below in **Exhibit B-6**.

Exhibit B-6			
IPM Projected Future Electricity Generation Capacity Additions (Cumulative Gigawatts)			
Electricity Fuel Source	2020	2025	2030
Natural Gas			
IPM Baseline	15.27	45.49	97.63
CCR Final Rule	15.70	46.23	98.38
Percent Change	2.83%	1.61%	0.77%
Non-hydro Renewable			
IPM Baseline	17.86	28.46	32.76
CCR Final Rule	17.87	28.50	32.76
Percent Change	0.04%	0.12%	0.00%
Total			
IPM Baseline	33.50	74.33	130.76
CCR Final Rule	33.94	75.09	131.51
Percent Change	1.31%	1.03%	0.57%

B.3.6 IPM Projected Coal Production and Gas Use for the Electric Power Sector

As shown below in **Exhibit B-7**, IPM forecasts that coal production will decline 0.92% in Appalachia in 2020, 0.61% in 2025, and 0.3% in 2030 under the CCR final rule. There is a slight increase of coal production in the West of 0.02% in 2020, and then decreases by 0.12% in 2025 and 0.15% in 2030. No other regions experience any change in coal production. Across all three years, total coal production declines by less than 0.2%.

Exhibit B-7			
IPM Projected Coal Production for the Electric Power Sector			
2020-2030 (Million Tons Coal)			
Coal Supply Region	IPM Baseline	CCR Final Rule	Percent Change
2020			
Appalachia	139.2	137.9	-0.92%
Imports	0.0	0.0	0.00%
Interior	248.7	248.7	0.00%
Waste Coal	9.2	9.2	0.00%
West	444.5	444.6	0.02%
Total	841.6	840.4	-0.14%
2025			
Appalachia	132.5	131.7	-0.61%
Imports	3.6	3.6	0.00%
Interior	260.2	260.2	0.00%
Waste Coal	9.2	9.2	0.00%
West	454.3	453.8	-0.12%
Total	859.9	858.5	-0.16%
2030			
Appalachia	132.5	131.7	-0.30%
Imports	3.6	3.6	0.00%
Interior	260.2	260.2	0.00%
Waste Coal	9.2	9.2	0.00%
West	454.3	453.8	-0.15%
Total	859.9	858.5	-0.12%

Under the CCR final rule, IPM projects that power sector gas use will increase by 0.2% in years 2020 and 2025, and by 0.1% in year 2030. Results are shown in **Exhibit B-8**.

Exhibit B-8			
IPM Projected Electric Power Sector Gas Use			
(Trillion Cubic Feet)			
	2020	2025	2030
IPM Baseline	8.38	8.91	9.93
CCR Final Rule	8.39	8.93	9.94
Percent Change	0.2%	0.2%	0.1%

As noted above, annualized costs entered into IPM are slightly higher than the costs for those years reported in the RIA in order to conservatively account for costs in later years. As a result of this, IPM may tend to slightly overestimate decreases in coal demand and increases in gas demand occurring before 2054 (the final year of the IPM analytic timeline).

B.3.7 IPM Projected Electricity Fuel Price Impacts

The impacts of the CCR final rule on coal and natural gas prices before shipment are shown below in **Exhibit B-9** and **Exhibit B-10**, and are attributable to the policy-induced changes in overall power sector demand for each fuel.

Coal demand decreases slightly over the 2020-2030 time horizon, resulting in a small decrease in the price of coal delivered to the electric power sector. There are even smaller changes in the relative demand and price of gas, which decreases in 2020 and increases in 2025 and 2030. No incremental price movement for either coal or gas due to the final rule is over \$0.01 per million Btu in any time period.

IPM modeling of natural gas prices uses both short- and long-term price signals to balance supply and demand for the fuel across the modeled time horizon. As such, it should be understood that the pattern of IPM natural gas price projections over time is not a forecast of natural gas prices incurred by end-use consumers at any particular point in time. The natural gas market in the U.S. has historically experienced some degree of price volatility from year to year, between seasons within a year, and during short-lived weather events (such as cold snaps leading to short-run spikes in heating demand). These short-term price signals are fundamental for allowing the market to successfully align immediate supply and demand needs. However, end-use consumers are typically shielded from experiencing these rapid fluctuations in natural gas prices by retail rate regulation and by hedging through longer-term fuel supply contracts by the power sector. IPM assumes these longer-term price arrangements take place “outside of the model” and on top of the “real-time” shorter term price variation necessary to align supply and demand. Therefore, the model’s natural gas projections should not be mistaken for traditionally experienced consumer price impacts related to natural gas, but a reflection of expected average price changes over the period of time represented by the modeling horizon.

Exhibit B-9 IPM Projected Average Minemouth and Delivered Coal Prices (2013\$ per Million Btu)						
	Minemouth			Delivered - Electric Power Sector		
	2020	2025	2030	2020	2025	2030
IPM Baseline	\$1.79	\$1.95	\$2.12	\$2.71	\$2.90	\$3.08
CCR Final Rule	\$1.78	\$1.94	\$2.12	\$2.70	\$2.89	\$3.08
Percent Change	-0.42%	-0.27%	-0.22%	-0.24%	-0.19%	-0.15%

Exhibit B-10 IPM Projected Average Henry Hub (spot) and Delivered Natural Gas Prices (2013\$ per Million Btu)						
	Henry Hub (spot)			Delivered - Electric Power Sector		
	2020	2025	2030	2020	2025	2030
IPM Baseline	\$5.16	\$5.89	\$6.21	\$5.56	\$6.33	\$6.62
CCR Final Rule	\$5.16	\$5.90	\$6.22	\$5.55	\$6.34	\$6.62
Percent Change	-0.02%	0.13%	0.05%	-0.03%	0.12%	0.04%
Converted to 2013\$ using CPI.						

B.3.8 IPM Projected Retail Electricity Prices

IPM's analysis projects an increase in the national average (contiguous U.S.) retail electricity price of 0.18% in 2020, 0.19% in 2025, and 0.18% in 2030 under the CCR final rule, compared to the modeled baseline price estimate in those years. Results are broken down by NEMS region in **Exhibit B-11**.^{16,17}

Retail electricity prices embody generation, transmission, distribution, taxes, and utility demand side energy efficiency program costs. IPM projects changes in regional wholesale power prices and capacity payments related to imposition of the represented policy that are combined with EIA regional transmission and distribution costs to calculate changes to regional retail prices. There are many factors influencing the estimated retail electricity price impacts, namely projected changes in the generation mix, fuel prices, and development of new generating capacity. These projected changes vary regionally, and they also vary depending upon retail electricity market structure (e.g., cost-of service vs. competitive).

Exhibit B-11									
IPM Projected Contiguous U.S. and Regional Retail Electricity Prices, 2020-2030									
(2013 cents per Kilowatt hours)									
NEMS Region	IPM Baseline			CCR Final Rule			Percent Change		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
ERCT	102.2	115.9	120.0	102.2	116.0	120.1	0.04%	0.09%	0.05%
FRCC	110.4	112.9	113.3	110.4	113.0	113.3	-0.02%	0.03%	0.02%
MROE	108.0	108.9	108.7	108.1	109.0	108.8	0.06%	0.07%	0.07%
MROW	95.0	95.7	97.2	95.4	96.0	97.6	0.37%	0.36%	0.34%
NEWE	143.2	150.1	156.9	143.2	150.1	157.0	0.01%	-0.01%	0.03%
NYCW	186.2	199.5	206.5	186.2	199.4	206.6	0.00%	-0.03%	0.05%
NYLI	152.3	166.2	174.9	152.2	166.1	175.0	-0.03%	-0.07%	0.09%
NYUP	131.7	140.0	147.3	131.7	140.1	147.4	0.00%	0.08%	0.05%
RFCE	126.8	130.6	128.7	126.8	130.7	128.8	0.02%	0.04%	0.02%
RFCM	110.9	111.1	111.5	111.0	111.2	111.7	0.11%	0.13%	0.12%
RFCW	105.0	113.5	116.1	105.3	113.8	116.4	0.30%	0.23%	0.23%
SRDA	93.2	96.9	98.6	93.2	97.0	98.7	0.04%	0.08%	0.05%
SRGW	96.3	105.0	107.9	96.5	105.2	108.1	0.17%	0.25%	0.24%
SRSE	107.5	107.2	107.6	107.6	107.3	107.7	0.04%	0.09%	0.08%
SRCE	85.4	85.1	84.4	86.1	85.9	85.2	0.82%	0.93%	0.95%
SRVC	110.7	109.7	107.6	110.7	109.8	107.6	0.03%	0.08%	0.08%
SPNO	110.2	107.2	105.5	110.6	107.7	105.9	0.40%	0.39%	0.37%
SPSO	86.6	91.8	94.2	86.7	91.9	94.3	0.13%	0.16%	0.13%
AZNM	108.7	111.4	118.6	109.8	112.4	119.6	1.05%	0.96%	0.78%
CAMX	147.8	144.0	146.3	147.8	144.1	146.3	0.00%	0.04%	0.01%
NWPP	75.5	76.4	77.0	75.8	76.6	77.3	0.41%	0.31%	0.32%
RMPA	92.5	97.2	102.0	92.7	97.6	102.4	0.22%	0.45%	0.34%
Contiguous U.S.	108.3	111.8	113.4	108.4	112.0	113.6	0.18%	0.19%	0.18%

¹⁶ See **Attachment A** to compare the NEMS regions with NERC and IPM regions.

¹⁷ IPM does not provide estimates for Alaska and Hawaii. This analysis exogenously estimated a 0.027% electricity retail price increase for Alaska and a 0.00% electricity retail price increase in Hawaii, using the estimation methodology described on page 204 of EPA's 2010 "Regulatory Impact Analysis For EPA's Proposed RCRA Regulation Of Coal Combustion Residues (CCR) Generated by the Electric Utility Industry."

As noted above, annualized costs entered into IPM are slightly higher than the costs for those years reported in the RIA in order to conservatively account for costs in later years. As a result of this, IPM may tend to slightly overestimate electricity price impacts.

B.3.9 IPM Projected Power Sector Electricity Generating Total Costs

IPM also estimates the incremental costs of the CCR rule as being slightly smaller than the estimates of costs fed into IPM (19%, 8%, and 12% for years 2020, 2025, and 2030 respectively). The cost decrease suggests that adjustments in the power market, including increases in lower cost natural gas generation, will cause the total costs of the CCR rule to be lower than estimated by the engineering model in the RIA which does not capture any of the costs savings that occur when markets adjust by shifting away from coal-fired and towards gas-burning electricity production. However, because the costs fed into IPM do not represent the actual costs incurred in those years, IPM's estimated annual power sector costs cannot be seen as an accurate representation of the annualized cost of the CCR final rule.

B.3.10 Conclusion

In sum, IPM output suggests that the future incremental impacts of the CCR final rule on the market for electricity are expected to be quite small. Impacts on generation mix, capacity, coal-fired boiler retirements, and electricity prices are all very limited. Impacts of reducing air pollution are also modest and are discussed in detail in the next section.

B.4 Monetized Air Pollution Reduction Benefits of the CCR Final Rule based on IPM

This section describes the methodology and results for monetizing air pollution reduction benefits (outlined in **Exhibit B-2**) estimated by IPM for the CCR final rule.

IPM generates electricity plant air pollutant emissions outputs for SO₂, NO_x, CO₂, and mercury for each of the model run years. The model year output does not represent a point estimate for that year, but rather a representation of years surrounding that model year. **Exhibit B-12** reports which IPM modeled years the reported output years represent.

Exhibit B-12	
IPM Model Years (Future Timeline)	
Year Reported In IPM Output	Years Represented by IPM Output
2016	2016 - 2017
2018	2018
2020	2019 - 2022
2025	2023 - 2027
2030	2028 - 2033
2040	2034 - 2045
2050	2046 - 2054

To develop estimated air benefits from the four IPM air pollutant emissions categories, this analysis uses the following approach:

1. The projected emissions reductions for SO₂, NO_x and CO₂ for each reported model year are applied to each of the years that the model year represents (i.e., the SO₂ reductions for 2016 is applied to both years 2016 and 2017, the SO₂ reductions for 2018 is applied to year 2018, and so on for the remainder of years and emission types).
2. Each year estimate for each emission category in Step 1 is multiplied by its respective dollar/ton estimates at both a 3% and 7% discount rate.^{18,19} This analysis does not monetize the reduced mercury emissions reported in the IPM output.
3. The resulting annual monetized estimates are converted to 2013 dollars using CPI, aggregated, and converted to annualized and present-value terms.
4. Because the cost estimates fed into IPM were a simplified, average annualized cost stream rather than annual costs estimated for the CCR rule in the RIA that vary each year (see **Section B.2.1.2**), the annualized and present value benefits in Step 3 are then multiplied by the ratio of the present value of the RIA annual cost estimates for the CCR rule to the present value of the average annualized costs that were submitted to IPM. This

¹⁸ SO₂, NO_x and mercury dollar/ton estimates obtained from EPA's 2013 "Technical Support Document: Estimating the Benefit per Ton of Reducing PM 2.5 Precursors from 17 Sectors," available at:

http://www.epa.gov/airquality/benmap/models/Source_Apportionment_BPT_TSD_1_31_13.pdf.

CO₂ dollar/ton estimates obtained from EPA's 2013 "Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis - Under Executive Order 12866," available at

http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf.

¹⁹ While SO₂, NO_x and mercury each apply the 3% and 7% dollar/ton figures, this analysis uses only the 3% rate for CO₂. This approach is used for internal consistency, and follows from EPA's 2012 "Regulatory Impact Analysis: Final Rulemaking for 2017-2025 Light - Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards." See page ii, available at: <http://www.epa.gov/otaq/climate/documents/420r12016.pdf>.

ratio was calculated for present values under both 3% and 7% discount rates. The result is a monetized estimate of benefits more directly comparable to the costs and benefits presented in the RIA for the CCR final rule.²⁰

The approach described above is subject to important uncertainties. First, generating a year-by-year stream of benefits by assigning target year emission reductions to non-target years is a simplistic method for interpolation between target years that may significantly skew the ensuing net present value benefit estimate. Second, the limitations underlying the estimated stream of future costs (see B.2.1.2) may significantly increase the uncertainties associated with a ratio of NPV benefits to NPV costs. Third, there are significant uncertainties related to the use of benefit per-ton estimates to characterize PM_{2.5}-related benefits which EPA has previously described in detail.²¹ In the present analysis, we use the benefit per-ton estimates to calculate a net present value of the stream of PM_{2.5}-related human health benefits through 2054. This approach further contributes to the uncertainties in the following ways:

1. The NPV of benefits are calculated using a suite of benefit per-ton estimates that are associated with air quality levels, emissions, population, baseline health status and personal income for a fixed year. These parameters are expected to vary over time and so assuming static values may under- or over-estimate the size of the benefits in future years. For analyses including year-by-year benefit and cost streams to calculate NPV, benefit estimates reflecting at least a minimal number of target years for which air quality modeling is conducted to provide anchor points for the multi-year benefit stream would be preferred.
2. The “pulse” approach to quantifying health impacts, in which air pollution-related deaths and illnesses are estimated using air quality changes in a single year, does not fully account for the year-to-year change in mortality rates. That is—the future baseline mortality rate does not fully reflect the change in air pollution-related deaths from prior years. For this reason, analyses characterizing a stream of benefits are generally performed using a life table analysis²²; this approach was not feasible for this RIA due to time and resource limitations. As compared to a life table approach, the pulse approach employed here may under- or over-estimate the NPV of the benefits reported here.

Having noted these limitations, the approach results in the monetized air pollution reduction benefits shown in **Exhibit B-13**, **Exhibit B-14** and **Exhibit B-15**. **Exhibit B-13** presents CO₂-related benefits using the schedule of values for the social cost of carbon, presented in annualized

²⁰ Recall that the IPM input did not include recordkeeping costs or costs for inactive impoundments. The ratio approach described here similarly does not capture these two cost categories. Should IPM have included these costs, it *may* have led to a further shift away from coal and thus less coal emissions in the IPM results than currently modeled. This analysis does not attempt to factor the absence of these two cost categories into the scaled benefit. In that sense, the scaled benefits presented here represent a conservative estimate.

²¹ For example see EPA’s 2013 “Technical Support Document: Estimating the Benefit per Ton of Reducing PM 2.5 Precursors from 17 Sectors,” available at:

http://www.epa.gov/airquality/benmap/models/Source_Apportionment_BPT_TSD_1_31_13.pdf.

²² See, for example, the Institute of Medicine Life Expectancy Tool (IOM-LIFET): <http://www.iom-world.org/research/research-expertise/statistical-services/iomlifet/> and the U.S. EPA Population Simulation Model (PopSim): [http://yosemite.epa.gov/SAB/SABPRODUCT.NSF/347CA16A5EA9CBB78525768D0059CF78/\\$File/IEc+Population+Simulation+Council+12-15-09+Meeting.pdf](http://yosemite.epa.gov/SAB/SABPRODUCT.NSF/347CA16A5EA9CBB78525768D0059CF78/$File/IEc+Population+Simulation+Council+12-15-09+Meeting.pdf)

terms with the scaling factors described above. **Exhibit B-14** presents monetized health benefits of PM_{2.5} precursor reductions, including a range based on the primary estimate for mortality impacts.²³ **Exhibit B-15** presents the total based upon the 3% discount rate SCC unit value.

Exhibit B-13		
CO₂-Related Benefits using Social Cost of Carbon^a		
SCC Discount Rate	Scaled Benefits (3% scaling factor) ^b	Scaled Benefits (7% Scaling Factor) ^c
3%	\$71.0	\$57.32
5%	\$21.3	\$17.17
2.5%	\$105.0	\$84.69
3% (95 UCL)	\$218.9	\$176.62
^a CO ₂ dollar/ton estimates obtained from EPA's 2013 "Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis - Under Executive Order 12866," available at http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf . ^b 3% scaling factor is 0.7531. See Section B.4 for the rationale and approach to develop scaling factors ^c 7% scaling factor is 0.6076. See Section B.4 for the rationale and approach to develop scaling factors		

Exhibit B-14				
Monetized Health Benefits of PM_{2.5} Precursor Reductions				
(Annualized, millions of 2013\$)^a				
	PM _{2.5} Precursor and primary estimate for mortality impacts			
	SO ₂		NO _x	
	Krewski, et al (2009)	Lepeule, et al (2012)	Krewski, et al (2009)	Lepeule, et al (2012)
Discount Rate				
3%	\$4.4	\$9.9	\$12.3	\$27.7
7%	\$2.7	\$6.1	\$4.6	\$10.5
^a SO ₂ , NO _x and mercury dollar/ton estimates obtained from EPA's 2013 "Technical Support Document: Estimating the Benefit per Ton of Reducing PM 2.5 Precursors from 17 Sectors," available at: http://www.epa.gov/airquality/benmap/models/Source Apportionment BPT TSD 1 31 13.pdf . Benefits are scaled downward using 3% and 7% scaling factors, respectively, as in Exhibit B-13				

Exhibit B-15		
Total Monetized Benefits from Social Cost of Carbon (SCC) and PM_{2.5} Precursor Residuals		
(Annualized, millions of 2013\$)		
Discount Rate	Low estimate ^a	High estimate ^b
3%	\$87.7	\$108.6
7%	\$64.6	\$73.9
Values presented in this table sum the values from Exhibit B-13 (using the 3% SCC) and from Exhibit B-14 , for 3% and 7% rates. ^a low estimate represents monetized PM _{2.5} reductions using Krewski, et al (2009) ^b high estimate represents monetized PM _{2.5} reductions using Lepeule et al (2012)		

²³ The range reflects different estimated values for PM_{2.5} mortality impacts. The low estimate is from Krewski, et al., "Extended Follow-Up and Spatial Analysis of the American Cancer Society Study Linking Particulate Air Pollution and Mortality," Health Effects Institute, May 2009. The high estimate is from Lepeule, et al., "Chronic Exposure to Fine Particles and Mortality: An Extended Follow-up of the Harvard Six Cities Study from 1974 to 2009," Environmental Health Perspectives, v. 120 no. 7, July 2012.

B.5 Recalculation of EPA's Regulatory Impact Analysis Benefits, Net Benefits, and Benefit-Cost Ratios Based on IPM Air Emissions Modeling Results

As noted earlier in this analysis, the IPM period of analysis ends in year 2054. However, the RIA for the CCR final rule estimates costs and benefits to year 2114. Because IPM air benefits are not modeled for the full 100 year modeling horizon of the RIA, the methodology described in **Section B.4** underestimates air benefits when compared to the costs and benefits of the RIA. This analysis does not attempt to extrapolate air benefits beyond 2054 which should result in conservative benefit estimates.

These conservative benefit estimates are a significant improvement over the estimates of air quality benefits appearing in the CCR final rule RIA that were scaled from the ELG analysis. However, the cost estimates generated by IPM, as explained in **Section B.2.1**, are themselves derived from average annualized costs (See **Exhibit B-1**) over the entire 100 year time frame of the RIA. As explained in **Section B.3.9**, IPM estimates reduced costs due to adjustments in the electricity marketplace that are not reflected in the RIA. However, because the costs fed into IPM do not represent the costs incurred in the IPM model years, IPM's estimated annual power sector costs are not improvements over the RIA cost estimates. These conclusions are reflected in the following exhibits.

Exhibit B-16 below presents re-calculations of the RIA's total monetized benefits values at both 3% and 7% discount rates, replacing the RIA's prior estimates with the new estimates generated from the IPM air emissions modeling results presented above in this appendix.

Exhibit B-17 below presents re-calculations of net benefits and benefit-cost ratios for 3% and 7% discount rates. In both Exhibits below, the numbers displayed with strikethrough are the prior estimates from the RIA; the re-calculated numbers based on the IPM results of this appendix appear directly below the strikethrough numbers. In **Exhibit B-16** and **Exhibit B-17**, both annualized and present value estimates are presented. While the present value estimates are not the appropriate metric for assessing the impacts to industry or the economy, they are helpful to consistently compare the time streams of estimated benefits and costs.

Exhibit B-16 Re-Calculation of CCR RIA Total Monetized Benefits for the CCR Final Rule (millions of 2013\$ @ alternative discount rates)					
Row	CCR Final Rule Benefit Category	3% discount rate		7% discount rate	
		Annualized	Present value	Annualized	Present value
1	Reduced CCR impoundment releases	\$151	\$4,760	\$138	\$1,960
2	Reduced CCR contamination of groundwater	\$12.8	\$405	\$9.86	\$141
	Closures	~~\$1.60~~	~~\$50.7~~	~~\$1.46~~	~~\$20.9~~
	Bottom liners	~~\$6.56~~	~~\$207~~	~~\$5.06~~	~~\$72.2~~
	Groundwater monitoring	~~\$4.65~~	~~\$147~~	~~\$3.34~~	~~\$47.7~~
3	Increase in future annual CCR beneficial uses	\$117	\$3,130	\$79.0	\$1,120
	CCR rule regulatory compliance “cost offset”	~~\$84.5~~	~~\$2,670~~	~~\$57.1~~	~~\$956~~
	Avoided air pollution & resource consumption	~~\$32.5~~	~~\$459~~	~~\$21.9~~	~~\$164~~
4	Reduced incidence of cancer	\$0.00546	\$0.173	\$0.00273	\$0.0390
5	Avoided IQ losses from mercury	\$0.279	\$8.80	\$0.0246	\$0.351
6	Avoided IQ losses from lead	\$0.186	\$5.87	\$0.0164	\$0.234
7	Reduced need for specialized education stemming from IQ losses	\$0.00273	\$0.0863	\$0.000	\$0.000
8	Non-market water quality benefits	\$2.26	\$71.4	\$1.89	\$27.0
	Improved aquatic and wildlife habitat				
	Enhanced water-based recreation				
	Aesthetic improvements of surface water				
	Increased non-use ecosystem value				
	Reduced risks to aquatic wildlife				
9	Protection of threatened & endangered species in vicinity of CCR management units	\$0.909	\$28.7	\$0.759	\$10.8
10	Improved air quality from power plant emissions	~~\$4.66*~~	~~\$147*~~	~~\$2.04*~~	~~\$29.1*~~
	Reduced air emissions of NO _x , SO ₂ , CO ₂	\$88 – 109	\$2028 - \$2511	\$65-\$74	\$1,493 - \$1,708
11	Reduced groundwater withdrawals by power plants (reduced CCR water sluicing from conversion from wet to dry CCR handling)	\$0.00273	\$0.0863	\$0.00273	\$0.0390
		~~\$289*~~	~~\$8,550*~~	~~\$232*~~	~~\$3,290*~~
	Column Totals =	\$372 - \$393	\$10,438 - \$10,921	\$295-\$304	\$4,753 - \$4,968
Notes: • Figures are rounded to three significant digits; totals may not add due to rounding. • *Strikethrough values represent benefits as estimated in EPA’s December 2014 RIA for the CCR final rule • Range estimates reflect the low and high estimates from Exhibit B-15.					

Exhibit B-17 Re-Calculation of CCR RIA Net Benefits & Benefit-Cost Ratios Based on IPM Air Pollutant Emissions Modeling Results (millions of 2013\$)		
	3% Discount Rate	7% Discount Rate
Present values:		
Costs	\$23,200	\$7,260
Benefits	~~\$8,550*~~ \$10,438 - \$10,921	~~\$3,290*~~ \$4,753 - \$4,968
Net Benefits	~~(\$14,700)*~~ (\$12,762 - \$12,279)	~~(\$3,970)*~~ (\$2,507 - \$2,292)
Benefit Cost Ratio (BCR)	~~0.37*~~ 0.45 – 0.47	~~0.45*~~ 0.65 – 0.68
Annualized:		
Costs	\$735	\$509
Benefits	~~\$289*~~ \$372 - \$393	~~\$232*~~ \$295 - \$304
Net Benefits	~~(\$446)*~~ (\$363 - \$342)	~~(\$277)*~~ (\$214 - \$205)
Benefit Cost Ratio (BCR)	~~0.39*~~ 0.51 – 0.53	~~0.46*~~ 0.58 – 0.60
Notes: - Figures rounded to three significant digits; totals may not sum due to rounding. - Parentheses indicate negative numbers. *Strikethrough values represent benefits as estimated in EPA's December 2014 RIA for the CCR final rule. - Range estimates reflect the low and high estimates from Exhibit B-15.		

B.6 Sensitivity Analysis: Alternative IPM Baseline Scenario

B.6.1 Sensitivity Analysis Overview

As a sensitivity analysis, this section considers the electricity market effects of the CCR final rule using an alternative baseline that includes EPA's 2014 "*Clean Power Plan*" (CPP) proposed rule.²⁴ While EPA expects the CCR rule to be published in the Federal Register in early 2015 (e.g., February or March 2015) prior to the CPP final rule, this sensitivity analysis is included because of the CCP's expected potential future effects on the U.S. electricity market. This alternative baseline therefore includes IPM Base Case v.5.13, EPA's August 2014 CWIS final rule, plus the 2014 proposed Clean Power Plan rule.²⁵ The incremental effect of the CCR final rule is then compared to this alternative IPM baseline.

Throughout this sensitivity analysis section, this analysis uses the following terms to define the various policy scenarios and incremental measurements:

- *Alternative Baseline:* The IPM v.5.13 base case modified for this analysis to also include EPA's August 2014 316(b) CWIS final rule, plus EPA's 2014 proposed Clean Power Plan (CPP).
- *Final Rule:* The *Alternative Baseline* IPM run plus the CCR final rule
- *Incremental Effect:* The resulting effect of the CCR final rule. (i.e., *Alternative Baseline* subtracted from *Final Rule*).

Overall, the electricity market effects of the CCR rule after controlling for the Clean Power Plan rule are mixed when compared to the primary scenario that does not include the Clean Power Plan rule. Fuel consumption for electricity generation, retail electricity prices, and electricity plant pollutant air emissions decrease slightly in some regions and IPM model years, while they increase slightly or remain unchanged in others. The mixed results are due to electricity plants in IPM minimizing costs under a new set of EPA regulatory policy requirements, leading to future plant business decisions that are simulated in IPM as potentially reducing some estimated market effects while increasing others. As with the primary scenario, the percent changes of all results remain particularly small for this sensitivity analysis.

²⁴ For further information on EPA's 2014 Clean Power Plan (CPP) proposed rule, see: <http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule>.

For a discussion of the Clean Power Plan's IPM run, see Chapter 3 of "Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emissions Standards for Modified and Reconstructed Power Plants," available at: <http://www.epa.gov/ttnecas1/regdata/RIAs/111dproposalRIAFinal0602.pdf>.

²⁵ See **Section B.1.2** for further discussion on IPM Base Case v.5.13 and EPA's ELG rule.

B.6.2 Sensitivity Analysis Results

Exhibits B-18 through B-24 below present selected results of the sensitivity analysis described above.

Exhibit B-18 IPM Projected Power Plan Pollutant Air Emissions Impacts, 2020-2030 <i>(Sensitivity Analysis*)</i>				
	Alternative IPM Baseline	CCR Final Rule	Incremental Effect	Percent Change
2020				
SO ₂ (million tons)	1.14	1.14	0.000	0.04%
NO _x (million tons)	1.19	1.19	-0.001	-0.10%
CO ₂ (million metric tons)	1757.39	1754.92	-2.468	-0.14%
Hg (tons)	6.75	6.73	-0.021	-0.31%
2025				
SO ₂ (million tons)	1.09	1.09	0.000	-0.05%
NO _x (million tons)	1.15	1.15	0.000	-0.01%
CO ₂ (million metric tons)	1704.79	1702.90	-1.891	-0.11%
Hg (tons)	6.71	6.69	-0.021	-0.32%
2030				
SO ₂ (million tons)	1.06	1.06	-0.001	-0.06%
NO _x (million tons)	1.11	1.11	-0.001	-0.12%
CO ₂ (million metric tons)	1680.77	1679.11	-1.656	-0.10%
Hg (tons)	6.64	6.62	-0.018	-0.28%
*Note: This sensitivity analysis compares the effect of the CCR final rule to a baseline that includes IPM Base Case v.5.13, EPA's August 2014 CWIS final rule, plus EPA's 2014 proposed Clean Power Plan (CPP).				

Exhibit B-19
Electricity Generation Fuel Mix, 2020-2030
(Thousand Gigawatt hours)
(Sensitivity Analysis*)

Electricity Fuel Source	Alternative Baseline	CCR Final Rule	Percent Change
2020			
Hydro	281.34	281.67	0.12%
Non-Hydro Renewables	322.38	320.31	-0.64%
Coal	1300.19	1296.04	-0.32%
Nuclear	817.82	817.82	0.00%
NG Combined Cycle	1316.93	1323.76	0.52%
Combustion Turbine	32.84	32.62	-0.66%
Oil/Gas Steam	13.74	13.60	-1.03%
Other	26.29	26.29	0.02%
Total	4099.38	4099.70	0.01%
2025			
Hydro	281.55	281.53	-0.01%
Non-Hydro Renewables	345.63	343.50	-0.62%
Coal	1249.09	1245.14	-0.32%
Nuclear	818.64	818.64	0.00%
NG Combined Cycle	1303.58	1309.65	0.47%
Combustion Turbine	37.04	36.69	-0.97%
Oil/Gas Steam	14.78	14.92	0.93%
Other	25.71	25.71	0.00%
Total	4061.87	4061.67	0.00%
2030			
Hydro	280.29	280.43	0.05%
Non-Hydro Renewables	355.77	353.57	-0.62%
Coal	1214.33	1210.68	-0.30%
Nuclear	797.31	797.31	0.00%
NG Combined Cycle	1347.71	1353.89	0.46%
Combustion Turbine	29.97	29.61	-1.20%
Oil/Gas Steam	11.77	12.03	2.19%
Other	27.38	27.38	0.00%
Total	4051.20	4051.64	0.01%

Note: Columns do not sum due to overlap between some electricity generation categories; however, column totals accurately represents total generation.

*This sensitivity analysis compares the effect of the CCR final rule to a baseline that includes IPM Base Case v.5.13, EPA's August 2014 CWIS final rule, and EPA's 2014 proposed Clean Power Plan (CPP).

Exhibit B-20 IPM Projected Electricity Generation Retirements, 2020-2030 (Gigawatts) (Sensitivity Analysis*)				
Type of Retirements	Alternative IPM Baseline	CCR Final Rule	Incremental Effect	Percent Change
2020				
CC Retirements	5.96	5.78	-0.18	-3.00%
Coal Retirements	97.74	99.43	1.68	1.72%
CT Retirements	2.61	2.63	0.02	0.72%
Nuclear Retirements	1.23	1.23	0.00	0.00%
O/G Retirements	28.01	27.76	-0.25	-0.88%
IGCC Retirements	0.14	0.15	0.00	2.99%
Non-Fossil Retirements	0.00	0.00	0.00	0.00%
Grand Total	135.69	136.97	1.28	0.94%
2025				
CC Retirements	6.17	6.00	-0.18	-2.89%
Coal Retirements	99.38	100.79	1.41	1.42%
CT Retirements	2.61	2.63	0.02	0.72%
Nuclear Retirements	1.23	1.23	0.00	0.00%
O/G Retirements	28.59	28.36	-0.23	-0.79%
IGCC Retirements	0.14	0.15	0.00	2.99%
Non-Fossil Retirements	0.00	0.00	0.00	0.00%
Grand Total	138.13	139.15	1.03	0.75%
2030				
CC Retirements	6.17	6.00	-0.18	-2.89%
Coal Retirements	101.97	103.42	1.45	1.43%
CT Retirements	2.61	2.63	0.02	0.72%
Nuclear Retirements	3.90	3.90	0.00	0.00%
O/G Retirements	28.59	28.36	-0.23	-0.79%
IGCC Retirements	0.14	0.15	0.00	2.99%
Non-Fossil Retirements	0.00	0.00	0.00	0.00%
Grand Total	143.38	144.45	1.07	0.75%
Note: *This sensitivity analysis compares the effect of the CCR final rule to a baseline that includes IPM Base Case v.5.13, EPA's August 2014 CWIS final rule, plus EPA's 2014 proposed Clean Power Plan (CPP).				

Exhibit B-21 IPM Projected Coal Production for the Electric Power Sector, 2020-2030 (Million Tons) (Sensitivity Analysis*)			
Coal Supply Region	Alternative IPM Baseline	CCR Final Rule	Percent Change
2020			
Appalachia	91.5	91.2	-0.22%
Imports	0.0	0.0	0.00%
Interior	221.9	219.7	-1.03%
Waste Coal	9.7	9.7	0.00%
West	291.3	290.9	-0.13%
Total	614.4	611.6	-0.47%
2025			
Appalachia	73.5	73.3	-0.30%
Imports	2.0	2.0	0.19%
Interior	222.0	219.0	-1.37%
Waste Coal	9.7	9.7	0.00%
West	284.1	285.0	0.34%
Total	591.3	589.0	-0.39%
2030			
Appalachia	73.5	73.3	0.07%
Imports	2.0	2.0	0.05%
Interior	222.0	219.0	-2.19%
Waste Coal	9.7	9.7	-3.15%
West	284.1	285.0	1.11%
Total	591.3	589.0	-0.34%
Note: *This sensitivity analysis compares the effect of the CCR final rule to a baseline that includes IPM Base Case v.5.13, EPA's August 2014 CWIS final rule, plus EPA's 2014 proposed Clean Power Plan (CPP).			

Exhibit B-22 IPM Projected Average Minemouth and Delivered Coal Prices (2011\$ per million Btu) (Sensitivity Analysis*)						
	Minemouth			Delivered - Electric Power Sector		
	2020	2025	2030	2020	2025	2030
Alternative IPM Baseline	\$1.50	\$1.62	\$1.76	\$2.26	\$2.38	\$2.52
CCR Final Rule	\$1.50	\$1.62	\$1.75	\$2.26	\$2.39	\$2.53
Percent Change	-0.48%	-0.12%	-0.22%	-0.19%	0.10%	0.06%
Note: Converted to 2011\$ using CPI. *This sensitivity analysis compares the effect of the CCR final rule to a baseline that includes IPM Base Case v.5.13, EPA's August 2014 CWIS final rule, plus EPA's 2014 proposed Clean Power Plan (CPP).						

Exhibit B-23 IPM Projected Average Henry Hub (spot) and Delivered Natural Gas Prices (2013\$ per million Btu) (Sensitivity Analysis*)						
	Henry Hub (spot)			Delivered - Electric Power Sector		
	2020	2025	2030	2020	2025	2030
Alternative IPM Baseline	\$5.82	\$5.76	\$6.29	\$6.20	\$6.10	\$6.62
CCR Final Rule	\$5.83	\$5.75	\$6.31	\$6.21	\$6.10	\$6.64
Percent Change	0.17%	-0.06%	0.37%	0.14%	-0.06%	0.23%
Note: Updated to 2013\$ using CPI. *This sensitivity analysis compares the effect of the CCR final rule to a baseline that includes IPM Base Case v.5.13, EPA's August 2014 CWIS final rule, plus EPA's 2014 proposed Clean Power Plan (CPP).						

Exhibit B-24 IPM Projected Contiguous U.S. and Regional Retail Electricity Prices, 2020-2030 (2013 cents/kWh) (Sensitivity Analysis*)									
NEMS Region	Alternative Baseline			CCR Final Rule			Percent Change		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
ERCT	112.3	118.0	124.8	112.7	117.9	125.0	0.35%	-0.13%	0.17%
FRCC	120.0	118.9	119.6	120.1	118.9	119.7	0.05%	-0.02%	0.13%
MROE	114.2	113.6	115.2	114.2	113.7	115.3	0.00%	0.03%	0.07%
MROW	101.8	101.2	101.4	102.0	101.5	101.8	0.26%	0.36%	0.34%
NEWE	159.7	150.1	158.5	159.8	150.0	158.5	0.09%	-0.09%	-0.02%
NYCW	205.1	197.2	208.2	205.2	197.0	208.0	0.05%	-0.08%	-0.07%
NYLI	166.9	158.8	169.1	167.0	158.6	168.9	0.07%	-0.11%	-0.11%
NYUP	145.0	136.4	146.8	145.0	136.3	146.7	0.00%	-0.09%	-0.06%
RFCE	136.6	133.6	134.1	136.6	133.8	134.1	-0.03%	0.16%	0.03%
RFCM	117.6	116.0	116.5	117.7	116.0	116.5	0.09%	0.00%	0.00%
RFCW	111.5	113.5	116.9	111.9	114.4	117.1	0.32%	0.74%	0.24%
SRDA	97.2	100.5	103.0	97.3	100.5	103.1	0.11%	0.02%	0.13%
SRGW	100.8	104.8	106.2	101.0	105.1	106.6	0.25%	0.28%	0.35%
SRSE	111.2	111.2	112.0	111.2	111.3	112.1	0.06%	0.03%	0.11%
SRCE	86.9	87.9	86.8	87.6	88.7	87.7	0.89%	0.93%	1.00%
SRVC	113.2	112.4	110.3	113.3	112.5	110.4	0.08%	0.08%	0.11%
SPNO	111.1	112.2	108.9	111.6	112.7	109.4	0.44%	0.46%	0.42%
SPSO	96.6	100.0	102.7	96.3	99.9	102.7	-0.23%	-0.14%	-0.04%
AZNM	116.8	116.9	121.2	117.7	117.7	122.3	0.81%	0.71%	0.89%
CAMX	157.2	148.2	152.1	157.3	148.2	152.1	0.06%	0.00%	-0.01%
NWPP	80.4	79.9	79.2	80.7	80.2	79.5	0.34%	0.32%	0.29%
RMPA	102.1	103.4	106.8	102.4	103.5	107.0	0.23%	0.09%	0.23%
Contiguous U.S.	115.3	114.8	116.9	115.5	115.0	117.1	0.20%	0.20%	0.19%
Note: Converted to 2013\$ using CPI. *This sensitivity analysis compares the effect of the CCR final rule to a baseline that includes IPM Base Case v.5.13, EPA's August 2014 CWIS final rule, plus EPA's 2014 proposed Clean Power Plan (CPP).									

B.6.3 Sensitivity Analysis: Conclusion

Compared to the primary scenario IPM results of **Section B.3**, the IPM results of the sensitivity analysis are mixed. Some market effects are decreased, while others are increased. For example, the sensitivity analysis estimates further reductions in emissions than the primary scenario. Separately, both the primary scenario and the sensitivity analysis show projected coal retirements of roughly 1.5% compared to baseline across all three analysis years. As a final example, the primary scenario shows the largest decreases in coal production in the Appalachia region, while the sensitivity analysis has the largest decreases in the U.S. interior.

While the directions and magnitudes of the results are mixed, all results of both the primary scenario and the sensitivity analysis are small. Thus, whether or not the CPP rule is included in the IPM baseline, the projected electricity market impacts of the CCR final rule are minimal. These results further support EPA's conclusion that the rule will not raise significant concerns over regional resource adequacy or raise the potential for interregional grid problems. EPA believes any remaining local issues can be managed through standard reliability planning processes.

C. Effects on Employment

C.1 Potential Effect on Private Market Employment

Section 1 of Executive Order 13563 directs federal agencies to consider the effect of regulations on employment and jobs creation (bold face added below):

*“Our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and **job creation.**”²⁶*

This analysis provides a conceptual framework for the potential influence of environmental regulations on industrial employment. It offers rough estimates of possible future employment impacts on the coal-fired electricity generation sector; and mostly qualitative analyses of employment impacts on other related sectors.

C.1.1 Theoretical Framework

C.1.1.1 Background of Environmental Impacts on Environmental Regulations

The employment effects of environmental regulation are difficult to disentangle from other economic changes and business decisions that affect employment, over time and across regions and industries. In light of these difficulties, economic theory provides a constructive framework for approaching these assessments and for better understanding the inherent complexities in such assessments. Neoclassical microeconomic theory describes how profit maximizing firms adjust their use of productive inputs in response to changes in their economic conditions.²⁷ In this framework, labor demand impacts for regulated sectors can be decomposed into output and substitution effects. For the output effect, by affecting the marginal cost of production, regulation affects the profit-maximizing quantity of output. The substitution effect describes how, holding output constant, regulation affects the labor-intensity of production. Because the output and substitution effects may be both positive, both negative or some combination, standard neoclassical theory alone does not point to a definitive net effect of regulation on labor demand at regulated firms.

In the labor economics literature there is an extensive body of peer-reviewed empirical work analyzing various aspects of labor demand, relying on the above theoretical framework.²⁸ This work focuses primarily on the effects of employment policies, e.g. labor taxes, minimum wage, etc.²⁹ In contrast, the peer-reviewed empirical literature specifically estimating employment

²⁶ Source: Executive Order 13563 (January 21, 2011). *Improving Regulation and Regulatory Review. Section 1. General Principles of Regulation*, Federal Register, Vol. 76, Nr. 14, p. 3821.

²⁷ See Layard, P.R.G., and A. A. Walters (1978), *Microeconomic Theory* (McGraw-Hill, Inc.), Chapter 9 (document ID nr. EPA-HQ-OAR-2011-0135 at <http://www.regulations.gov>), a standard microeconomic theory textbook treatment, for a discussion.

²⁸ See Hamermesh (1993), *Labor Demand* (Princeton, NJ: Princeton University Press), Chapter 2, docket nr. EPA-HQOAR-2011-0135 at <http://www.regulations.gov> for a detailed treatment.

²⁹ See Ehrenberg, Ronald G., and Robert S. Smith (2000), *Modern Labor Economics: Theory and Public Policy*

effects of environmental regulations is very limited. Several empirical studies, including Berman and Bui (2001) and Morgenstern et al. (2002) suggest that net employment impacts may be zero or slightly positive but small even in the regulated sector.^{30,31} Other research (Greenstone (2002); Walker (2011)) suggests that more highly regulated counties may generate fewer jobs than less regulated ones.³² However, since these latter studies compare more regulated to less regulated counties, they overstate the net national impact of regulation to the extent that regulation causes plants to locate in one area of the country rather than another. List et al. (2007) find some evidence that this type of geographic relocation may be occurring.³³ Overall, the peer-reviewed literature does not contain evidence that environmental regulation has a large impact on net employment (either negative or positive) in the long run across the whole economy.

Analytic challenges make it very difficult to accurately produce net employment estimates for the whole economy that would appropriately capture the way in which costs, compliance spending, and environmental benefits propagate through the macro-economy. Quantitative estimates are further complicated by the fact that macroeconomic models often have very little sectorial detail and usually assume that the economy is at full employment. In 2014 the EPA is in the process of seeking input from an independent expert panel on modeling economy-wide impacts, including employment effects.³⁴

C.1.1.2 Employment Theory in the Coal-Fired Electricity Industry

When the economy is at full employment, an environmental regulation is unlikely to have much impact on net overall U.S. employment; instead, labor would primarily be shifted from one sector to another. These shifts in employment impose an opportunity cost on society, approximated by the wages of the employees, as regulation diverts workers from other activities in the economy. In this situation, any effects on net employment are likely to be transitory as workers change jobs (e.g., some workers may need to be retrained or require time to search for new jobs, while shortages in some sectors or regions could bid up wages to attract workers).

(Addison Wesley Longman, Inc.), Chapter 4, docket nr. EPA-HQ-OAR-2011-0135 at <http://www.regulations.gov>

³⁰ Berman, E. and L. T. M. Bui (2001). "Environmental Regulation and Labor Demand: Evidence from the South Coast Air Basin." *Journal of Public Economics* 79(2): 265-295, docket nr. EPA-HQ-OAR-2011-0135 at <http://www.regulations.gov>

³¹ Morgenstern, Richard D., William A. Pizer, and Jhih-Shyang Shih. "Jobs Versus the Environment: An Industry-Level Perspective." *Journal of Environmental Economics and Management* 43 (2002): 412-436, docket nr. EPA-HQOAR-2011-0135-0057 at <http://www.regulations.gov>

³² Greenstone, M. (2002). "The Impacts of Environmental Regulations on Industrial Activity: Evidence from the 1970 and 1977 Clean Air Act Amendments and the Census of Manufactures," *Journal of Political Economy* 110(6): 1175-1219, docket nr. EPA-HQ-OAR-2011-0135 at <http://www.regulations.gov>

Walker, Reed. (2011). "Environmental Regulation and Labor Reallocation." *American Economic Review: Papers and Proceedings* 101(3): 442-447, docket nr. EPA-HQ-OAR-2011-0135 at <http://www.regulations.gov>

³³ List, J. A., D. L. Millimet, P. G. Fredriksson, and W. W. McHone (2003). "Effects of Environmental Regulations on Manufacturing Plant Births: Evidence from a Propensity Score Matching Estimator." *The Review of Economics and Statistics* 85(4): 944-952, docket nr. EPA-HQ-OAR-2011-0135 at <http://www.regulations.gov>

³⁴ EPA's expert panel input process is described in the notice "Comment Request; Draft Supporting Materials for the Science Advisory Board Panel on the Role of Economy-Wide Modeling in U.S. EPA Analysis of Air Regulations," *Federal Register*, Vol. 79, No. 24, February 5, 2014, pages 6899 to 6900, at <https://federalregister.gov/a/2014-02471>

On the other hand, if a regulation comes into effect during a period of high unemployment, a change in labor demand due to regulation may affect net overall U.S. employment because the labor market is not in equilibrium. Schmalensee and Stavins point out that net positive employment effects are possible in the near term when the economy is at less than full employment due to the potential hiring of idle labor resources by the regulated sector to meet new requirements (e.g., to install new equipment) and new economic activity in sectors related to the regulated sector.³⁵ In the longer run, the net effect on employment is more difficult to predict and will depend on the way in which the related industries respond to the regulatory requirements. As Schmalensee and Stavins note, it is possible that the magnitude of the effect on employment could vary over time, region, and sector, and positive effects on employment in some time periods, regions or sectors could be offset by negative effects in other periods, regions or sectors. For this reason, they urge caution in reporting partial employment effects since it can “paint an inaccurate picture of net employment impacts if not placed in the broader economic context.”

In Berman and Bui’s (2001, p. 274-75) theoretical model, the change in a firm’s labor demand arising from a change in regulation is decomposed into two main components: output and substitution effects.³⁶

- Output effect: Describes how, if labor-intensity of production is held constant, a decrease in output generally leads to a decrease in labor demand. However, as noted by Berman and Bui, although it is often assumed that regulation increases marginal cost, and thereby reduces output, it need not be the case. A regulation could induce a firm to upgrade to less polluting and more efficient equipment that lowers marginal production costs, for example. In such a case, output could theoretically increase. In the context of the CCR final rule, the output effect would relate to the effect of the CCR rule on the cost and consumption of coal-fired electricity. If consumption decreases due to higher marginal cost of production, employment at coal-fired electric utility plants could also decline.
- Substitution effect: Describes how, holding output constant, regulation affects the labor-intensity of production. Although increased environmental regulation generally results in higher utilization of production factors such as pollution control equipment and energy to operate that equipment, the resulting impact on labor demand is ambiguous. For example, equipment inspection requirements, specialized waste handling, or pollution technologies that are added to the production process may affect the number of workers necessary to produce a unit of output. Berman and Bui (2001) model the substitution effect as the effect of regulation on pollution control equipment and expenditures that are required by the regulation and the corresponding change in labor-intensity of production. In the

³⁵ Schmalensee, Richard, and Robert N. Stavins. “A Guide to Economic and Policy Analysis of EPA’s Transport Rule.” White paper commissioned by Excelon Corporation, March 2011, document ID nr. EPA-HQ-OAR-2011-0135-0054 at <http://www.regulations.gov>

³⁶ The authors also discuss a third component, the impact of regulation on factor prices, but conclude that this effect is unlikely to be important for large competitive factor markets, such as labor and capital. Morgenstern, Pizer and Shih (2002) use a very similar model, but they break the employment effect into three parts: 1) the demand effect; 2) the cost effect; and 3) the factor-shift effect. See Morgenstern, Richard D., William A. Pizer, and Jhih-Shyang Shih. “Jobs Versus the Environment: An Industry-Level Perspective.” *Journal of Environmental Economics and Management* 43 (2002): 412-436, document ID nr. EPA-HQ-OAR-2011-0135-0057 at <http://www.regulations.gov>

context of the CCR final rule, the substitution effect would relate to the coal-fired electric utility industry's pollution control activities in response to the requirements of the rule, which could translate into changes in labor at the CCR management units and elsewhere at the coal-fired electricity plants themselves.

In summary, as the output and substitution effects may be both positive, both negative or some combination, standard neoclassical theory alone does not point to a definitive net effect of regulation on labor demand at regulated firms.

C.1.2 Employment Impact Analysis

The CCR final rule may affect employment in at least seven sectors or sub-sectors:

1. Coal-fired electric utilities
2. Pollution control supplier industries
3. Virgin material suppliers
4. Coal mining
5. Natural gas extraction
6. Natural gas electricity plants
7. Sectors affiliated with constructing new gas power plants

First, this analysis qualitatively describes potential employment impacts for the first three of these sectors: coal-fired electricity plants, pollution control manufacturers, and virgin material suppliers. This analysis then uses IPM output to estimate labor effects for five of the sectors: coal mining, natural gas extraction, and natural gas electricity plants, and the sectors affiliated with constructing new gas power plants.

C.1.2.1 Coal-Fired Electricity Utilities Sector

For the CCR final rule, the Integrated Planning Model (IPM,³⁷) predicts that total coal-fired generating capacity is expected to decrease by approximately 0.34% in years 2020, 2025, and 2030 due to the CCR final rule. Furthermore, IPM predicts the CCR final rule to retire an aggregate of 0.80 GW of coal-fired electricity for years 2020, 2025, and 2030 compared to the baseline.

Given the relatively small effect of the CCR final rule on total capacity and boiler retirements, EPA expects any decrease in labor used by the coal-fired electricity utility sector to be small as well. Changes in employment may occur, however, due to incorporation of pollution controls and overall changes in the labor intensity of CCR management. Demand for labor in the regulated industry may change in response to the thirteen pollution controls under the CCR final rule. **Exhibit C-1** summarizes the RIA's estimated costs of these thirteen pollution controls under a 7% discount rate, as well as each pollution control's respective share of total pollution control costs expected from the CCR final rule.

³⁷ See **Section B** for a full description of the IPM model, analysis, and results.

Exhibit C-1 Incremental CCR Management Costs to the Electric Utility Industry for Compliance with EPA's 2015 CCR Final Rule (annualized \$millions per year 2013\$)			
CCR Pollution Control Requirement	7% discount rate		
	Annualized	Present value	Percent
A. Unit-level pollution control costs			
1. Groundwater monitoring	\$2.8	\$39.9	0.6%
2. Bottom liners (composite or equivalent)	\$297	\$4,230	58.5%
3. Leachate collection systems (landfills only)	\$18.4	\$263	3.6%
4. Fugitive CCR dust controls	\$3.36	\$48	0.7%
5. Stormwater run-on/run-off controls	\$13.0	\$186	2.6%
6. Location restrictions	\$20.0	\$285	3.9%
7. Closure capping	\$12.0	\$171	2.4%
8. Post-closure groundwater monitoring (30 years)	\$0.04	\$0.61	0.01%
9. CCR impoundment structural integrity requirements	\$11.1	\$158	2.2%
B. Other CCR rule costs			
10. CCR contaminated groundwater cleanup corrective action	\$19.1	\$273	3.8%
11. Reporting & recordkeeping	\$27.3	\$389	5.4%
12. Conversion from wet to dry CCR handling (if decide in lieu of retrofitting with composite liners)	\$57.3	\$818	11.3%
13. Dewater & capping costs for inactive CCR impoundments	\$26.7	\$381	5.3%
Subtotal Industry Costs =	\$508	\$7,240	100%
Source: Exhibit ES-A and Exhibit 9-M of EPA's December 2014 Regulatory Impact Analysis (RIA) for the CCR final rule. Note: Except for location restrictions, all unit-level CCR pollution control costs cannot be dissociated due to nonlinearity in the cost estimation modeling process. See Section 4.2 of the RIA for the CCR final rule for additional information. As a result, relative costs for unit-level pollution controls are assigned based on the relative unit cost of these requirements and weighted by the number of existing and new landfills subject to these requirements.			

The two largest pollution control cost items, installation of composite bottom liners and conversion to dry handling in lieu of retrofitting with composite liners, together comprise nearly 70% of all industry costs for the CCR final rule. As described in **Section B.2.1.3** and **Attachment C**, installation of bottom liners is a 100% capital cost³⁸ and conversion from wet to dry CCR handling is 92% capital cost. These two pollution controls total to \$354 million annually, and \$350 million are attributed to capital costs for pollution control equipment and installation. These capital costs are not expected to have a significant impact on employment at coal-fired plants, but could increase employment in industries that manufacture and install pollution control equipment (for a discussion on those effects, see **Section C.1.2.2** below).

The remaining roughly 11 pollution controls that comprise 30% of total pollution control costs summarized above in **Exhibit C-1** contain a relatively stronger mix of both capital and O&M costs. As noted above, capital costs should not have a significant impact on employment at coal-fired plants. However, the O&M costs attributable to pollution control requirements could

³⁸ The assumption is that the utility does not apply its own labor to installation of liners but instead hires a contractor. Thus the expenditure is 100 percent capital.

produce a positive employment impact in the regulated industry. O&M includes labor costs for the maintenance, repair, and operations of pollution control equipment, and thus some or all of O&M costs transfer to employment gains in the regulated industry. **Section B.2.1.3** estimates that only 4% of all 13 CCR pollution control costs are attributable to O&M, and not necessarily all O&M costs are directly transferrable to employment gains. Thus the positive employment impacts due to O&M are likely to be small.

One way to get a rough sense of the labor impacts of O&M pollution control impacts at coal-fired electricity plants, given the cost estimates for complying with the rule, is to consider an estimate of the ratio of workers to each \$1 million of expenditures in that sector.³⁹ The remainder of this analysis calls such an estimate a “*jobs ratio*.” These estimates have serious limitations. They are averages for the sectors, covering all the activities in those sectors; they may not be representative of the labor required when expenditures are required on specific activities, or when manufacturing processes change sufficiently that labor intensity changes. In addition, these estimates do not include changes in sectors that supply inputs to the examined sectors.

NAICS code 221112 represents the coal-fired electric utilities sector. To estimate the jobs ratio for the coal-fired electric utilities sector, this analysis obtained NAICS 221112 employee counts from the 2011 County Business Patterns and cost of production from the 2013 Electric Power Annual, both of which present the most recent data for NAICS 221112. Since the most recent count of employees is from 2011, EPA converted the cost of production from 2013 to 2011 dollars using the Consumer Price Index. In spite of this adjustment, EPA notes that combining data from two different sources is less than ideal since the methods and assumptions used to create each data set varied. **Exhibit C-2** below presents the calculation.

As discussed above, this analysis only considers the O&M costs of electric utilities. **Exhibit C-3** presents the annual O&M compliance costs of the CCR final rule under both 7% and 3% discount rates.

³⁹ This method is adopted from EPA’s Regulatory Impact Analysis for the “Control of Air Pollution from Motor Vehicles: Tier 3 Motor Vehicle Emission and Fuel Standards Rule,” March 2014, EPA-420-R-14-005.

Exhibit C-2			
Coal-Fired Electric Utility Industry 2011 Jobs Ratio			
	A	B	C (B/A)
Industry	Cost of Production	Count of paid employees	Jobs Ratio per \$million
Coal-Fired Electric Utility (NAICS 221112) ^a	\$85,361,552,000	72,192	0.85
Notes: ^a EPA used Cost of Production from the 2013 Electric Power Annual (column A), and Count of Paid Employees from the 2011 County Business Patterns (Column B). Both of these data sources provided the most recent data available for this NAICS code. In order to accurately reflect the Jobs Ratio (2011 Count of Employees per 2013 Cost of Production), Cost of Production was converted to 2011 dollars using Consumer Price Index.			

Exhibit C-3		
Annual O&M Compliance Costs of the CCR Final Rule		
	A	B (A x 4%)
Discount rate:	Annualized compliance cost for CCR Final Rule (2013\$)	O&M ^a (4% of cost)
7%	\$509,000,000	\$20,360,000
3%	\$735,000,000	\$29,400,000
^a O&M cost percentage component estimated in Section B.4.1.3 of this document.		

Exhibit C-2 and **Exhibit C-3** summarize information with the goal of lending insight into the possible magnitude of labor impacts at coal-fired electric plants due to the CCR rule. They reinforce the notion that employment gains due to O&M are likely to be minimal.

C.1.2.2 Pollution Controls Supplier Industries

The 13 CCR pollution costs incurred by the coal-fired electricity industry listed in **Exhibit C-1** above are primarily capital investments for goods and services needed to comply with the CCR final rule (see **Attachment C**). These costs to the regulated industry translate into increased demand to the firms manufacturing and installing the equipment and could potentially spur increased employment in that industry.

The largest of the 13 CCR pollution controls is the installation of bottom liners, of which 100% is capital cost attributed to the purchase price and installation of the liner. As of 1994, the cost of an installed Geosynthetic-Clay Liner (GCL) ranged from \$0.66 to \$0.94 per square foot, and factors affecting the cost of a GCL include shipping distance, total area of installation, market demand, and season.⁴⁰ Bottom liner costs contribute \$297 million annually to the costs of the CCR final rule. If bottom liner manufacturing and installation is labor intensive, or shipping distances are substantial, the increased demand for bottom liners by coal-fired electricity plants could be transmitted into positive employment impacts for firms that provide bottom liner goods and services.

The second largest of the 13 CCR pollution controls is conversion to dry handling, which is a 92% capital cost attributed to the purchase price and installation of the equipment. **Section**

⁴⁰ Costs converted to 2013 dollars using CPI. Source: USEPA (1997), "Geosynthetic Clay Liners Used in Municipal Solid Waste Landfills", EPA530 -F-97-002.

4.2.13 of EPA's RIA for the 2015 CCR final rule summarizes the various technologies used for wet-to-dry CCR conversion. Conversion to dry capital costs contribute \$53 million annually to the costs of the CCR final rule. Depending on how labor intensive it is to engineer, manufacture, and install wet-to-dry conversion systems, there could be a positive employment impact for industries involved in this pollution control.

The remaining 11 CCR pollution control items comprise a much smaller shares of total CCR final rule costs, but follow similar employment impacts on pollution control industries as bottom liners and dry conversion systems. Much of the costs to these pollution control items are capital, implying that the regulated industry will pay firms to develop, manufacture, and install the equipment. If these processes are labor intensive, the increased demand could similarly be transmitted into positive employment effects for the pollution control industries.

EPA expects the employment effect in the pollution controls industry will be positive and the magnitude determined by the labor intensity of production and installation of the specific controls.

C.1.2.3 Virgin Materials Suppliers

EPA's RIA for the CCR final rule uses a linear-programming approach to estimate the extent to which the increase in CCR disposal costs associated with the final rule motivates coal-fired power plants to manage their CCR through beneficial use rather than disposal. For each ton of CCR generated by a coal-fired power plant, the analysis determines whether beneficial use or disposal is the most economical management option, based on both the private benefits and costs of beneficial use.

As modeled in the **Section 5.3** of the RIA, beneficial use of CCR is expected to increase under the final rule. The increased beneficial use of CCRs means that manufacturers of concrete, wallboard, and fill will reduce their demand for virgin raw materials and substitute with CCRs, which could result in a potential negative employment impact for firms that manufacture and distribute the affected virgin raw materials. According to **Exhibit C-4**, approximately \$45 million annually will be diverted away from Portland cement, gypsum ore, and virgin fill raw materials. Depending on how labor intensive it is to supply these goods, virgin materials industries could see a decrease in employment due to the CCR final rule.

Exhibit C-4 Lost Future Annual Sales Revenues to Virgin Raw Materials Suppliers From Induced* Future Increase in CCR Beneficial Use Due to the CCR Rule				
Impact Estimation Metrics		Concrete	Wallboard	Structural Fill
1	Average annual future induced increase in tons of beneficially used CCRs due to the CCR final rule ^a	46,488	226,122	5,696,574
2	Price per ton of virgin raw materials ^b	\$93.57	\$7.50	\$6.79
3	Annual lost revenue to raw materials suppliers	\$4,349,882	\$1,695,915	\$38,679,737
Notes: * Induced future increase is modeled in EPA's December 2014 RIA for the CCR final rule; this modeling comports with the "avoided disposal cost" business behavior of electric utility plants as defined by the American Coal Ash Association (ACAA), as cited in Section 5.3 of the RIA. ^a Calculated from Exhibit 5-L of EPA's 2014 RIA for the CCR final rule, and scaled downward 22% to reflect the scaling factor applied to the CCR beneficial use benefits category in Section 9.2.4 of the RIA. ^b Prices obtained from Appendix S exhibit S-8 from EPA's 2014 RIA for the CCR final rule.				

An estimate of a jobs ratio can be calculated for virgin raw material industries. The 2007 Economic Census associates "2nd tier" industries that supply raw materials to the "1st tier" cement, gypsum, and fill industries. To estimate jobs ratios in 2nd tier industries, this RIA uses the following approach:

1. Employee count data: Find count of employees at 2nd tier industries associated with supplying virgin raw materials to industries that will beneficially use CCR, then multiply the total number of employees at 2nd tier industries by the ratio of 1st tier delivered cost at 2nd tier industries to total sales revenue at 2nd tier industries.
2. Estimate jobs ratio: The jobs ratio can then be calculated by dividing the count of employees found in the previous step by the 1st tier delivered cost at 2nd tier industries.

The resulting job ratios are summarized in **Exhibit C-5**. Further calculation breakdowns for each of the 2nd tier industries are illustrated in **Attachment G**, **Attachment H**, and **Attachment I**. **Exhibit C-6** presents the estimated ratios alongside the potential lost sales. The suggestion is that the magnitude of labor impacts is likely quite small.

Exhibit C-5 Industries That Beneficially Use CCRs ("1st Tier") and the Respective Job Ratios of Industries Potentially Negatively Impacted by 1st Tier Beneficial Use ("2nd Tier")						
	A	B	C	D	E (B * (D / C))	F (E / D)
NAICS	Industries that Beneficially Use CCR (1st Tier Industries)	Paid Employees in 2nd Tier Industries	Sales Revenues at 2nd tier industries (\$million)	Delivered Cost to 1st Tier Industries (\$million)	Count of Paid Employees in 2nd Tier affiliated with 1st Tier Delivered Cost	Jobs Ratio per \$million for 2nd tier industry
327310	Cement Manufacturing	125,440	\$34,738.07	\$566.90	1750	3.09
212399	Fill Dirt Pits Mining and/or Beneficiating	394,528	\$904,206.68	\$122.87	354	2.88
327420	Gypsum Product Manufacturing	198,033	\$75,527.30	\$1,336.78	4041	3.02
Notes: - See Attachment E , Attachment F , and Attachment G for a further breakout of job ratios by specific 2 nd tier industries - Columns B, C, and D obtained from the 2007 Economic Census.						

Exhibit C-6 Potential Future Lost Sales in Virgin Raw Material Industries Due to Increase in Beneficial Use Under the CCR Final Rule (2013\$)			
	A	B	C
	CCR beneficial use market	Potential lost sales to virgin material industry ^a (\$million)	Jobs ratio ^b
1	Cement Substitute in Concrete	\$4.35	3.09
2	Structural Fill	\$38.68	2.88
3	FGD Gypsum in Wallboard	\$1.70	3.02
Notes: ^a Potential lost sales to virgin material industry from Exhibit C-4 . ^b Jobs ratio for each of the three virgin raw materials categories from Exhibit C-5 .			

C.1.2.4 IPM Analysis Labor Estimates in the Coal-Fired Electric Utility Industry

This section considers the results from IPM (see **Section B.3**) to generate estimates of labor effects in the coal-fired electricity industry. **Attachment F** provides a detailed description of the methodology applied to derive these labor effects. It is important to note that the IPM-derived effects are reported as full-time equivalents (FTEs), the number of total hours worked divided by the maximum number of compensable hours in a full-time schedule. Therefore, an FTE of 1.0 is equivalent to the work conducted by 1 full-time employee over the course of a year. While FTE is a measure of labor, changes in FTEs is not necessarily directly equivalent to the number of jobs added or lost within in a given sector. For example, employees can transition between full- and part-time, work overtime, transition between job functions, etc.

This analysis estimates the CCR final rule will reduce total O&M labor at coal-fired electricity plants by 603 job years (FTEs) by the year 2020. This estimate is a constant rate; that is, by 2020 FTEs are estimated to decrease by 603, and remain at that level on a going forward basis. The FTE estimate reflects projected adjustments within the power sector including increases in natural gas production and decreases in coal-based production. It does not reflect short term

labor increases to install controls as discussed in the prior sections. For context, employment in the Electric Power Industry was roughly 394,000 workers in 2013.⁴¹

C.1.2.5 Coal Mining and Natural Gas Extraction

This analysis considers the results from IPM to generate estimates of labor effects in the coal mining and natural gas extraction industries. **Attachment F** provides a detailed description of the methodology applied to derive these labor effects. As noted above, results are reported as FTEs, which are not equivalent to the number of jobs added or lost within in a given sector. **Exhibit C-7** shows the estimated labor effects of the CCR rule on coal mining and natural gas extraction.

Exhibit C-7			
Estimated Coal Mining and Natural Gas Extraction Labor Impacts Due to the CCR Final Rule (Job-Years of Employment in Year*)			
	2020	2025	2030
Total Coal Mining Labor	-209	-147	-77
Midwest Basin	0	0	0
Western Basin	2	-13	-16
Appalachian	-211	-134	-61
Total Natural Gas Extraction Labor	130	152	98
*Job-year estimates are Full Time Equivalent (FTE). See Attachment F for estimation methodology.			

C.1.2.6 Natural Gas Plants

The IPM labor analysis also considers potential labor effects at power plants that generate electricity using natural gas. **Attachment F** provides a detailed description of the methodology applied to derive these labor effects. As noted above, these results are reported as FTEs, which are not equivalent to the number of jobs added or lost within a given sector. **Exhibit C-8** shows the estimated labor effects of the CCR rule on plants that generate electricity using natural gas. Labor is expected to increase in this subsector as former coal-fired plants shift away from coal towards natural gas.

Exhibit C-8			
Estimated O&M Labor Impacts at Natural Gas Power Plants Due to the CCR Final Rule (Job-Years of Employment in Year*)			
	2020	2025	2030
Total labor at gas powered plants	98	166	171
* Job-year estimates are Full Time Equivalent (FTE) See Attachment F for estimation methodology.			

⁴¹ U.S. Bureau of Labor Statistics. "Current Employment Survey Seasonally Adjusted Employment for Electric Power Generation, Transmission, and Distribution (national employment)." Series ID: CES4422110001. Data extracted on: February 19, 2014. Available at: <<http://www.bls.gov/ces/data.htm>>.

C.1.2.7 Sectors Affiliated with New Plant Construction

IPM projects that electricity utilities will construct new natural gas plants as an alternative to coal-fired electricity generation. This analysis applies that IPM result to determine construction labor additions, and **Attachment F** provides a detailed description of the methodology applied to derive these labor effects. **Exhibit C-9** shows the estimated labor effects of the CCR rule on new gas plant construction, measured in FTEs per year during construction, expected to take place over a three year period.

Exhibit C-9			
Estimated One-time Labor Impacts from Construction of New Natural Gas Plants Due to the CCR Final Rule (Job-Years of Employment in Year*)			
	2020	2025	2030
New Gas Plant Construction Labor	357	605	620
* Job-year estimates are Full Time Equivalent (FTE) See Attachment F for estimation methodology. FTEs for new plant construction are expected to take place over a three year period.			

C.1.3 Conclusion

The overall effect of environmental regulation on employment is far reaching and difficult to disentangle from the effect of other economic factors. Complying with a new or more stringent regulation may require additional inputs, including labor, and may alter the relative proportions of labor and capital used by regulated firms (and firms in other relevant industries) in their production processes. As such, the quantitative estimates in this employment analysis for the CCR final rule are not comprehensive; they form only partial estimates for illustrative purposes. This employment evaluation does not reach a quantitative estimate of the overall employment effects of the CCR final rule on employment or even whether the net effect will be positive or negative. However, given that the expected increase in production costs to the coal-fired electric utility industry is relatively small, the magnitudes of all effects combined can also be expected to be small as well.

Attachments

- A. EPA Base Case v.5.13 Regions
- B. Map of EPA Base Case Regions v.5.13
- C. Capital vs O&M Cost Components of CCR Final Rule - Annualized Values @ 7% Discount Rate (millions of 2013\$)
- D. Fixed O&M and Variable O&M Estimates for Coal-Fired Electricity Utility Power Plants
- E. Avoidable vs. Unavoidable Cost Estimates for the CCR Final Rule - Annualized Values @ 4.77% Discount Rate (millions of 2013\$)
- F. Projected Sectoral Employment Impact Analysis Methodology
- G. Industries Affiliated with Cement Manufacturing (NAICS 327310) Potentially negatively Impacted by CCR Beneficial Use, and their Respective Jobs Ratios
- H. Industries Affiliated with Fill Dirt Pits Mining and/or Beneficiating (NAICS 212399) Potentially Negatively Impacted by CCR Beneficial Use, and their Respective Jobs Ratios
- I. Industries Affiliated with Gypsum Product Manufacturing (NAICS 327420) Potentially Negatively Impacted by CCR Beneficial Use, and Their Respective Job Ratios
- J. Percentage of Present Value Costs & Present Value Benefits for the CCR Final Rule Which Are Estimated to Occur Between Alternative Time Intervals

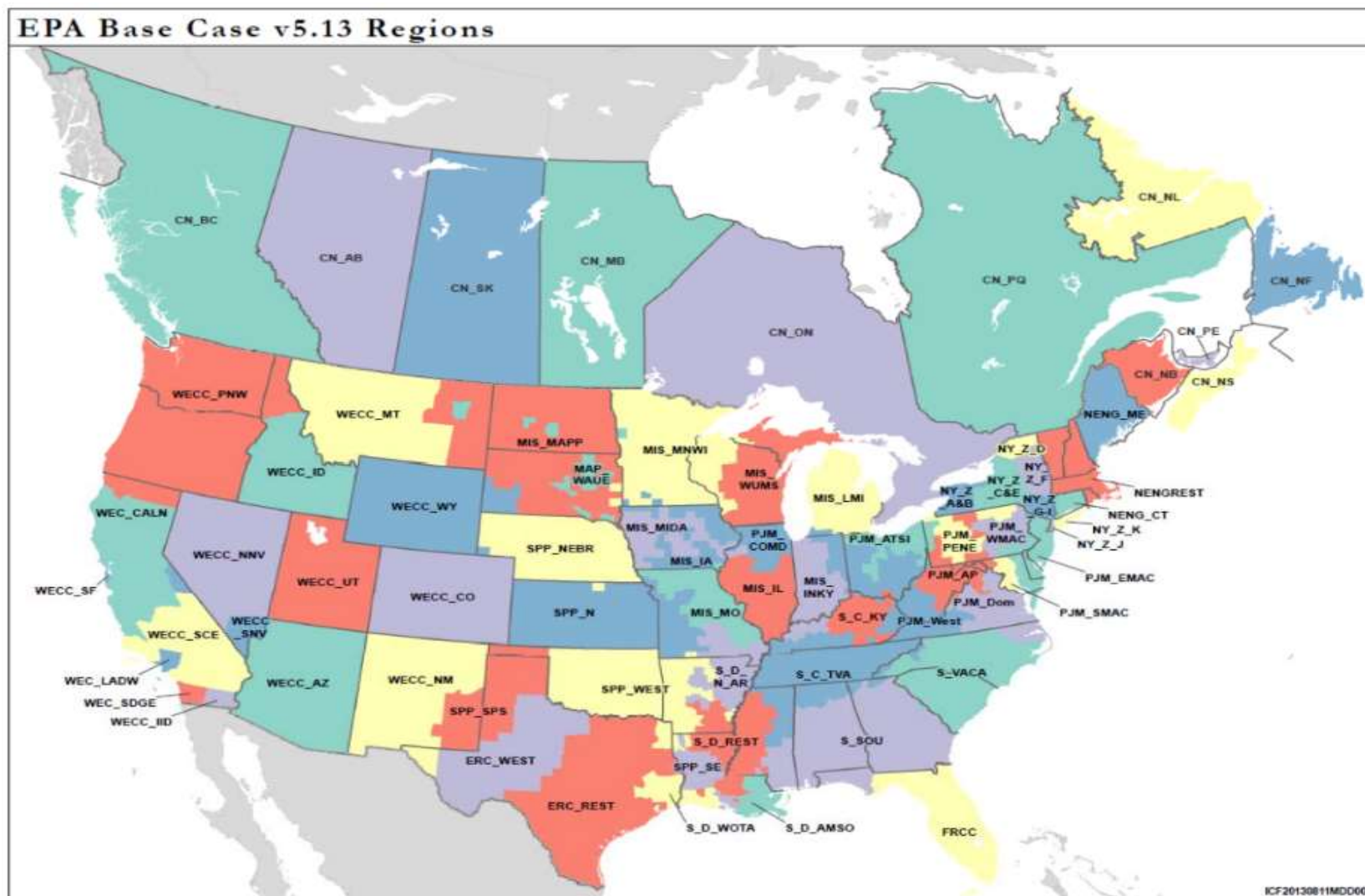
Attachment A

EPA Base Case v.5.13 Regions

NERC Assessment Region	AEO 2013 NEMS Region	Model Region	Model Region Description
ERCOT	ERCT (1)	ERC_FRNT	ERCOT_Tenaska Frontier Generating Station
		ERC_GWAY	ERCOT_Tenaska Gateway Generating Station
		ERC_REST	ERCOT_Rest
		ERC_WEST	ERCOT_West
FRCC	FRCC (2)	FRCC	FRCC
MAPP	MROW (4)	MAP_WAUE	MAPP_WAUE
		MIS_MAPP	MISO_MT, SD, ND
MISO	MRGE (3), RFCW (11)	MIS_WUMS	MISO_Wisconsin- Upper Michigan (WUMS)
		MIS_JA	MISO_Iowa
	MROW (4)	MIS_MIDA	MISO_Iowa-MidAmerican
		MIS_MNWI	MISO_Minnesota and Western Wisconsin
	RFCM (10)	MIS_LMI	MISO_Lower Michigan
	RFCW (11), SRCE (15)	MIS_INKY	MISO_Indiana (including parts of Kentucky)
	SRGW (13)	MIS_IL	MISO_Illinois
		MIS_MO	MISO_Missouri
ISO-NE	NEWNE (5)	NENG_CT	ISONE_Connecticut
		NENG_ME	ISONE_Maine
		NENGREST	ISONE_MA, VT, NH, RI (Rest of ISO New England)
NYISO	NYCW (6)	NY_Z_J	NY_Zone J (NYC)
	NYLI (7)	NY_Z_K	NY_Zone K (LI)
	NYUP (9)	NY_Z_A&B	NY_Zones A&B
		NY_Z_C&E	NY_Zone C&E
		NY_Z_D	NY_Zones D
		NY_Z_F	NY_Zone F (Capital)
		NY_Z_G-I	NY_Zone G-I (Downstate NY)
PJM	RFCE (9)	PJM_EMAC	PJM_EMAAC
		PJM_PENE	PJM_PENELEC
		PJM_SMAC	PJM_SWMAAC
		PJM_WMAC	PJM_Western MAAC
		PJM_AP	PJM_AP
	RFCW (11)	PJM_ATSI	PJM_ATSI
		PJM_COMD	PJM_CorEd
SERC-E	SRVC (18)	PJM_West	PJM_West
	SRVC (18)	PJM_Dom	PJM_Dominion
SERC-N	SRCE (19)	S_VACA	SERC_VACAR
		S_C_KY	SERC_Central_Kentucky
SERC-SE	SRSE (14)	S_C_TVA	SERC_Central_TVA
		S_SOU	SERC_Southeastern
SERC-W	SRDA (12)	S_D_AMSO	SERC_Delta_Amite South (including DSO)
		S_D_N_AR	SERC_Delta_Northern Arkansas (including AECI)
		S_D_REST	SERC_Delta_Rest of Delta (Central Arkansas)
		S_D_WOTA	SERC_Delta_WOTAB (including Western)
SPP	MROW (4)	SPP_NEBR	SPP_Nebraska
	SPNO (17), SROW (13)	SPP_N	SPP_North- (Kansas, Missouri)
		SPP_KIAM	SPP_Kiamichi Energy Facility
	SPSO (18)	SPP_SE	SPP_Southeast (Louisiana)
		SPP_SPS	SPP_SPS (Texas Panhandle)
Basin (BASN)	NWPP (21)	WECC_ID	WECC_Illinois
		WECC_NNV	WECC_Northern Nevada
Northern California (CALN)	CAMX (20)	WECC_UT	WECC_Utah
		WECC_CALN	WECC_Northern California (including SMUD)
Southern California (CALS)	AZNM (19)	WECC_SF	WECC_San Francisco
	CAMX (20)	WECC_IID	WECC_Imperial Irrigation District (IID)
		WECC_LADWP	WECC_LADWP
Northwest (NORW)	NWPP (21)	WECC_SDGE	WECC_San Diego Gas and Electric
		WECC_SCE	WECC_Southern California Edison
Rockies (Rock)	NWPP (21), RMPA (22)	WECC_MT	WECC_Montana
		WECC_PNW	WECC_Pacific Northwest
Desert Southwest (DSW)	AZNM (19)	WECC_WY	WECC_Wyoming
		WECC_CO	WECC_Colorado
		WECC_AZ	WECC_Arizona
		WECC_NM	WECC_New Mexico
Canada		WECC_SHV	WECC_Southern Nevada
		CN_AB	Alberta
		CN_BC	British Columbia
		CN_MB	Manitoba
		CN_NB	New Brunswick
		CN_NF	Newfoundland
		CN_NL	Labrador
		CN_NS	Nova Scotia
		CN_ON	Ontario
		CN_PE	Prince Edward Island
		CN_PQ	Quebec
		CN_SK	Saskatchewan

Source: NEEDS v.5.13 user guide, available at
http://www.epa.gov/powersectormodeling/docs/v513/NEEDS_513_User_Guide.pdf

Attachment B
Map of EPA Base Case Regions v.5.13



Source: NEEDS v.5.13 user guide, available at http://www.epa.gov/powersectormodeling/docs/v513/NEEDS_513_User_Guide.pdf

Attachment C Capital vs O&M Cost Components of CCR Final Rule - Annualized Values @ 7% Discount Rate (millions of 2013\$)						
Pollution Control	RIA Incremental Cost	Percent Capital Cost*	Percent O&M Cost*	Capital Cost (B * C)	O&M Cost (B * D)	Rationale for Capital / O&M Selection
1. Groundwater monitoring during active operational lifespan of LFs & SIs	\$3.70	14%	86%	\$0.52	\$3.18	Based on pages 4-20 and 4-21 of the report “Estimation of Costs for Regulating Fossil Fuel Combustion Ash Management at Large Electric Utilities under Part 258,” November 30, 2005, document ID nr EPA-HQ-RCRA-2006-0796-0469 at http://www.regulations.gov See footnote 2 for estimation strategy.
2. Bottom composite liners	\$387	100%	0%	\$386.84	\$0.00	Assumed 100% capital cost (assumed not subject to O&M because are covered by waste over lifespan)
3. Leachate collection systems (only for LFs)	\$31.3	100%	0%	\$31.29	\$0.00	Assumed 100% capital cost (assumed not subject to O&M because are covered by waste over lifespan)
4. Fugitive CCR dust controls	\$4.92	59%	41%	\$2.90	\$2.02	Based on Appendix K of the 2014 CCR RIA.
5. Stormwater run-on/run-off controls	\$16.1	100%	0%	\$16.05	\$0.00	Assumed 100% capital cost (assumes solely for front-end capital cost for construction of stormwater basin)
6. Location restrictions		N/A	N/A			Location restrictions require plants to transfer waste for offsite disposal. Such costs are reflected in the other pollution controls and thus this pollution control does not directly reflect the capital and O&M breakout.
7. Closure capping	\$15.7	40%	60%	\$6.28	\$9.42	Based on page 4-30 of “Estimation of Costs for Regulating Fossil Fuel Combustion Ash Management at Large Electric Utilities under Part 258”, 30 Nov 2005, DPRA Inc. for EPA Office of Solid Waste, document ID nr. EPA-HQ-RCRA-2006-0796-0469 at http://www.regulations.gov See footnote 3 for estimation strategy.
8. Post-closure groundwater monitoring (30 years)	\$0.058	14%	86%	\$0.01	\$0.05	Assumed same as groundwater (item 1) above.
9. Structural integrity requirements for SIs	\$11.0	88%	12%	\$9.69	\$1.32	Structural integrity costs include both costs to abide by structural integrity requirements and to conduct remedial action when required, thus follows the same framework as corrective action costs in item 10.
10. Corrective action of CCR contaminated groundwater (if detected above MCLs)	\$19.2	88%	12%	\$16.91	\$2.31	Based on Exhibit 14-4 of the 2004 EPA report, “Cleaning up the Nation’s Waste Sites: Markets and Technology Trends,” http://www.clu-in.org/download/market/2004market.pdf . - From 26 Project Sample (US EPA 1999): \$31 O&M per 1,000 gallons annually / \$250 Capital per 1,000 gallons annually = 12.4% - From 32 Project Sample (US EPA 2001): \$32 O&M per 1,000 gallons annually / \$280 Capital per 1,000 gallons annually = 11.8% - Average of 12.4% and 11.8% equals approx. 12% O&M

Attachment C						
Capital vs O&M Cost Components of CCR Final Rule - Annualized Values @ 7% Discount Rate (millions of 2013\$)						
Pollution Control	RIA Incremental Cost	Percent Capital Cost*	Percent O&M Cost*	Capital Cost (B * C)	O&M Cost (B * D)	Rationale for Capital / O&M Selection
11. Reporting and recordkeeping		N/A	N/A			Not submitted to IPM, because these costs are calculated at the national level and cannot be parsed to individual power plant boiler costs. At a 7% discount rate, reporting and recordkeeping encompasses 5.4% of total industry costs (@ 7% discount rate)
12. Conversion to dry handling	\$42.4	92%	8%	\$39.02	\$3.39	Calculated according to Section 4.2.13 of the RIA
13. Cost for inactive impoundments (dewater and closure cap)		N/A	N/A			Not submitted to IPM, because these costs are calculated at the national level and cannot be parsed to individual power plant boiler costs. Cost for inactive impoundments encompasses 5.2% of total industry costs (@ 7% discount rate)
Total cost =	\$531.21	Subtotal =		\$509.51	\$21.69	
Percent =	100%	Percent =		96%	4%	
1. • Capital Cost - o (\$5,433 / well* 12 wells) + \$6332 = \$71,528 cost - o \$71,528 / (13.801 PWF) = \$5,182.81 annualized capital cost for groundwater monitoring - o \$5,182.81 / \$36,925.11 = 14% of GW annualized cost is capital cost • O&M Cost - o (\$1,150 sample * 2 per year) = \$2,300 - o \$2,300 * (13.801 PWF) = \$31,742.30 annualized O&M cost for groundwater monitoring - o \$31,742.30 / \$36,925.11 = 85% of GW annualized cost is O&M cost • Total Annualized Groundwater monitoring cost for purpose of computing percentages: - o \$5,182.81 + \$31,742.30 = \$36,925.11 2. • Capital Cost: - o Took the average of the total capital costs for the five sizes ranging from 14.45 acres to 2,597.1 acres size for synthetic cap. - o Average total capital cost = \$104,270,308 - o Annualized (average) total capital cost = \$7,555,272/ \$18,788,260 total annual capital and O&M cost = 40% • O&M Cost: - o Took the average of the total O&M costs for the five sizes ranging from 14.45 acres to 2,597.1 acres size for synthetic cap. - o Average annualized O&M cost = \$11,232,988 / \$18,788,260 total annual capital and O&M cost = 60%						

Attachment D						
Fixed O&M and Variable O&M Estimates for Coal-Fired Electricity Utility Power Plants						
		Plant Characteristics		Plant O&M Costs (2012\$)		
A		B	C	E	F	G
Coal		Nominal Capacity (MW)	Heat Rate (Btu/kWh)	Fixed O&M Cost (\$/kW-yr)	Variable O&M Cost (\$/MWh)	Variable O&M (%)
1	Single Unit Advanced PC	650	8,800	\$37.80	\$4.47	11%
2	Dual Unit Advanced PC	1,300	8,800	\$31.18	\$4.47	13%
3	Single Unit Advanced PC with CCS	650	12,000	\$80.53	\$9.51	11%
4	Dual Unit Advanced PC with CCS	1,300	12,000	\$66.43	\$9.51	13%
5	Single Unit IGCC	600	8,700	\$62.25	\$7.22	10%
6	Dual Unit IGCC	1,200	8,700	\$51.39	\$7.22	12%
7	Single Unit IGCC with CCS	520	10,700	\$72.83	\$8.45	10%
AVERAGE =						11%
Notes: - columns A through F obtained from: US Energy Information Administration, "Capital Cost for Electricity Plants: Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants," published April 12, 2013, accessed August 18, 2014 from http://eia.gov/forecasts/capitalcost/ - each of the seven rows above represent model power plants - PC short for "pulverized coal" - CCS short for "carbon capture storage" - IGCC short for "integrated gasification combined cycle"						

Attachment E

Avoidable vs. Unavoidable Cost Estimates for the CCR Final Rule - Annualized Values @ 4.77% Discount Rate (millions of 2013\$)

Pollution Control	RIA Incremental Cost	Avoidable or Unavoidable Cost*	Rationale for Avoidable / Unavoidable Selection
1. Groundwater monitoring during active operational lifespan of LFs & SIs	\$3.70	Avoidable	Required only for active CCR LFs & SIs; if a power plant ceases burning coal, the CCR LFs & SIs become inactive (i.e., cease receiving CCR) and must close, which requires post-closure GW monitoring (cost item #8) rather than operational GW monitoring (cost item #1)
2. Bottom composite liners	\$387	Avoidable	Incurred only if power plant continues burning coal and either retrofits existing SIs, or builds new LFs or SIs
3. Leachate collection systems (only for LFs)	\$31.3	Avoidable	Incurred only if power plant continues burning coal and builds new LFs
4. Fugitive CCR dust controls	\$4.92	Avoidable	Incurred only if power plant continues burning coal with active LFs or SIs
5. Run-on/run-off controls	\$16.1	Avoidable	Incurred only if power plant continues burning coal with active LFs or SIs
6. Location restrictions	\$30.5	Unavoidable	Avoidable only if a power plant ceases burning coal before Aug 2018. Otherwise, required (unavoidable) for all power plants which are burning coal with active LFs or SIs; within 42 months after publication of the CCR final rule in the Federal Register (e.g., Feb 2015 + 42 months = Aug 2018); assume no plants cease burning coal prior to Aug 2018 and assigned solely as "unavoidable" in this table.
7. Closure capping	\$15.7	Unavoidable	Required for all power plants which cease burning coal; LFs & SIs which cease receiving CCR must be closed and capped.
8. Post-closure groundwater monitoring (30 years)	\$0.058	Unavoidable	Required for all power plants which cease burning coal; LFs & SIs which cease receiving CCR must be closed, capped and 30-years of post closure GW monitoring.
9. Structural integrity requirements for SIs	\$11.0	Avoidable	Incurred only if power plant continues burning coal with active SIs
10. Corrective action of CCR contaminated groundwater (if detected above MCLs)	\$19.2	Unavoidable	Required if corrective action is triggered during GW monitoring of operating LFs & SIs or during 30-year post closure phase of closed LFs & SIs regardless of whether power plant is burning coal.
11. Reporting and recordkeeping		N/A	Not submitted to IPM, because these costs are calculated at the national level and cannot be parsed to individual boiler costs. At a 7% discount rate, reporting and recordkeeping encompasses 5.4% of total industry costs (@ 7% discount rate)
12. Conversion to dry handling	\$42.4	Avoidable	Incurred only if plant decides to convert to dry; if a power plant ceases burning coal it will avoid dry conversion business decisions.
13. Cost for inactive impoundments (dewater and closure cap)		N/A	Not submitted to IPM, because these costs are calculated at the national level and cannot be parsed to individual boiler costs. Cost for inactive impoundments encompasses 5.2% of total industry costs (@ 7% discount rate)
Total cost =	\$561.71		
Sub-total avoidable =	\$496.23	88%	
Sub-total unavoidable =	\$65.48	12%	
QC check sums =	\$561.71	100%	

Notes:

*Unavoidable cost = CCR rule pollution control requirement cost will still be incurred in the future after the power plant ceases burning coal.

Attachment F: Projected Sectoral Employment Impact Analysis Methodology

The analytical approach used in this analysis to estimate the amount of labor directly affected by the final CCR rule is a bottom-up engineering method combining EPA's cost analysis of the final CCR rule with data on labor productivity and wage rates. This approach is different from a traditional national unemployment impact analyses. Rather than projecting net employment impacts throughout the U.S. economy, the engineering based analysis focuses solely on the direct impact on labor utilization in industries closely involved with electricity generation. The engineering based labor analysis does not consider indirect impacts on other sectors affected by the changes in the power sector, nor on the indirect multiplier effects associated with changes in the total payrolls in the directly affected power sectors.

The engineering approach estimates labor changes measured as the change in the number of people employed in the power generation and directly related sectors. The changes in employment are measured as changes in the number of job-years⁴² utilized in a single year in the directly affected portions of the power sector. The quantified employment impacts include not only changes in the amount of labor involved with operating and maintaining electricity generating units, but also changes in the amount of labor used to manufacture and install new generating units and to extract and transport coal and natural gas to the generating units.

This direct labor analysis relies on projections and costing analysis from the Integrated Planning Model⁴³ (IPM), which uses industry-specific data and assumptions to estimate costs and energy impacts of the CCR rule. See **Section B.2** for further background on IPM.

The quantified labor impacts of the CCR rule include both one-time and recurring employment effects. The one-time employment effects are the increased construction-related labor demand needed to build new gas-fired generating units needed to replace retiring coal-fired units.

Recurring employment effects include:

- (1) The increase in the annual amount of labor needed to extract and transport the additional natural gas needed at the new gas-fired generating units (and for increased utilization of existing gas-fired units).
- (2) The increase in the annual amount of labor needed to operate and maintain the new gas-fired generating units.
- (3) The decrease in the annual amount of labor needed to mine and transport coal no longer needed at retiring coal-fired units and decreased utilization of existing coal-fired units.
- (4) The decrease in the annual amount of labor no longer needed to operate and maintain the retired coal generating units.

⁴² Job-years are not individual jobs, but rather the amount of work performed by the equivalent of one full-time individual for one year. For example, 20 job-years in 2020 may represent 20 full-time jobs or 40 half-time jobs in that year.

⁴³ For more detail on IPM's electric load modeling and power system operation, see IPM Ver. 5.13 Base Case documentation (<http://www.epa.gov/powersector> modeling).

Fuel Sector Labor Analysis

The CCR rule labor analysis of the impacts of the decrease in the quantity of coal, and increase in the quantity of natural gas, is based on labor productivity data. The IPM analysis of the final CCR rule provides estimates of the changes in coal usage (in million short tons per year, or MT) and natural gas usage (in millions of BTUs, or MMBTU), in 2020, 2025 and 2030. The changes in direct labor in the fuel sector are calculated using the changes in fuel use and data on labor productivity in fuel supply sector.

The incremental changes to coal labor demand for the CCR rule were calculated based on the three coal supply regions in IPM – Appalachia (Pennsylvania through Mississippi), Interior (Indiana through Texas), and the West (North Dakota through Arizona). Using this approach, estimated changes in coal demand (in short tons) for various coal supplying regions were taken from EPA’s base and policy case runs for CCR rule. These changes were converted to job-years using U.S. Energy information Administration (EIA) data on regional coal mining productivity (in short tons per employee hour), using 2008 labor productivity estimates.⁴⁴

For natural gas demand, labor productivity per unit of natural gas was unavailable, unlike coal labor productivities used above. Most secondary data sources (such as Census and EIA) provide estimates for the combined oil and gas extraction sector. The natural gas labor analysis, therefore, used an adjusted labor productivity estimate for the combined oil and gas sector that accounts for the relative contributions of oil and natural gas in the total sector output (in terms of the value of energy output in million Btu). This estimate of labor productivity was then used with the incremental natural gas demand for the respective IPM runs to estimate the job-years for the specific year (converting the TCF of gas used projected by IPM into million Btu using the appropriate conversion factors). In addition, the pipeline construction costs were estimated using endogenously determined gas market model parameters in IPM used by EPA for the MATS rule (using assumptions for EPA’s Base Case v4.10). This analysis assumed that the need for additional pipeline would be proportionate to those projected for the MATS rule and were hence extrapolated from those estimates.⁴⁵ The job-years associated with the pipeline construction were included in the natural gas employment estimates.

Worker productivity values used for estimating coal mining and gas extraction related job impacts are shown in **Exhibit Attachment F-1** below.

Exhibit Attachment F-1: Labor Productivity in Fuel Supply

Labor Productivity	
Coal (Short tons per employee hour)	
Appalachia	2.91
Interior	4.81
West	19.91
Natural Gas (million Btu per employee hour)	126
Pipeline Construction (Workers per \$Million)	5.1

⁴⁴ From EIA Annual Energy Review, Coal Mining Productivity Data, available at: <http://www.eia.gov/totalenergy/data/annual/showtext.cfm?t=ptb0707>

⁴⁵ See “Employment Estimates of Direct Labor in Response to the Proposed Toxics Rule in 2015”. Technical Support Document, March 2011.

New Natural Gas-Fired Generating Unit Construction

The direct labor needed to install new natural gas-fired generating units in the CCR rule are estimated by extrapolating the labor estimates for new natural-gas units presented in the 2014 proposed CPP RIA.⁴⁶

The IPM estimates of amount of new natural gas generating capacity needed by the CCR rule (e.g., 0.73 GW brought online in 2025) is much smaller than the absolute value of the amount of new natural gas capacity avoided in the proposed CPP RIA (29 GW with Option 1, State Implementation in 2025). The proposed CPP RIA estimates of the amount of new gas capacity avoided in 2025, and the change in the labor associated with building the new gas units in 2025, imply that that 827.3 job-years are needed in each of 3 years to construct 1 GW of new natural gas generating capacity. This new gas construction annual labor factor in 2025 from the proposed CPP RIA is used to estimate the new gas capacity construction labor needs of the CCR rule in 2020, 2025 and 2030.

Generating Unit Operations and Maintenance Labor Analysis

The direct labor analysis of changes in direct labor needed to operate and maintain (O&M) new gas-fired generating units, and the loss of O&M jobs at the retired coal-fired units, is also conducted using the relevant O&M annual labor factors from the proposed CPP analysis.⁴⁷ In the proposed CPP, O&M at gas-fired generating units annually required 227.3 job-years per GW of capacity. O&M at coal-fired generating units annually require 750.0 job-years per GW of capacity. These coal and gas annual O&M labor factors for 2025 from the proposed CPP RIA is used to estimate the changes in O&M labor needs of the CCR rule in 2020, 2025 and 2030.

⁴⁶ See Chapter 6 Section 6.6.1 and Appendix 6A of the RIA for the CPP rule, available at: <http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf>

⁴⁷ Ibid.

Attachment G Industries Affiliated with Cement Manufacturing (NAICS 327310) Potentially Negatively Impacted by CCR Beneficial Use, and their Respective Jobs Ratios						
A		B	C	D	E (B * (D / C))	F (E / D)
NAICS	2nd Tier Industry	Paid Employees in 2nd Tier Industries	Sales Revenues at 2nd tier industries (millions of 2007\$)	Delivered Cost to 1st Tier Industries (millions of 2007\$)	Count of Paid Employees in 2nd Tier affiliated with 1st Tier Delivered Cost	Jobs Ratio per \$million
322224	Paper shipping sacks & multiwall bags	10,415	\$2,369.06	\$25.96	114	4.40
327120	Clay & nonclay refractories	30,546	\$6,212.96	\$54.94	270	4.92
327992	Minerals & earths, ground or otherwise treated	6,649	\$3,131.06	\$206.58	439	2.12
327000 [327999]	Other stone, clay, glass & concrete products [EPA assumed = Other concrete products]	9,801	\$3,320.18	\$103.36	305	2.95
327910	Abrasives & abrasive products	14,202	\$4,535.35	\$6.26	20	3.13
21231	Crushed & broken stone	53,827	\$15,169.46	\$169.80	603	3.55
Subtotal =		125,440	\$34,738.07	\$566.90	1,750	3.09
Percentage of 2nd Tier employees affiliated with delivered cost to 1st Tier industries =					1.4%	
Notes: - Columns B, C, and D obtained from the 2007 Economic Census						

Attachment H Industries Affiliated with Fill Dirt Pits Mining and/or Beneficiating (NAICS 212399) Potentially Negatively Impacted by CCR Beneficial Use, and their Respective Jobs Ratios						
A		B	C	D	E (B * (D / C))	F (E / D)
NAICS	2nd Tier Industry	Paid Employees in 2nd Tier Industries	Sales Revenues at 2nd tier industries (millions of 2007\$)	Delivered Cost to 1st Tier Industries (millions of 2007\$)	Count of Paid Employees in 2nd Tier affiliated with 1st Tier Delivered Cost	Jobs Ratio per \$million
212390	Crude minerals received for preparation	10,388	\$3,819.59	\$11.38	31	2.72
333999	Purchased machinery installed, incl. mobile loading, transport/other equip.	51,057	\$11,448.25	\$61.40	274	4.46
325000 [3259]	Industrial chemicals (chemical reagents, acidizing mat, etc.) [EPA assumed = All other chemical product & preparation mfg]	84,388	\$39,388.58	\$10.00	21	2.14
325920	Explosive materials	6,532	\$1,745.03	\$3.45	13	3.74
331000 [33122]	Steel shapes & forms, excluding castings & forgings [EPA assumed = Rolling & drawing of purchased steel]	26,881	\$12,680.43	\$1.43	3	2.12
324110	Distillate grade #1, 2, 4, & light diesel fuel used as fuel plus #5 & 6 & heavy diesel fuel used as fuel	64,839	\$580,019.95	\$17.80	2	0.11
211110	Gas (natural, manufactured & mixed) as a fuel	150,443	\$255,104.85	\$17.42	10	0.59
Subtotal =		394,528	\$904,206.68	\$122.87	354	2.88
Percentage of 2nd Tier employees affiliated with delivered cost to 1st Tier industries =					0.1%	
Notes: - Columns B, C, and D obtained from the 2007 Economic Census						

Attachment I Industries Affiliated with Gypsum Product Manufacturing (NAICS 327420) Potentially Negatively Impacted by CCR Beneficial Use, and Their Respective Job Ratios						
A		B	C	D	E (B * (D / C))	F (E / D)
NAICS	2nd Tier Industry	Paid Employees in 2nd Tier Industries	Sales Revenues at 2nd tier industries (millions of 2007\$)	Delivered Cost to 1st Tier Industries (millions of 2007\$)	Count of Paid Employees in 2nd Tier affiliated with 1st Tier Delivered Cost	Jobs Ratio per \$million
322130	Paperboard liners	36,657	\$25,357.58	\$167.73	242	1.45
322224	Paper shipping sacks & multiwall bags	10,415	\$2,369.06	\$15.92	70	4.40
322299	Other paper & paperboard products	18,103	\$4,920.28	\$476.55	1753	3.68
327120	Clay & nonclay refractories	30,546	\$6,212.96		0	
327310	Cement clinker	17,833	\$10,511.36	\$21.75	37	1.70
327992	Minerals & earths, ground or otherwise treated	6,649	\$3,131.06	\$186.25	396	2.12
327000 [327999]	Other stone, clay, glass & concrete products [EPA assumed = Other concrete products]	9,801	\$3,320.18	\$201.65	595	2.95
327910	Abrasives & abrasive products	14,202	\$4,535.35		0	
21231	Crushed & broken stone (cement rock, limestone, etc.)	53,827	\$15,169.46	\$266.93	947	3.55
Subtotal =		198,033	\$75,527.30	\$1,336.78	4,041	3.02
Percentage of 2nd Tier employees affiliated with delivered cost to 1st Tier industries =					2.0%	
Notes: - Columns B, C, and D obtained from the 2007 Economic Census						

Attachment J Percentage of Present Value Costs & Present Value Benefits for the CCR Final Rule Which Are Estimated to Occur Between Alternative Time Intervals				
Discount rate	50:50 Split of 100-Year CCR RIA Timeline (2015-2114) 2015-2064 (50 years) vs 2065-2114 (50 years)		IPM Timeline (40 Years) 2015-2054 vs 2055-2114	
	Costs	Benefits ³	Costs	Benefits ³
Non-discounted ¹	30%/70%	38%/62%	21%/79%	28%/72%
3%	61%/39%	71%/29%	50%/50%	61%/39%
4.77% (IPM rate) ²	78%/22%	85%/15%	69%/31%	77%/23%
7%	88%/12%	93%/7%	82%/18%	88%/12%
Notes: ¹ CCR RIA cost model runs were not conducted for the non-discounted scenario. The numbers presented here were extrapolated from RIA model runs under a 3% discount rate, with post-modeling adjustments made to reflect non-discounting. Some electric utility plants may select different CCR management options under the CCR final rule in a non-discounted scenario compared to under a 3% discount rate, which would then not be reflected here. However, these differences are expected to be minor with respect to the percentage breakouts displayed. ² While a RIA cost model run was conducted for the IPM's 4.77% discount rate to prepare the RIA cost estimates for use as inputs to the separate IPM project for the CCR final rule, a separate analysis of benefits under the 4.77% discount rate was not developed. Correspondingly, the benefits estimates presented in this row reflect simulation of future electric utility plant decisions concerning CCR management under a 3% discount rate, with post-modeling adjustments made to reflect a 4.77% discount rate. Some plants may select different CCR management options in a scenario with a 4.77% discount rate as compared to under a 3% discount rate, which would then not be reflected in the benefits numbers presented in this row. However, these differences are expected to be minor with respect to the percentage breakouts displayed. ³ Benefits do not reflect monetized air benefits estimated in this Appendix. Instead benefits are scaled from those December 2014 CCR final rule RIA benefits which were calculated in part based on the economic analysis of EPA Office of Water's June 2013 "Steam Electric Power Generator Effluent Limitations Guidelines" (ELG) proposed rule. The components scaled from the ELG rule were determined in aggregate rather than on a future annual basis. As such, determining different time interval splits for these benefit categories was not possible. Therefore, the splits presented above include only the remaining monetized benefits categories in the CCR RIA: (1) avoided CCR impoundment structural failure benefits, (2) avoided CCR groundwater contamination benefits; and (3) future induced increase in annual CCR beneficial uses. Note that the benefit categories in the CCR RIA based on the EPA-OW ELG proposed rule economic analysis comprise approximately 2% to 3% of the total annualized benefits monetized in the CCR RIA.				

Additional notes about the cost estimates of the CCR final rule over time (as estimated in the December 2014 RIA):

- CCR landfill costs (undiscounted) generally increase up through 2090, and are approximately an order of magnitude higher in the 2070s than they are in the 2040s. This occurs because the majority of landfill costs occur when new landfills that include the required liners and leachate collection systems open, which does not occur until existing landfills reach 80 years of age. Meanwhile, "early" landfill compliance costs consist solely of the relatively low-cost dust controls, run-on/run-off controls, etc. Under a 7% discount rate, landfill costs hit their break-even (50% before and after) around 2047; under a 0% discount rate, this break-even year is 2087.
- CCR disposal impoundment costs (undiscounted) rapidly increase by an order of magnitude between 2015 and 2019, then double between 2019 and 2020. This is due to the costs incurred associated with addressing existing environmental contamination from current management in unlined units. This existing contamination prompts CCR management changes according to the timeline of the CCR final rule. Costs increase in out-years as additional unlined impoundments may leak, but the impact is not dramatic: there is only a factor of two increase between undiscounted costs in the 2040s and the 2080s. Under a 7% discount rate, disposal impoundment costs hit their break-even (50% before and after) around 2030; under a 0% discount rate, this break-even year is 2075.
- CCR storage impoundment costs follow a similar pattern to disposal impoundment costs: a rapid increase between 2015 and 2020, with relatively steady annual costs thereafter. (The costs are steadier because storage impoundments have fewer options for future configuration and management if they leak.) Under a 7% discount rate, storage impoundment costs hit their break-even (50% before and after) around 2028; under a 0% discount rate, this break-even year is 2068.

- Recordkeeping and reporting costs for the CCR final rule (2% to 5% of total costs, depending on discount rate) are largely annual and assumed to be the same every year. Inactive CCR impoundment costs (1% to 5% of total costs, depending on discount rate) occur only in the first 40 years of the time horizon.
- Combining all CCR management unit costs together, there are substantial cost increases (undiscounted) between 2015 and 2020, and then relatively steady, but increasing (due to landfills) costs for the remainder of the time horizon. Roughly 10% of the (undiscounted) costs are directly attributable to CCR management changes required by existing contamination at unlined impoundments, and approximately 35% of the costs are attributable to CCR management changes at unlined impoundments likely to leak during their operating lives that had not yet leaked as of 2020. At a 7% discount rate, these proportions increase to 60% and 75%, respectively. The overall breakeven years are 2031 (7% discount rate) and 2080 (0% discount rate).