807 KAR 5:058 Section 8(3)(e)(1) The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multistate integrated system shall submit the following information for its operations within Kentucky and for the multistate utility system of which it is a part. A utility which purchases fifty (50) percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases its energy needs. (e) For each existing and new conservation and load management or other demand-side programs included in the plan; (1) Targeted classes and end-uses.

The following tables provide the targeted classes and end-uses for the Existing and New DSM programs included in the plan. More detailed program descriptions can be found in Exhibits DSM-5 and DSM-6 in the Technical Appendix – Demand-Side Management.

Table 8.(3)(e)(1)-1
Existing Programs

Program Name	Class	End-uses
Button-Up Tiered Weatherization	Residential	Space Heating, Space Cooling
Heat Pump Retrofit	Residential	Space Heating, Space Cooling
Direct Load Control of AC & WH	Residential	Space Cooling, Water Heating
Residential Lighting	Residential	Lighting
Touchstone Energy (TSE) Home	Residential	Space Heating, Space Cooling, Water Heating
ENERGY STAR® Manufactured Home	Residential	Space Heating, Space Cooling
Tune-Up HVAC w/ Duct Sealing	Residential	Space Heating, Space Cooling
Low Income with Community Action	Residential	Space Heating, Space Cooling, Water Heating, Lighting
ENERGY STAR® Appliances	Residential	Dishwasher, Refrigerator, Freezer, Water Heating, Space Heating & Cooling, Clothes Washer.
Appliance Recycling	Residential	Refrigerator, Freezer
Commercial Lighting	Commercial	Lighting
Compressed Air	Industrial	Compressed Air
Large Interruptible	Industrial	Various
Other Interruptible	Industrial	Various

Table 8(3)(e)(1)-2
New Programs

Program Name	Class	End-uses
Consumer Electronics	Residential	Televisions, Desktop Computers, Top Boxes
Exterior Lighting	Residential	Lighting
Water Heater Conservation	Residential	Water Heating
Smart Thermostat	Residential	Space Heating, Space Cooling
Home Energy Information	Residential	Various
C&I Demand Response	Commercial, Industrial	Various
Industrial Process	Industrial	Process Loads
Industrial Machine Drive	Industrial	Drive Power
DLC for Commercial Central AC	Commercial	Space Cooling
C&I Equipment Rebate	Commercial	Space Cooling, Space Heating, Ventilation, Refrigeration, Water Heating
C&I New Construction	Commercial, Industrial	Space Cooling, Space Heating, Ventilation, Lighting

807 KAR 5:058 Section 8(3)(e)(2) The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multistate integrated system shall submit the following information for its operations within Kentucky and for the multistate utility system of which it is a part. A utility which purchases fifty (50) percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases its energy needs. (e) For each existing and new conservation and load management or other demand-side programs included in the plan; (2) Expected duration of the program.

Expected duration of the program;

The following tables provide the expected duration of the program. For each existing and new program, the number of years that new participants are served is given as well as the lifetime of the measure savings:

Table 8.(3)(e)(2)-1
Existing Programs – Duration

Program Name	New Participants	Savings Lifetime
Button-Up Tiered Weatherization	15 years	15 years
Heat Pump Retrofit	15 years	20 years
Direct Load Control of AC & WH	5 years	20 years
Residential Lighting	15 years	8 years
Touchstone Energy (TSE) Home	15 years	20 years
ENERGY STAR® Manufactured Home	5 years	15 years
Tune-Up HVAC w/ Duct Sealing	15 years	12 years
Low Income with Community Action	5 years	15 years
ENERGY STAR® Appliances	15 years	12-20 years
Appliance Recycling	15 years	7 years
Commercial Lighting	15 years	10 years
Compressed Air	5 years	7 years
Large Interruptible	NA	20 years
Other Interruptible	NA	20 years

Table 8.(3)(e)(2)-2
New Programs – Duration

Program Name	New Participants	Savings Lifetime
Consumer Electronics	12 years	6 years
Exterior Lighting	12 years	20 years
Water Heater Conservation	12 years	11 years
Smart Thermostat	12 years	15 years
Home Energy Information	12 years	3 years
C&I Demand Response	3 years	20 years
Industrial Process	15 years	10 years
Industrial Machine Drive	15 years	15 years
DLC for Commercial Central AC	5 years	20 years
C&I Equipment Rebate	15 years	10-15 years
C&I New Construction	15 years	20 years

807 KAR 5:058 Section 8(3)(e)(3) The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multistate integrated system shall submit the following information for its operations within Kentucky and for the multistate utility system of which it is a part. A utility which purchases fifty (50) percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases its energy needs. (e) For each existing and new conservation and load management or other demand-side programs included in the plan: (3) Projected energy changes by season, and summer and winter peak demand changes.

The following tables provide the projected annual energy, summer peak demand and winter peak demand changes for each Existing and New DSM program included in the plan. Load changes for the Existing programs have been accounted for in the Load Forecast. Load changes for New Programs are accounted for in the integrated resource plan. The load changes for Existing demand response programs reflect the effect of all participants, current and future. For all other programs, the load changes reflect the effect of future participants only.

Load Impacts of DSM Programs

Existing:

Button-Up Tiered Weatherization Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	1,109	-3,039	-2.4	-0.7
2016	2,268	-6,215	-4.8	-1.5
2017	3,427	-9,392	-7.3	-2.2
2018	4,586	-12,568	-9.7	-3.0
2019	5,745	-15,744	-12.2	-3.7
2020	8,405	-23,034	-17.8	-5.4
2021	11,015	-30,187	-23.3	-7.1
2022	13,589	-37,241	-28.8	-8.8
2023	16,130	-44,204	-34.2	-10.4
2024	18,656	-51,127	-39.5	-12.0
2025	21,182	-58,049	-44.9	-13.7
2026	23,708	-64,972	-50.2	-15.3
2027	26,234	-71,894	-55.6	-16.9
2028	28,760	-78,817	-61.0	-18.5
2029	31,286	-85,739	-66.3	-20.2

Residential Heat Pump Retrofit

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	618	-4,655	0.0	-0.2
2016	1,336	-10,063	0.0	-0.4
2017	2,054	-15,471	0.0	-0.7
2018	2,772	-20,879	0.0	-0.9
2019	3,490	-26,287	0.0	-1.1
2020	4,632	-34,888	0.0	-1.5
2021	5,907	-44,492	0.0	-1.9
2022	7,318	-55,119	0.0	-2.3
2023	8,863	-66,756	0.0	-2.8
2024	10,548	-79,448	0.0	-3.4
2025	12,233	-92,139	0.0	-3.9
2026	13,918	-104,830	0.0	-4.5
2027	15,603	-117,522	0.0	-5.0
2028	17,288	-130,213	0.0	-5.5
2029	18,973	-142,905	0.0	-6.1

Direct Load Control of Residential Air Conditioners and Water Heaters

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	40,000	-1,026	-7.7	-28.1
2016	47,500	-1,221	-9.0	-33.5
2017	55,000	-1,416	-10.4	-38.9
2018	62,500	-1,611	-11.7	-44.3
2019	70,000	-1,806	-13.1	-49.7
2020	70,000	-1,806	-13.1	-49.7
2021	70,000	-1,806	-13.1	-49.7
2022	70,000	-1,806	-13.1	-49.7
2023	70,000	-1,806	-13.1	-49.7
2024	70,000	-1,806	-13.1	-49.7
2025	70,000	-1,806	-13.1	-49.7
2026	70,000	-1,806	-13.1	-49.7
2027	70,000	-1,806	-13.1	-49.7
2028	70,000	-1,806	-13.1	-49.7
2029	70,000	-1,806	-13.1	-49.7

Residential Lighting Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	5,000	-1,088	-0.2	-0.1
2016	10,000	-2,176	-0.3	-0.2
2017	15,000	-3,264	-0.5	-0.4
2018	20,000	-4,352	-0.7	-0.5
2019	25,000	-5,440	-0.8	-0.6
2020	59,335	-12,911	-1.9	-1.4
2021	92,695	-20,170	-3.0	-2.2
2022	117,683	-25,608	-3.8	-2.8
2023	136,203	-29,638	-4.4	-3.3
2024	154,326	-33,581	-5.0	-3.7
2025	172,449	-37,525	-5.6	-4.1
2026	190,572	-41,468	-6.2	-4.6
2027	208,695	-45,412	-6.8	-5.0
2028	197,483	-42,972	-6.4	-4.7
2029	187,246	-40,745	-6.1	-4.5

Touchstone Energy New Construction Home

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	234	-571	-0.6	-0.1
2016	518	-1,264	-1.2	-0.3
2017	852	-2,079	-2.0	-0.5
2018	1,186	-2,894	-2.8	-0.7
2019	1,520	-3,710	-3.6	-1.0
2020	1,690	-4,125	-4.0	-1.1
2021	1,858	-4,535	-4.4	-1.2
2022	2,024	-4,940	-4.8	-1.3
2023	2,186	-5,335	-5.2	-1.4
2024	2,342	-5,716	-5.5	-1.5
2025	2,498	-6,096	-5.9	-1.6
2026	2,654	-6,477	-6.3	-1.7
2027	2,810	-6,858	-6.6	-1.8
2028	2,966	-7,239	-7.0	-1.9
2029	3,122	-7,619	-7.4	-2.0

ENERGY STAR® Manufactured Home Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	400	-4,779	-1.2	-0.2
2016	800	-9,558	-2.3	-0.4
2017	1,200	-14,336	-3.5	-0.6
2018	1,600	-19,115	-4.6	-0.8
2019	2,000	-23,894	-5.8	-1.0
2020	2,000	-23,894	-5.8	-1.0
2021	2,000	-23,894	-5.8	-1.0
2022	2,000	-23,894	-5.8	-1.0
2023	2,000	-23,894	-5.8	-1.0
2024	2,000	-23,894	-5.8	-1.0
2025	2,000	-23,894	-5.8	-1.0
2026	2,000	-23,894	-5.8	-1.0
2027	2,000	-23,894	-5.8	-1.0
2028	2,000	-23,894	-5.8	-1.0
2029	2,000	-23,894	-5.8	-1.0

Tune-Up HVAC with Duct Sealing Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	550	-457	-0.4	-0.1
2016	1,200	-996	-0.9	-0.3
2017	1,950	-1,619	-1.5	-0.5
2018	2,700	-2,242	-2.1	-0.6
2019	3,450	-2,865	-2.7	-0.8
2020	4,249	-3,528	-3.3	-1.0
2021	5,033	-4,179	-3.9	-1.2
2022	5,806	-4,821	-4.5	-1.4
2023	6,566	-5,452	-5.1	-1.6
2024	7,319	-6,078	-5.7	-1.7
2025	8,072	-6,703	-6.3	-1.9
2026	8,825	-7,328	-6.9	-2.1
2027	9,028	-7,497	-7.0	-2.1
2028	9,131	-7,582	-7.1	-2.2
2029	9,134	-7,585	-7.1	-2.2

Low Income with Community Action Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	250	-1,183	-0.4	-0.2
2016	550	-2,602	-0.8	-0.4
2017	900	-4,258	-1.3	-0.6
2018	1,250	-5,913	-1.8	-0.9
2019	1,600	-7,569	-2.3	-1.2
2020	1,600	-7,569	-2.3	-1.2
2021	1,600	-7,569	-2.3	-1.2
2022	1,600	-7,569	-2.3	-1.2
2023	1,600	-7,569	-2.3	-1.2
2024	1,600	-7,569	-2.3	-1.2
2025	1,600	-7,569	-2.3	-1.2
2026	1,600	-7,569	-2.3	-1.2
2027	1,600	-7,569	-2.3	-1.2
2028	1,600	-7,569	-2.3	-1.2
2029	1,600	-7,569	-2.3	-1.2

ENERGY STAR® Appliances Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	12,950	-5,634	-0.6	-2.1
2016	25,900	-11,268	-1.2	-4.1
2017	38,850	-16,902	-1.8	-6.2
2018	51,800	-22,536	-2.4	-8.2
2019	64,750	-28,170	-3.0	-10.3
2020	75,263	-31,484	-3.4	-11.0
2021	85,718	-34,834	-3.7	-11.8
2022	96,155	-38,234	-4.1	-12.6
2023	106,517	-41,671	-4.5	-13.4
2024	116,881	-45,166	-4.9	-14.2
2025	127,245	-48,662	-5.2	-15.0
2026	137,609	-52,157	-5.6	-15.8
2027	140,348	-54,463	-5.7	-16.5
2028	142,362	-55,174	-5.5	-17.0
2029	144,376	-55,886	-5.3	-17.6

Appliance Recycling Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	2,340	-1,044	-0.1	-0.1
2016	4,680	-2,088	-0.2	-0.3
2017	7,020	-3,131	-0.3	-0.4
2018	9,360	-4,175	-0.4	-0.6
2019	11,700	-5,219	-0.5	-0.7
2020	18,973	-8,463	-0.8	-1.2
2021	26,107	-11,646	-1.2	-1.7
2022	30,802	-13,740	-1.4	-2.0
2023	35,410	-15,796	-1.6	-2.3
2024	39,976	-17,832	-1.8	-2.6
2025	44,542	-19,869	-2.0	-2.9
2026	49,108	-21,906	-2.2	-3.1
2027	48,741	-21,742	-2.2	-3.1
2028	48,513	-21,641	-2.2	-3.1
2029	48,384	-21,583	-2.2	-3.1

Commercial Lighting Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	1,071	-3,647	-0.4	-0.7
2016	1,964	-6,688	-0.7	-1.3
2017	3,679	-12,528	-1.3	-2.5
2018	6,274	-21,366	-2.3	-4.3
2019	9,451	-32,184	-3.4	-6.4
2020	13,462	-45,844	-4.9	-9.2
2021	17,303	-58,924	-6.3	-11.8
2022	21,153	-72,035	-7.7	-14.4
2023	25,032	-85,244	-9.1	-17.0
2024	28,947	-98,576	-10.5	-19.7
2025	31,791	-108,261	-11.5	-21.6
2026	34,813	-118,552	-12.6	-23.7
2027	37,013	-126,044	-13.4	-25.2
2028	38,333	-130,539	-13.9	-26.1
2029	39,071	-133,053	-14.2	-26.6

Compressed Air Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	250	-855	-0.1	-0.2
2016	875	-2,992	-0.2	-0.6
2017	2,125	-7,266	-0.6	-1.4
2018	3,375	-11,540	-0.9	-2.3
2019	4,625	-15,815	-1.2	-3.1
2020	4,625	-15,815	-1.2	-3.1
2021	4,625	-15,815	-1.2	-3.1
2022	4,375	-14,960	-1.2	-3.0
2023	3,750	-12,823	-1.0	-2.5
2024	2,500	-8,548	-0.7	-1.7
2025	1,250	-4,274	-0.3	-0.8
2026	-	0	0.0	0.0
2027	-	0	0.0	0.0
2028	-	0	0.0	0.0
2029	-	0	0.0	0.0

Large Interruptible

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	1	-30,600	-85.0	-85.0
2016	1	-30,600	-85.0	-85.0
2017	1	-30,600	-85.0	-85.0
2018	1	-30,600	-85.0	-85.0
2019	1	-30,600	-85.0	-85.0
2020	1	-30,600	-85.0	-85.0
2021	1	-30,600	-85.0	-85.0
2022	1	-30,600	-85.0	-85.0
2023	1	-30,600	-85.0	-85.0
2024	1	-30,600	-85.0	-85.0
2025	1	-30,600	-85.0	-85.0
2026	1	-30,600	-85.0	-85.0
2027	1	-30,600	-85.0	-85.0
2028	1	-30,600	-85.0	-85.0
2029	1	-30,600	-85.0	-85.0

Other Interruptible Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	7	-8,640	-24.0	-24.0
2016	7	-8,640	-24.0	-24.0
2017	7	-8,640	-24.0	-24.0
2018	7	-8,640	-24.0	-24.0
2019	7	-8,640	-24.0	-24.0
2020	7	-8,640	-24.0	-24.0
2021	7	-8,640	-24.0	-24.0
2022	7	-8,640	-24.0	-24.0
2023	7	-8,640	-24.0	-24.0
2024	7	-8,640	-24.0	-24.0
2025	7	-8,640	-24.0	-24.0
2026	7	-8,640	-24.0	-24.0
2027	7	-8,640	-24.0	-24.0
2028	7	-8,640	-24.0	-24.0
2029	7	-8,640	-24.0	-24.0

New:

Consumer Electronics Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	-	0	0.0	0.0
2016	-	0	0.0	0.0
2017	-	0	0.0	0.0
2018	65,969	-3,810	-0.3	-0.6
2019	150,656	-8,700	-0.7	-1.4
2020	254,107	-14,675	-1.1	-2.3
2021	355,732	-20,544	-1.6	-3.2
2022	455,975	-26,333	-2.1	-4.1
2023	554,618	-32,029	-2.5	-5.0
2024	586,432	-33,866	-2.6	-5.3
2025	599,528	-34,623	-2.7	-5.4
2026	593,860	-34,295	-2.7	-5.3
2027	590,018	-34,074	-2.7	-5.3
2028	587,558	-33,931	-2.6	-5.3
2029	586,698	-33,882	-2.6	-5.3

Residential Exterior Lighting Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	-	0	0.0	0.0
2016	-	0	0.0	0.0
2017	-	0	0.0	0.0
2018	28,409	-2,267	-0.5	0.0
2019	64,845	-5,175	-1.2	0.0
2020	109,808	-8,763	-2.1	0.0
2021	154,527	-12,331	-2.9	0.0
2022	169,508	-13,527	-3.2	0.0
2023	172,970	-13,803	-3.3	0.0
2024	176,394	-14,076	-3.4	0.0
2025	179,818	-14,349	-3.4	0.0
2026	183,242	-14,623	-3.5	0.0
2027	186,666	-14,896	-3.5	0.0
2028	190,090	-15,169	-3.6	0.0
2029	193,514	-15,442	-3.7	0.0

Residential Water Heater Conservation program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	-	0	0.0	0.0
2016	-	0	0.0	0.0
2017	-	0	0.0	0.0
2018	2,987	-1,646	-0.4	-0.1
2019	6,736	-3,712	-0.9	-0.3
2020	11,286	-6,219	-1.5	-0.5
2021	15,773	-8,691	-2.1	-0.6
2022	20,203	-11,132	-2.6	-0.8
2023	24,520	-13,511	-3.2	-1.0
2024	28,766	-15,850	-3.7	-1.2
2025	33,012	-18,190	-4.3	-1.3
2026	37,258	-20,529	-4.8	-1.5
2027	41,504	-22,869	-5.4	-1.7
2028	45,750	-25,208	-5.9	-1.8
2029	47,009	-25,902	-6.1	-1.9

Residential Smart Thermostat Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	-	0	0.0	0.0
2016	-	0	0.0	0.0
2017	-	0	0.0	0.0
2018	4,147	-3,363	-2.6	-0.8
2019	10,223	-8,291	-6.4	-1.9
2020	17,667	-14,328	-11.1	-3.4
2021	24,968	-20,249	-15.7	-4.7
2022	32,161	-26,083	-20.3	-6.1
2023	39,258	-31,838	-24.7	-7.5
2024	46,302	-37,551	-29.2	-8.8
2025	53,346	-43,264	-33.6	-10.1
2026	60,390	-48,976	-38.0	-11.5
2027	67,434	-54,689	-42.5	-12.8
2028	74,478	-60,402	-46.9	-14.2
2029	81,522	-66,114	-51.4	-15.5

Home Energy Information Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	-	0	0.0	0.0
2016	-	0	0.0	0.0
2017	-	0	0.0	0.0
2018	22,901	-15,023	-5.5	-3.2
2019	56,341	-36,960	-13.5	-7.9
2020	97,278	-63,814	-23.3	-13.6
2021	114,537	-75,136	-27.5	-16.0
2022	120,700	-79,179	-29.0	-16.9
2023	118,866	-77,976	-28.5	-16.6
2024	117,571	-77,127	-28.2	-16.5
2025	116,833	-76,642	-28.0	-16.4
2026	116,595	-76,486	-28.0	-16.3
2027	116,595	-76,486	-28.0	-16.3
2028	116,595	-76,486	-28.0	-16.3
2029	116,595	-76,486	-28.0	-16.3

Commercial & Industrial Demand Response Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	150	-1,575	-5.5	-5.5
2016	350	-3,675	-12.8	-12.8
2017	500	-5,250	-18.2	-18.2
2018	500	-5,250	-18.2	-18.2
2019	500	-5,250	-18.2	-18.2
2020	500	-5,250	-18.2	-18.2
2021	500	-5,250	-18.2	-18.2
2022	500	-5,250	-18.2	-18.2
2023	500	-5,250	-18.2	-18.2
2024	500	-5,250	-18.2	-18.2
2025	500	-5,250	-18.2	-18.2
2026	500	-5,250	-18.2	-18.2
2027	500	-5,250	-18.2	-18.2
2028	500	-5,250	-18.2	-18.2
2029	500	-5,250	-18.2	-18.2

Industrial Process Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	20	-517	0.0	-0.1
2016	48	-1,240	-0.1	-0.2
2017	88	-2,274	-0.2	-0.4
2018	148	-3,824	-0.3	-0.8
2019	228	-5,892	-0.5	-1.2
2020	328	-8,476	-0.7	-1.7
2021	428	-11,060	-0.9	-2.2
2022	528	-13,644	-1.1	-2.7
2023	628	-16,228	-1.3	-3.2
2024	728	-18,812	-1.5	-3.7
2025	808	-20,879	-1.6	-4.1
2026	880	-22,739	-1.8	-4.5
2027	940	-24,290	-1.9	-4.8
2028	980	-25,323	-2.0	-5.0
2029	1,000	-25,840	-2.0	-5.1

Industrial Machine Drive program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	17	-1,505	-0.1	-0.2
2016	31	-2,745	-0.2	-0.3
2017	37	-3,277	-0.3	-0.4
2018	70	-6,199	-0.5	-0.7
2019	130	-11,513	-0.9	-1.2
2020	265	-23,468	-1.8	-2.5
2021	400	-35,423	-2.8	-3.8
2022	535	-47,379	-3.7	-5.1
2023	670	-59,334	-4.6	-6.4
2024	805	-71,289	-5.6	-7.7
2025	940	-83,245	-6.5	-9.0
2026	1,075	-95,200	-7.4	-10.3
2027	1,210	-107,155	-8.4	-11.5
2028	1,345	-119,111	-9.3	-12.8
2029	1,480	-131,066	-10.3	-14.1

DLC for Commercial Central Air Conditioners

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	1,200	-138	0.0	-2.4
2016	2,400	-276	0.0	-4.8
2017	3,600	-415	0.0	-7.2
2018	4,800	-553	0.0	-9.6
2019	6,000	-691	0.0	-12.0
2020	6,000	-691	0.0	-12.0
2021	6,000	-691	0.0	-12.0
2022	6,000	-691	0.0	-12.0
2023	6,000	-691	0.0	-12.0
2024	6,000	-691	0.0	-12.0
2025	6,000	-691	0.0	-12.0
2026	6,000	-691	0.0	-12.0
2027	6,000	-691	0.0	-12.0
2028	6,000	-691	0.0	-12.0
2029	6,000	-691	0.0	-12.0

Commercial & Industrial Equipment Rebate program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	641	-1,602	-0.2	-0.4
2016	1,980	-4,889	-0.5	-1.2
2017	4,211	-10,332	-1.2	-2.6
2018	7,577	-18,547	-2.2	-4.6
2019	10,873	-26,714	-3.1	-6.6
2020	15,027	-37,020	-4.2	-9.2
2021	18,439	-45,581	-5.1	-11.3
2022	21,874	-54,203	-6.0	-13.4
2023	25,334	-62,898	-6.9	-15.5
2024	28,824	-71,674	-7.8	-17.6
2025	32,247	-79,887	-8.7	-19.7
2026	35,634	-87,813	-9.5	-21.7
2027	38,970	-95,333	-10.3	-23.6
2028	42,226	-102,199	-11.0	-25.5
2029	45,418	-108,492	-11.7	-27.2

Commercial & Industrial New Construction program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	132	-1,663	-0.2	-0.4
2016	264	-3,326	-0.5	-0.9
2017	396	-4,989	-0.7	-1.3
2018	528	-6,652	-0.9	-1.7
2019	660	-8,315	-1.1	-2.2
2020	792	-9,978	-1.4	-2.6
2021	924	-11,641	-1.6	-3.0
2022	1,056	-13,304	-1.8	-3.4
2023	1,188	-14,967	-2.0	-3.9
2024	1,320	-16,630	-2.3	-4.3
2025	1,452	-18,293	-2.5	-4.7
2026	1,584	-19,956	-2.7	-5.2
2027	1,716	-21,619	-2.9	-5.6
2028	1,848	-23,281	-3.2	-6.0
2029	1,980	-24,944	-3.4	-6.5

807 KAR 5:058 Section 8(3)(e)(4) For each existing and new conservation and load management or other demand-side programs included in the plan; (4) Projected cost, including any incentive payments and program administrative costs.

The projected costs for each Existing and New DSM program are shown below in Table 8.(3)(e)(4). Cost values are the present value of the future stream of costs for that element. Distribution system rebates are paid to program participants. More details on program costs and cost-effectiveness can be found in the Technical Appendix – Demand-Side Management.

Table 8.(3)(e)(4)
Existing and New DSM Program Costs

EXISTING Program	Program costs Distribution System Admin	present value, 2015 $ EKPC Admin	Distribution System Rebates	Customer Investment
Button-Up Tiered Weatherization	$10,364,324	$1,071,760	$16,788,862	$48,351,921
Heat Pump Retrofit	$2,373,686	$564,084	$10,057,992	$61,689,020
Direct Load Control of AC & WH	$0	$23,034,823	$7,187,731	$0
Residential Lighting	$0	$1,565,037	$5,149,930	$8,239,887
Touchstone Energy (TSE) Home	$1,058,719	$676,901	$1,846,603	$4,561,110
ENERGY STAR® Manufactured Home	$0	$3,543,907	$0	$0
Tune-Up HVAC w/ Duct Sealing	$826,628	$67,690	$2,314,558	$2,182,298
Low Income with Community Action	$2,577,506	$91,899	$0	$2,288,358
ENERGY STAR® Appliances	$0	$2,471,852	$19,028,599	$41,925,626
Appliance Recycling	$0	$5,119,250	$2,876,378	$0
Commercial Lighting	$0	$1,336,292	$7,365,022	$40,614,258
Compressed Air	$331,607	$149,336	$0	$3,059,076
Totals	$17,532,470	$39,692,831	$72,615,676	$212,911,554

NEW Program	Program costs Distribution System Admin	present value, 2015 $ EKPC Admin	Distribution System Rebates	Customer Investment
Consumer Electronics	$0	$630,499	$15,860,395	$8,475,399
Exterior Lighting	$0	$560,978	$1,524,256	$2,534,076
Water Heater Conservation	$0	$2,249,589	$0	$0
Smart Thermostat	$0	$748,848	$10,739,803	$14,074,795
Home Energy Information	$16,569,036	$2,244,207	$0	$17,133,521
C&I Demand Response	$0	$4,154,416	$7,125,100	$5,434,663
Industrial Process	$0	$1,843,762	$1,482,748	$8,377,526
Industrial Machine Drive	$0	$1,300,139	$5,090,483	$21,532,741
DLC for Commercial Central AC	$0	$3,287,627	$3,018,604	$0
C&I Equipment Rebate	$4,917,272	$3,282,876	$12,921,387	$23,073,363
C&I New Construction	$0	$746,847	$3,350,659	$6,031,186
Totals	$21,486,308	$21,049,786	$61,113,436	$106,667,271

807 KAR 5:058 Section 8(3)(e)(5) For each existing and new conservation and load management or other demand-side programs included in the plan; (5) Projected cost savings, including savings in utility's generation, transmission and distribution costs.

The projected cost savings for each Existing and New DSM program are shown below in Table 8.(3)(e)(5). Values shown are the benefits in the Total Resource Cost test. Cost values are the present value of the future stream of costs for that element. More details on program costs and cost-effectiveness can be found in the Technical Appendix – Demand-Side Management.

Table 8.(3)(e)(5)
Existing and New DSM Program Cost Savings

		present value, 2015 $
EXISTNG Program		**Projected Cost Savings**
Button-Up Tiered Weatherization		$68,545,735
Heat Pump Retrofit		$86,653,963
Direct Load Control of AC & WH		$52,729,759
Residential Lighting		$20,923,323
Touchstone Energy (TSE) Home		$8,571,894
ENERGY STAR® Manufactured Home		$15,128,932
Tune-Up HVAC w/ Duct Sealing		$6,921,241
Low Income with Community Action*		$6,662,855
ENERGY STAR® Appliances		$60,535,394
Appliance Recycling		$11,823,262
Commercial Lighting		$81,156,428
Compressed Air		$6,520,793
Totals		$426,173,579

*When modeling the Existing DSM Program Cost Savings, EKPC expected to file the Low Income with Community Action tariff before publishing this IRP. Due to unforeseen circumstances, EKPC is filing the Low Income with Community Action tariff contemporaneously with the IRP. However, the Existing Program Cost Savings were modeled to include the Low Income with Community Action program.

NEW Program		present value, 2015 $ Projected Cost Savings
Consumer Electronics		$18,876,954
Exterior Lighting		$9,480,809
Water Heater Conservation		$11,179,919
Smart Thermostat		$51,555,650
Home Energy Information		$50,667,694
C&I Demand Response		$42,142,820
Industrial Process		$14,656,815
Industrial Machine Drive		$67,891,628
DLC for Commercial Central AC		$23,211,331
C&I Equipment Rebate		$79,357,637
C&I New Construction		$24,211,759
Totals		$393,233,018

807 KAR 5:058 Section 8(5)(c) Criteria (for example, present value of revenue requirements, capital requirements, environmental impacts, flexibility, diversity) used to screen each resource alternative including demand-side programs, and criteria used to select the final mix of resources presented in the acquisition plan.

Please see pages 7 through 10 in the Technical Appendix –Volume 2 - Demand-Side Management.

All DSM programs are evaluated based on the standard California tests.

SECTION 6.0

TRANSMISSION AND DISTRIBUTION PLANNING

SECTION 6.0

TRANSMISSION AND DISTRIBUTION PLANNING

6.1 Introduction

807 KAR 5:058 Section 8(2)(a) The utility shall describe and discuss all options considered for inclusion in the plan including: (a) Improvements to and more efficient utilization of existing utility generation, transmission, and distribution facilities;

Transmission System

Introduction

EKPC's transmission system is geographically located in roughly the eastern two-thirds of Kentucky. The transmission system approaches the borders of Kentucky in the north, east, and south, and stretches to approximately the Interstate 65 corridor in the west. The system is comprised of approximately 2,938 circuit miles of line at voltages of 69, 138, 161, and 345 kV, and includes 73 free-flowing interconnections with neighboring utilities.

EKPC designs its transmission system to provide adequate capacity for reliable delivery of EKPC generating resources to its member distribution cooperatives, and for long-term firm transmission service that has been reserved on the EKPC system. EKPC's transmission planning criteria specify that the system must be designed to meet projected customer demands for simultaneous outages of a transmission facility and a generating unit during peak conditions in summer and winter.

Interconnections

EKPC's interconnections with neighboring utilities have been established to improve the reliability of the transmission system and to provide access to external generation resources for economic and/or emergency purchases. Table 8.(2)(a)-1 (page 130) through Table 8.(2)(a)-2 (page 131) list each of EKPC's free-flowing interconnections. The interconnections established with other utilities generally have provided stronger sources in specific areas of need within the EKPC system. This avoids the need to construct long, high-voltage transmission lines from the EKPC system and typically reduces EKPC's transmission-system losses.

EKPC participates in joint planning efforts with neighboring utilities to ascertain the benefits of potential interconnections, which can include increased power transfer capability, local area system support, and outlet capability for new generation. It should be noted that actual transfer capabilities are unique to real-time system conditions, as affected by generation dispatch, outage conditions, load level, third-party transfers, etc.

EKPC has established two new interconnections (both with LG&E/KU) since the last Integrated Resource Plan was completed. These two new interconnections are Goldbug-Wofford 69 kV and South Anderson-Bonds Mill 69 kV. Both of these interconnections provide needed system support to the electric system in those areas, but have minimal power transfer benefits. EKPC is planning a new 69 kV interconnection with Duke Energy Ohio-Kentucky at the Hebron substation in June 2015. This new interconnection is needed to improve the reliability of the electric system in the area, and again has minimal power transfer benefits.

Membership in PJM Interconnection, LLC. ("PJM")

EKPC integrated into PJM on June 1, 2013. PJM is a Regional Transmission Organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. Acting as a neutral, independent party, PJM operates a competitive wholesale electricity market and manages the high-voltage electricity grid to ensure reliability. PJM manages the high-voltage electricity grid to ensure reliability for more than 61 million people. PJM's long-term regional planning process provides a broad, interstate perspective that identifies the most effective and cost-efficient improvements to the grid to ensure reliability and economic benefits on a system wide basis. PJM is registered in the SERC region as the following reliability functions as described in the NERC Reliability Functional Model for PJM Members: Balancing Authority (BA), Interchange Authority (IA), Planning Coordinator (PC), Reliability Coordinator (RC), Resource Planner (RP), Transmission Operator (TOP), Transmission Planner (TP), and the Transmission Service Provider (TSP).

Membership in SERC Reliability Corporation ("SERC")

EKPC is a member of SERC. From the SERC website (www.serc1.org), SERC is "the regional entity responsible for promoting, coordinating and ensuring the reliability and adequacy of the bulk power supply systems in the area served by the Member Systems. SERC promotes the development of reliability and adequacy arrangements among the systems; participates in the establishment of reliability standards; administers a regional compliance and enforcement program; and provides a mechanism to resolve disputes on reliability issues." Owners, operators, and users of the bulk power system in the SERC footprint cover an area of approximately 560,000 square miles. SERC is one of eight regional entities with delegated authority from the North American Electric Reliability Corporation ("NERC"); the regional entities and all members of NERC work to safeguard the reliability of the bulk power systems throughout North America. NERC has been certified by the Federal Energy Regulatory Commission ("FERC") as the Electric Reliability Organization ("ERO") for North America. NERC has established Reliability Standards that the electric utilities operating in North America must adhere to. There are presently 98 Reliability Standards that have been approved by FERC and are therefore in effect. EKPC is required to comply with 43 of these standards based upon its responsibility for various functions. PJM is responsible for 38 of these standards on EKPC's behalf based on PJM's registration as the Balancing Authority, Resource Planner, Transmission Operator, etc. PJM and EKPC have joint compliance responsibilities for 16 reliability standards. Many additional standards are currently under development, and the development of new standards is certain to continue. PJM and EKPC continue to identify and refine planning practices that will ensure compliance with these NERC Reliability Standards.

EKPC actively participates in SERC activities and studies. Each year, EKPC participates in SERC assessments of transmission system performance for the summer and winter peak load periods. In these assessments, potential operating problems on the interconnected bulk transmission system are identified. EKPC annually supplies SERC with data needed for development of current and future load flow computer models. These models are used by EKPC and other SERC members to analyze and screen the interconnected transmission system for potential problems.

EKPC adheres to SERC's guidelines for transmission and generation planning and operations. With all of the SERC members following these guidelines, each member system can have a high degree of confidence that the transmission system will be adequate for the normal and emergency (outage) conditions simulated. Participation in SERC enhances the reliability of each member system without having to install excess generation and transmission capacity to provide a comparable level of reliability.

Transmission Expansion (2012-2014)

From 2012-2014, EKPC implemented various transmission projects, summarized as follows:

- Thirteen (13) transmission station modifications
  - Three (3) breaker replacements at 345 kV
  - Two (2) circuit switcher replacements at 161 kV
  - One (1) circuit switcher replacement at 138 kV
  - One (1) breaker addition at 138 kV
  - Three (3) breaker additions at 69 kV
  - Two (2) station rebuilds
  - One (1) 69 kV station upgrade
- Construction of 42 miles of new transmission lines
  - 41.9 miles – 69kV
  - 0.10 miles – 138kV
- Construction of two (2) 69 kV Switching stations
- Re-conductoring/rebuilding 25 miles of existing line using larger (lower impedance, higher capacity) conductor
- Addition of three (3) new 69 kV capacitor banks totaling 57.1 MVAR

Construction of the new transmission lines within the EKPC system generally has resulted in reduction of system losses.

EKPC upgraded existing transmission-line conductors in an effort to increase the capacity of the transmission system. EKPC's re-conductor projects typically increase line capacity by 50% to 225%, depending on the sizes of the installed conductor and the replacement conductor that is used. In addition, by installing larger conductors, less voltage drop is seen on the system, deferring the need to construct new facilities to provide voltage support in an area.

Transmission-system losses are also reduced due to the lower impedance of the larger replacement conductors. The amount of loss reduction varies, and is dependent on the hourly power flows on each particular line.

The addition of transmission capacitor banks provides better utilization of the existing transmission system by deferring the need for new transmission lines and/or substations through local reactive power and voltage support. Transmission capacitor banks can also provide some transmission-system loss reductions when energized.

Future Transmission Expansion

Transmission constraints, and the ability to address them in a timely manner, represent important planning considerations for ensuring that peak-load requirements are met reliably. EKPC's Transmission Planning Department works closely with other groups at EKPC -- such as Power Delivery Operations, Power Delivery Design & Construction, Power Delivery Maintenance, and Power Supply -- to coordinate activities and address reliability issues.

EKPC's transmission expansion plan includes a combination of new transmission lines and substation facilities and upgrades of existing facilities during the period from 2015 to 2033 to provide an adequate and reliable system for existing and forecasted native load customers and existing and future generation resources.

Transmission expansion plans are developed and updated on an annual basis. Power-flow analysis and reliability indices are used to predict problem areas on the transmission system. Various alternatives for mitigating these problems are then formulated and analyzed. The transmission expansion projects that provide the desired level of reliability and adequacy at a reasonable cost are then added into the plan. Note that transmission planning, like all EKPC planning processes, is ongoing, and changing conditions may warrant changes to the transmission plan.

EKPC's transmission work plan for the period from 2015 to 2019 is based on detailed engineering analyses, and includes transmission projects that are relatively firm in nature. These projects include the construction of new substations and transmission lines, as well as upgrades of existing substations and transmission lines. These improvements will meet growing customer demand, enhance system reliability, and improve the efficiency of the system. Maps of EKPC's existing transmission system and of the EKPC transmission system showing interconnected facilities plus EKPC's planned future facilities from 2015 to 2019 is included on the map in Section 11 of this report.

The planned improvements to the EKPC transmission system for the period from 2015 to 2019 are summarized as follows:

- Construction of approximately 13 miles of new 69 kV line
- High-temperature upgrades of thirty-three (33) 69-kV lines (151 miles total)
- High-temperature upgrades of three (3) 138-kV lines (21 miles total)
- Installation of one (1) new 161 kV capacitor bank (81.6 MVAR) and two (2) new 69-kV capacitor banks (32.6 MVARs total)
- Upgrade (size increase) of one (1) 69-kV capacitor bank from 10.8 MVARs to 20.4 MVARs
- Status change of a 69-kV line from normally open to normally closed
- Installation of two (2) 69-kV circuit breakers in preparation for a new 69-kV interconnection
- Re-conductor/rebuild of approximately 38 miles of 69 kV line

High-temperature upgrades increase the design operating temperature of a line facility without pursuing the more expensive option of line conductor replacement; the cost of high temperature upgrades is approximately 10% of the cost of conductor replacement for the same line facility. Although the relative cost makes a high-temperature upgrade an attractive option, these upgrades are not always possible. Also they provide no benefit to system voltages or system losses, and the increase in line capacity is typically much less than that provided by line conductor replacement.

Line terminal facility upgrades increase the effective thermal capacity of an existing line to meet system needs while eliminating the more expensive option of building a new line.

As previously mentioned, the addition of transmission capacitor banks will provide better utilization of the existing transmission system by deferring the need for new transmission lines and/or substations and can also provide some transmission system loss reductions when energized.

Increasing the size of an existing capacitor bank, where the magnitudes of voltage rise due to capacitor switching are within specified limits, is a better alternative than installation of a new capacitor bank. This is due to a more efficient utilization of substation space and greater transmission system loss reduction where the capacitor location is optimal.

The analysis used to develop the plan beyond the first four years is not necessarily less detailed than that used to develop the work plan for the first four years, but the assumed system conditions are less certain than those used for the first four years of analysis. Many of the projects beyond the first four-year period are conceptual in nature, and are more likely to change in scope and date, or to be cancelled and replaced with a different project. EKPC's 15-year expansion plan for the 2015-2030 period is included as Table 8.(2)(a)-3 on page 133 through Table 8.(2)(a)-12 on page 140. This 15-year expansion plan includes approximately 25 miles of new 69 kV line construction, 79 miles of existing line re-conductors/rebuilds, 191 miles of high-temperature conductor upgrades, and terminal facility upgrades associated with eleven (11) lines. It also includes one (1) transmission substation upgrade and the installation of a total of 292.4 MVARs of new transmission capacitor bank capability.

The inherent advantages of high-temperature upgrades of existing lines, upgrades of power transformers, and the addition of transmission capacitor banks are mentioned above.

As previously mentioned, construction of new transmission lines generally results in reduction of system losses. EKPC expects to see a net overall reduction in system losses as a result of the planned construction of 25 miles of new 69 kV lines in the 2015-2030 period.

The planned transmission line re-conductors/rebuilds will enhance utilization of the existing transmission system by increasing the capacity of those lines. As discussed earlier, replacing existing conductors with larger conductors will also provide increased voltage support and will reduce system energy losses. Similarly, the planned upgrades of power transformers will provide more efficient system utilization by increasing capacity while reducing voltage drop and system energy losses.

Line terminal facility upgrades increase the effective thermal capacity of a transmission line to meet system needs while eliminating the need for a new line.

Generation Related Transmission

When evaluating potential power supply resources, the cost of required transmission-system modifications associated with each resource is included in the analysis, if known. Some resource alternatives may be site-specific and transmission plans can be developed that are directly relevant for those resource alternatives. Other resource alternatives are generic units for which no specific site has been yet identified. For those generic units, an average cost of transmission is used in the cost analysis.

PJM and EKPC perform studies for transmission requirements for units connected to the EKPC transmission system after an official request has been submitted per PJM requirements. Only those projects necessary for firm (committed) generation resources (existing and future) are identified in EKPC's transmission expansion plan. No future generation resources are currently identified for connection to the EKPC system at a known location.

EKPC's generation expansion plan included in this Integrated Resource Plan does not identify new generation additions during the planning period. Therefore, no assumptions regarding transmission facilities needed for future generation expansion within the EKPC system have been made for this Integrated Resource Plan.

Import Capability

EKPC routinely assesses the ability to import power from external sources into the EKPC control area. Import capability is assessed from markets to the north and to the south as part of the normal planning process. Also, EKPC performs import capability studies as a participant in SERC's annual system assessments.

EKPC designs its transmission system to be capable of importing at least 500 MW from regions either north or south of Kentucky. Import studies indicate that EKPC's import capability from the LG&E/KU interface ranges from 750 MW up to 1000+ MW, depending on the time period being evaluated. EKPC imported up to 1425 MW in 2014 from its PJM interface, indicating that the import capability is in that range, even during winter peak conditions. Finally, the import capability from the TVA interface ranges from 850 MW up to 1000+ MW, depending on the time period. The imports from TVA are limited at certain times by facilities internal to the TVA system.

Although these import studies indicate that EKPC can during many periods import large quantities of power, real-time market and transmission-system conditions may result in system limitations that are significantly different from those predicted in these studies. Available Transfer Capacity ("ATC") calculations are performed by Regional Transmission Organizations (such as PJM and MISO), Independent Transmission Organizations (such as the LG&E/KU ITO) and Reliability Coordinators (such as TVA). These results are coordinated to ensure that the lowest value for a particular path is set as the ATC. Such studies utilize updated data for transmission and generation outages, market transactions, and system load to predict expected system flows. Therefore, it is difficult to predict the availability of transmission capacity for imports into the EKPC system. EKPC's membership in PJM ensures an adequate amount of transmission from the PJM market for import capability. EKPC may pursue to procure additional amounts of transmission from other supply sources in advance of peak seasons to ensure adequate import capability.

EKPC does not typically experience import and export transmission limitations on an operational basis due to limited ATC. EKPC's membership in PJM is one of the primary reasons for the elimination of historical constraints on imports and exports.

Extreme Weather Performance

EKPC annually performs an assessment of its transmission system for both summer and winter peak conditions. EKPC evaluates its system using two load forecasts – a 50/50 probability forecast and a 10/90 probability forecast. When evaluating system performance using a 50/50 forecast, contingency analysis is also performed on the system to ensure that the system is designed to provide adequate service at this load level even with a transmission facility and/or generator out of service. EKPC does not perform a contingency analysis when using the 10/90 probability forecast. EKPC considers an extreme weather event equivalent to a contingency, and therefore does not design its system for a transmission or generator outage in conjunction with this weather event, although EKPC does evaluate higher load scenarios to determine if there will be local reliability issues.

EKPC has identified two thermal constraints on its transmission system due to extreme weather conditions during the summer period; none were identified for the winter period. The following projects were identified to address thermal constraints during the summer period:

- Upgrade the 750 MCM copper bus at Dale station associated with the JK Smith-Dale 138 KV line using 1-inch IPS or equivalent equipment (In Service Date ("ISD"): 6/2026)
- Upgrade the 750 MCM jumper associated with the Summer Shade 161-69 KV transformer using 954 MCM ACSR or larger conductor (ISD: 6/2029).

No voltage limitations are anticipated for either the summer or winter periods provided that all transmission and generation facilities are in service. The outage of one or more facilities could result in thermal overloads and/or voltage limitations on the EKPC transmission system during extreme weather conditions.

Distribution System

EKPC is an all-requirements power supplier for 16 member-system distribution cooperatives in Kentucky. In addition to designing, owning, operating, and maintaining all transmission facilities, EKPC is responsible for all delivery points (distribution substations), including the planning of these delivery points in conjunction with the respective member systems. EKPC monitors peak distribution substation transformer loads seasonally to identify potential loading issues for delivery points to member systems. Furthermore, EKPC and the member systems jointly develop load forecasts for each delivery point that are used to identify future loading issues. EKPC typically uses a four-year planning horizon for distribution substation planning. EKPC and the member systems use a joint planning philosophy based on a "one-system" concept. This planning approach identifies the total costs on a "one-system" basis – i.e., the combined costs for EKPC and the member system – for all alternatives considered. Generally, the alternative with the lowest one-system cost is selected for implementation, unless there are overriding system benefits for a more expensive alternative.

EKPC delivery points were improved in the 2012-2014 period through the construction of new substations, as well as through upgrades of existing substations, to meet growing customer demand, enhance reliability and improve the efficiency of the system.

From 2012-2014, EKPC implemented various distribution substation projects, summarized as follows:

- Construction of one (1) new 7 MVA distribution substation
- Construction of one (1) new 14 MVA distribution substation
- Construction of three (3) new 20 MVA distribution substations
- Construction of three (3) new 25 MVA distribution substations
- Addition of two (2) new 20 MVA distribution transformers at existing stations
- Upgrades of seven (7) existing distribution substations to 20 MVA
- Upgrade of one (1) existing distribution substation to 25 MVA

New distribution delivery points enhance the utilization of the existing system by providing a new injection point into the existing distribution system. This will generally provide improved system energy losses, as well as increased voltage support.

Distribution substation transformer additions and upgrades of existing distribution substation transformers also improve system utilization by increasing capacity at an existing facility rather than building new facilities. These additions/upgrades reduce system impedance at the substation, which improves voltage drop and reduces energy losses.

In addition to the substation improvements discussed above, EKPC also worked with its member distribution cooperatives on various power factor improvement projects at the distribution level to increase available substation capacity, defer transmission construction projects, and reduce system losses. EKPC performed a power factor study to identify the substations which would provide the largest benefits to system utilization and efficiency through power factor correction. EKPC and its member systems improved the power factor at many of these substations in this period.

Further improvements are planned for EKPC's distribution substation delivery points for the 2015-2019 period. These improvements include the construction of new distribution substations, as well as upgrades of existing substations. These improvements will meet growing customer demand, enhance system reliability, and improve the efficiency of the system.

The planned improvements to EKPC distribution substations for the 2015-2019 period are summarized as follows:

- Construction of six (6) new 20 MVA distribution substations
- Addition of three (3) new 20 MVA distribution transformers at existing substations
- Upgrades of one (1) existing distribution substation to 14 MVA
- Upgrades of seven (7) existing distribution substations to 20 MVA
- Upgrades of three (3) existing distribution substations to 25 MVA

These distribution substation enhancements will improve system efficiency and utilization as described above.

In addition to these substation improvements, EKPC and its member distribution cooperatives will continue to coordinate power factor improvement projects at the distribution level to increase available substation capacity, defer transmission construction projects, and reduce system losses. EKPC annually updates its power factor correction study to identify the substations which will provide the largest benefits for system utilization and efficiency through power factor correction. EKPC and its members plan to continue to improve power factor at these locations to realize these benefits whenever feasible.

Table 8.(2)(a)-1
EKPC Free-Flowing Interconnection Capability

No.	From (EKPC)	To	Voltage kV	Ratings in MVA			
				Summer		Winter	
				Normal	Emergency	Normal	Emergency
			AEP				
1	Argentum	Millbrook Park	138	176	176	176	176
2	Argentum	Grays Branch	69	42	44	53	54
3	Falcon	Falcon	69	36	36	36	36
4	Helechawa	Lee City	69	54	54	54	54
5	Leon	Leon	69	55	71	73	85
6	Morgan County	Morgan County	69	72	72	72	72
7	Thelma	Thelma	69	69	74	83	83
	AEP Total:			504	527	547	560
			DP&L				
8	Spurlock	Stuart	345	1255	1374	1255	1374
	DP&L Total:			1255	1374	1255	1374
			Duke Energy-OHIO/KENTUCKY (DEOK)				
9	Boone	Buffington	138	247	274	296	328
10	Hebron	Hebron	138	96	117	121	139
11	Spurlock	Meldahl Dam	345	1274	1421	1648	1894
12	Webster Road	Webster Road	138	96	117	121	139
	DEOK Total:			1713	1929	2186	2500
			LG&E/KU				
13	Avon	Loudon Avenue	138	224	277	286	287
14	Baker Lane	Baker Lane Tap	138	96	117	121	139
15	Beattyville	Beattyville	69	101	124	149	163
16	Beattyville	Beattyville Tap	161-69	58	66	72	72
17	Beattyville-Powell Co.	Delvinta	161	167	204	167	227
18	Bonnieville	Bonnieville	69-138	89	109	112	129
19	Boonesboro North Tap	Boonesboro North	69-138	129	160	192	195
20	Bracken Co.	Carntown	69	41	41	72	72
21	Bracken Co.	Sharon	69	35	35	65	65
22	Cedar Grove Ind. Park	Blue Lick	161	289	289	380	380
23	Central Hardin	Hardin County	138	224	277	287	287
24	Central Hardin	Blackbranch	138	245	303	364	400
25	Clay Village	Clay Village Tap	69	35	39	47	47
26	Cooper	Elihu	161	235	289	279	305
27	Crooksville Jct.	Fawkes	69	89	98	128	134
28	East Bardstown	Bardstown Ind.	69	53	66	81	89
29	Fawkes	Fawkes	138	229	296	287	370
30	Fawkes	Fawkes Tap	138	229	284	355	387
31	Gallatin Co.	Ghent	138	229	255	287	287
32	Garrard Co.	Lancaster	69	72	101	72	101
33	Goldbug	Wofford	69	42	46	60	63
34	Green Co.	Greensburg	69	53	66	81	87
35	Green Hall Jct.	Delvinta	161	178	204	223	227

Table 8.(2)(a)-2
EKPC Free-Flowing Interconnection Capability (cont.)

No.	From (EKPC)	To	Voltage kV	Ratings in MVA Summer Normal	Summer Emergency	Winter Normal	Winter Emergency
LG&E/KU (cont.)							
36	Hodgenville	Hodgenville	69	53	60	81	89
37	Hodgenville	New Haven	69	49	49	81	89
38	Kargle	Elizabethtown	69	57	63	82	86
39	Laurel Co.	Hopewell	69	72	76	86	89
40	Liberty Church Tap	Farley	69	57	63	72	72
41	Marion Co.	Lebanon	161-138	192	220	234	250
42	Murphysville	Kenton	69	53	66	66	68
43	Murphysville	Sardis	69	41	50	60	66
44	Nelson Co.	Nelson Co Tap	69-138	144	152	172	178
45	North London	North London	69	73	76	86	89
46	North Springfield	Springfield	69	49	54	59	61
47	Owen Co.	Bromley	69	57	57	97	97
48	Owen Co.	Owen Co. Tap	69-138	139	152	172	178
49	Paris	Paris Tap	138-69	129	160	191	195
50	Penn	Scott Co.	69	56	56	82	82
51	Pittsburg Tap	Pittsburg	161-69	116	120	120	120
52	Renaker	Cynthiana Sw.	69	53	66	81	89
53	Rogersville Jct.	Rogersville	69	114	127	143	143
54	Rowan Co.	Rodburn	138	143	194	143	203
55	Sewellton	Union Underwear	69	41	41	75	75
56	Shelby Co.	Shelby Co. Tap	69	89	98	122	126
57	Somerset	Ferguson South	69	89	89	132	132
58	Somerset	Somerset South	69	56	56	78	82
59	South Anderson (624)	Bonds Mill (644)	69	89	98	128	134
60	South Anderson (634)	Bonds Mill (634)	69	89	98	128	134
61	Spurlock	Kenton	138	259	281	286	337
62	Stephensburg	Eastview	69	49	49	64	66
63	Taylor Co.	Taylor Co.	161-69	93	105	120	124
64	Tharp Jct.	Elizabethtown	69	89	98	128	134
65	Union City	Lake Reba Tap	138	245	284	364	387
66	West Garrard	West Garrard	345	1260	1403	1589	1624
	LG&E/KU Total:			7237	8307	9489	10112
TVA							
67	McCreary Co.	Jellico	161	197	197	281	281
68	McCreary Co.	Wayne Co.	161	197	197	281	281
69	McCreary Co.	Winfield	69	313	313	399	399
70	Russell Co. Tap	Wolf Creek	161	267	298	335	335
71	Summershade	Summershade	161	267	298	387	406
72	Summershade Tap	Summershade	161	207	247	259	279
73	Wayne Co.	Wayne Co.	161	118	122	118	122
	TVA Total:			1566	1672	2060	2103
			Grand Total:	12275	13809	15537	16649

Table 8.(2)(a)-3

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2015 – 2030)	
A. New Transmission Lines and Status Changes Project Description	**Needed In-Service Date**
Operate the Cynthiana-Headquarters and Sideview-Cane Ridge 69 kV lines normally-closed.	12/2015
Establish a 69 kV interconnection with Duke Energy at Hebron by installing two 69 kV circuit breakers at EKPC's Hebron.	6/2015
Construct a new 69 KV line between KU's West Frankfort substation and the Bridgeport substation (1.2 miles). Install a 69 KV switch between the Bridgeport #1 and Bridgeport #2 substations and operate this switch normally-open, with Bridgeport #1 served from the new line and Bridgeport #2 served from the existing tap line.	6/2016
Construct a new 69 KV line from Beattyville Distribution-Oakdale using 556 ACSR (11.66 miles). Operate this new line normally closed and operate the existing Oakdale Jct.-Oakdale line normally open.	12/2017
Construct a 2nd 69 KV line, using 556.5 MCM ACSR conductor between the Russell County and Sewellton substations (0.88 miles). Install terminal equipment at the Russell County substation. Serve the Sewellton distribution station radially from the Russell County substation.	12/2021
Construct a 2nd 69 KV line, using 266.8 MCM ACSR conductor between the Powell County and Stanton substations (0.10 miles). Install terminal equipment at the Powell County substation. Serve the Stanton distribution station radially from the Powell County substation.	12/2022
Construct a new 69 KV line using 556.5 MCM ACSR conductor between the Tommy Gooch and KU Standford substations (3.9 miles). Operate this line normally-open.	12/2023
Construct a new 69 KV line using 556.5 MCM ACSR conductor between the Floyd and Woodstock substations (7.2 miles). Install two 69 KV breakers at Walnut Grove.	12/2029

Table 8.(2)(a)-4

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2015 – 2030)	
B. New Transmission Substations Project Description	**Needed In-Service Date**
NONE	

Table 8.(2)(a)-5

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2015 – 2030)	
C. New Transmission Switching Stations Project Description	**Needed In-Service Date**
NONE	

Table 8.(2)(a)-6

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2015 – 2030)	
D. Transmission Transformer Upgrades Project Description	**Needed In-Service Date**
Bullitt County 161-69 kV Transformer Replacement – Upgrade to 150 MVA	6/2019

Table 8.(2)(a)-7

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2015 – 2030)	
E. Terminal Facility Upgrades Project Description	**Needed In-Service Date**
Increase the Zone 3 distance relay setting at Barren County associated with the Barren County-Bonnieville 69 kV line to at least 85 MVA.	6/2019
Upgrade the 4/0 bus and jumpers at Nelson County substation associated with the Nelson County-West Bardstown Jct. 69 kV line using 500 MCM copper or equivalent equipment.	6/2020
Upgrade the 4/0 bus and jumpers at Denny substation associated with the Denny-Wayne County 69 kV line using 500 MCM copper or equivalent equipment.	6/2020
Upgrade the 600A CT at Denny associated with the Denny-Wayne County 69 kV line with a 1200A CT.	6/2020
Upgrade the 4/0 bus and jumpers at Green County substation associated with the Green County-KU Taylor County 69 kV line using 500 MCM copper or equivalent equipment.	6/2023
Upgrade the 400 A metering CT at Laurel County associated with the Laurel County-KU Hopewell 69 KV line section with an 800 A CT.	6/2024
Upgrade the 600 A disconnect switch switches W59-613 and W59-615 at the Barren County substation associated with the Barren County-Bonnieville 69 KV line using 1200 A switches.	6/2024
Upgrade the 600 A disconnect switches W59-633 and W59-635 at the Barren County substation associated with the Barren County-Cave City Jct. 69 KV line using 1200 A switches. Upgrade the 600 A switch W49-615 at Cave City Jct. with a 1200 A switch.	6/2024
Upgrade the 750 MCM copper bus at Dale Station associated with the JK Smith-Dale 138 kV line using 1-inch IPS or equivalent equipment.	6/2026
Upgrade the 750 MCM jumper associated with the Summer Shade 161-68 kV transformer using 95 W MCM ACSR or larger conductor.	6/2029
Upgrade the 4/0 jumpers at Boone County substation associated with the Boone County-Hebron 69 kV line using 500 MCM copper or equivalent equipment.	6/2030
Upgrade the 4/0 bus and jumpers at Three Links Jct. substation associated with the West Berea Jct.-Three Links Jct. 69 kV line using 500 MCM Copper or equivalent equipment.	12/2030

Table 8.(2)(a)-8

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2015 – 2030)	
F. Transmission Line Re-conductor/Rebuilds Project Description	**Needed In-Service Date**
Re-conductor the Cynthiana Jct-Headquarters 69 kV line section (10.23 miles) using 556.5 MCM ACTW wire.	12/2015
Re-conductor the Owen County-New Castle 69 KV line section (19.9 miles) using 556.5 MCM ACTW conductor	6/2016
Re-conductor the Brodhead-Three Links Jct 69 kV line section (8.2 miles) using 556.5 MCM ACTW wire.	12/2017
Re-conductor the Cave City Jct.-Seymour Tap 69 KV line section (0.51 miles) using 556.5 MCM ACTW conductor.	6/2019
Re-conductor the Leon-Airport Road 69 kV line section (5.72 miles) using 556.5 MCM ACTW conductor.	12/2019
Re-conductor the Seymour Tap-KU Horse Cave Tap 69 KV line section (1.98 miles) using 556.5 MCM ACTW conductor.	6/2021
Re-conductor the Albany-Snow Jct 69 kV line section (4.40 miles) using 556.5 MCM ACTW wire.	12/2021
Re-conductor the South Bardstown-W. Bardstown Jct 69 kV line section (2.5 miles) using 556.5 MCM ACTW wire.	12/2022
Re-conductor the Fort Knox Tap-Rineyville Tap 69 KV line section (0.40 miles) using 556.5 MCM ACTW conductor.	6/2024
Re-conductor the South Bardstown-West Bardstown 69 KV line section (2.0 miles) using 556.5 MCM ACTW conductor.	12/2027
Re-conductor the Renaker-Williamstown 69 kV line section (18.45 miles) using 556.5 MCM ACTW conductor.	6/2030
Re-conductor the Headquarters Millersburg Jct. 69 kV line section (5.12 miles) using 556.5 MCM ACTW conductor.	12/2030

Table 8.(2)(a)-9(a)

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2015 – 2030)	
G. Transmission Line High Temperature Upgrades Project Description	**Needed In-Service Date**
Increase the MOT of the Helechawa-Sublett Junction 69 kV line section to 167°F.	6/2015
Increase the MOT of the Glendale-Hodgenville 69 kV line section to 212°F.	6/2015
Increase the MOT of the J.K. Smith-Union City 138 kV line section to 330°F (LTE at 312°F).	6/2015
Increase the MOT of the Headquarters-Millersburg Jct. 69 kV line section to 167°F.	6/2015
Increase the MOT of the Colesburg Jct.-Colesburg 69 kV line section to 167°F.	6/2015
Increase the MOT of the Etown EK #1-Tunnel Hill Junction 69 kV line section to 284°F. (LTE at 266°F)	6/2015
Increase the MOT of the Union City-Lake Reba Tap 138 kV line section to 330°F. (LTE at 312°F)	6/2015
Increase the MOT of the Kargle-KU Elizabethtown 69 KV line section to 266°F. (LTE at 248°F)	6/2015
Increase the MOT of the Cave City-Seymour Tap 69 KV line section to 302°F. (LTE at 284°F)	6/2015
Increase the MOT of the Seymour Tap-KU Horse Cave Tap 69 KV line section to 302°F. (LTE at 284°F)	6/2015
Increase the MOT of the Owens Illinios_Bluegrass Parkway Tap 69 KV line section to 212°F.	6/2015
Increase the MOT of the North Springfield-South Springfield Jct. 69 kV line section to 167°F.	6/2015
Increase the MOT of the Loretto-Sulphur Creek 69 kV line section to 167°F.	6/2015
Increase the MOT of the Loretto-South Springfield Junction 69 kV line section to 212°F.	6/2015
Increase the MOT of the West Bardstown Jct.- South Bardstown 69 kV line section to 284°F. (LTE at 266°F)	6/2016
Increase the MOT of the Oakdale Jct.-Oakdale 69 kV line section to 167°F.	6/2016

Table 8.(2)(a)-9(b)

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2015 – 2030)	
G. Transmission Line High Temperature Upgrades (continued) Project Description	**Needed In-Service Date**
Increase the MOT of the Pelfrey Jct.-Pelfrey 69 kV line section to 167°F.	6/2016
Increase the MOT of the Zula Tap-Zula 69 kV line section to 167°F.	6/2016
Increase the MOT of the Ninevah-Ninevah KU Junction 69 kV line section to 167°F.	6/2016
Increase the MOT of the Arkland Tap-Oven Fork 69 kV line section to 167°F.	6/2016
Increase the MOT of the Mount Olive Jct.-Mount Olive 69 kV line section to 167°F.	6/2016
Increase the MOT of the Davis Junction-Fayette 69 kV line section to 266°F. (LTE at 248°F)	6/2017
Increase the MOT of the Booneville Tap-Booneville 69 kV line section to 167°F. COMPLETE	6/2017
Increase the MOT of the South Bardstown-West Bardstown 69 KV lin section to 284°F. (LTE at 266°F)	6/2017
Increase the MOT of the Eberle Tap-Eberle 69 kV line section to 167°F.	6/2017
Increase the MOT of the Rowan County-Elliottville 69 kV line section to 167°F.	6/2017
Increase the MOT of the Mount Sterling-Fogg Pike-Reid Village 69 kV line section to 167°F.	6/2017
Increase the MOT of the Jellico Creek Tap-Jellico Creek 69 kV line section to 167°F.	6/2017
Increase the MOT of the Penn-Keith 69 kV line section to 167°F.	6/2017
Increase the MOT of the Tharp Tap-Tharp 69 kV line section to 167°F.	6/2017
Increase the MOT of the Big Bone Tap-Big Bone 69 kV line section to 167°F.	6/2017
Increase the MOT of the Cave Run Tap-Cave Run 69 kV line section to 167°F.	6/2017
Increase the MOT of the Carson-New Liberty 69 kV line section to 167°F.	6/2017
Increase the MOT of the Griffin-Griffin Junction 69 kV line section to 167°F.	6/2017
Increase the MOT of the Bacon Creek Tap-South Corbin 69 kV line section to 212°F.	6/2018
Increase the MOT of the J.K. Smith-Dale 138 kV line section to 275°F. (LTE at 257°F)	6/2018
Increase the MOT of the Baker Lane-Holloway Jct. 69 KV line section to 266°F. (LTE at 248°F)	12/2023
Increase the MOT of the Rineyville-Smithersville Tap 69 KV line section to 302°F. (LTE at 284°F)	6/2024
Increase the MOT of the Stephensburg_Upton Tap 69 KV line section to 302°F. (LTE at 284°F)	6/2024
Increase the MOT of the Plumville-Rectorville 69 kV line section to 212°F.	6/2030

Table 8.(2)(a)-10

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2015 – 2030)	
H. Capacitor Bank Additions Project Description	**Needed In-Service Date**
Retire the Mckee 10.7 MVAR capacitor bank.	12/2015
Install a 14.286 MVAR, 69 kV capacitor bank at Magoffin County Substation.	12/2015
Retire the Hilda 18.37 MVAR capacitor bank and move to Big Woods.	12/2016
Install a 22.96 MVAR, 69 kV capacitor bank at Owen County Substation.	6/2017
Install a 161 kV, 81.636 MVAR capacitor bank (2 stages of 40.818 MVARs each) at Cooper Station	12/2017
Resize the Cedar Grove 69 kV capacitor bank from 10.8 to 20.409 MVAR.	6/2018
Install a 18.368 MVAR, 69 KV capacitor bank at Maggard substation	12/2019
Install a 12.245 MVAR, 69 kV capacitor bank at the East Campbellsville Substation	6/2020
Install a 17.858 MVAR, 69 kV capacitor bank at Fox Hollow Substation.	12/2020
Resize the Williamstown 69 KV capacitor bank from 8.4 MVAR to 11.225 MVAR.	12/2021
Install a 33.165 MVAR, 69 KV capacitor bank at Elizabethtown substation.	12/2021
Install a 16.837 MVAR, 69 KV capacitor bank at Wayne County substation.	12/2021
Install a 25.511 MVAR, 69 KV capacitor bank at Sewellton Junction substation.	12/2021
Install a 69 kV, 51.022 MVAR capacitor bank at Somerset Substation.	12/2024
Install a 69 kV, 10.715 MVAR capacitor bank at Rowan County Substation.	12/2030
Increase the size of the 3M 69 kV capacitor bank from 12.24 MVAR to 16.84 MVAR.	12/2030

Table 8.(2)(a)-11

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2015 – 2030)	
I. New Distribution Substations and associated Tap Lines Project Description	**Needed In-Service Date**
Construct a new Pleasant Grove #2 69-12.5 kV, 12/16/20 MVA Substation and associated 69 kV tap line (0.1 mile)	6/2015
Construct a new Bridgeport #2 69-25 kV, 12/16/20 MVA substation and associated 69 kV tap line (0.1 miles). Replace the existing Bridgeport #1 15/20/25 MVA transformer with a 12/16/20 MVA transformer.	6/2015
Construct a new South Bardstown 69-12.5 KV, 12/16/20 MVA substation and associated 69 KV tap line (0.2 mile) to the West Bardstown Jct.- West Bardstown 69 KV line section.	6/2016
Construct a new Long Lick 69-25 kV, 12/16/20 MVA Substation and associated 69 kV tap line (0.7 miles)	6/2016
Construct a new Defoe 69-12.5 KV, 12/16/20 MVA substation and associated 69 KV tap line (5.0 mile) to the Clay Village-New Castle 69 KV line section.	12/2016
Construct a new Roanoke 69-12.5 kV, 12/16/20 MVA Substation and associated 69 kV tap line (5.0 miles)	12/2016
Construct a new Big Woods 69-12.5 kV, 12/16/20 MVA Substation and associated 69 kV tap line (0.2 mile)	12/2016
Construct a new Roseville 69-25 kV, 12/16/20 MVA Substation and associated 69 kV tap line (3.5 miles)	12/2016
Construct a new Tommy Gooch #2 69-25 kV, 12/16/20 MVA Substation and associated 69 kV tap line (0.1 mile)	12/2017

Table 8.(2)(a)-12

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2015 – 2030)	
J. Distribution Substation Additions and Upgrades Project Description	**Needed In-Service Date**
Upgrade the existing Bank Lick 69-12.5 kV, 11.2/14 MVA Substation to 12/16/20 MVA.	6/2015
Upgrade the existing Peytons Store 69-25 kV, 11.2/14 MVA Substation to 12/16/20 MVA.	12/2015
Upgrade the existing Jellico Creek 69-13.2 kV, 5.6/7 MVA Substation to 11.2/14 MVA, and convert to 25 kV low-side.	12/2015
Upgrade the existing Williamstown 69-12.5 kV, 11.2/14 MVA Substation to 15/20/25 MVA.	3/2016
Upgrade the existing Holloway 69-12.5 kV, 11.2/14 MVA Substation to 15/20/25 MVA.	6/2016
Upgrade the existing Rectorville 69-12.5 kV, 11.2/14 MVA Substation to 12/16/20 MVA, and convert to 25 kV low-side.	6/2017
Upgrade the McKinney's Corner 69-12.5 kV, 6 MVA substation to 12/16/20 MVA.	12/2017
Upgrade the existing W.M. Smith #2 69-12.5 kV, 11.2/14 MVA Substation to 15/20/25 MVA.	6/2019
Upgrade the existing Shepherdsville #2 69-12.5 kV, 11.2/14 MVA substation to 12/16/20 MVA.	6/2019
Upgrade the existing Mt. Washington #1 69-12.5 kV, 11.2/14 MVA substation to 12/16/20 MVA.	6/2019
Upgrade the existing Phil 69-12.5 kV, 11.2/14 MVA substation to 12/16/20 MVA	12/2019

SECTION 7.0

PLANS FOR EXISTING GENERATING UNITS

SECTION 7.0

PLANS FOR EXISTING GENERATING UNITS

7.1

Existing Generation

Maintenance management for existing generation is vital to keeping the generating facilities reliable, productive, efficient, and cost effective. EKPC has developed a long-range plan of maintenance needs for each of the existing generating units, which is discussed in the following subsection. EKPC will be shuttering Dale Power Station on April 15, 2016. Please also see the discussion in Section 1.4, Power Supply Actions, in the Executive Summary of this IRP. EKPC will work with Federal and State stakeholders to ensure the economic viability of its existing resources to meet the challenges and opportunities surrounding climate change.

7.2

Maintenance of Existing EKPC Generating Units

Current facilities at Dale Power Station were placed in operation in 1954-60, Cooper Power Station in 1965-69, and Spurlock Power Station in 1977-81, with the Gilbert Unit in 2005, and Spurlock Power Station Unit No. 4 in 2009. J.K. Smith Station combustion turbines were placed in operation in 1999, 2001, and 2005, with two new units placed into operation in 2010. Each of EKPC's generating plants was state-of-the-art at the time of their construction and was designed to operate under conditions existing at that time. The continued operation of these plants requires both normal maintenance and a systematic review of current conditions needed for continued operation.

In 1987, EKPC began work on a formal maintenance program called MEAGER (Maintaining Electrical and Generating Equipment Reliability). Through proper planning and implementation, EKPC effectively manages operations, while meeting environmental compliance regulations, to provide reliable, economical electric service to its member systems and their retail consumers. This plan for maintenance is developed following the review of various plant subsystems, assimilation of operational data, and review of past operating history.

Methodology for MEAGER Program

The areas addressed in the development of the current plan include safety, generating plant performance, operation, maintenance, and regulatory compliance.

The MEAGER plan covers a five-year look ahead at major projects necessary to ensure safe, reliable, and affordable power production. The existing MEAGER plan is reviewed along with meetings with plant, engineering, and environmental individuals, to develop the latest plan.

Each specific major project scheduled in the MEAGER plan is again reviewed and justified prior to requesting approval from the EKPC Board of Directors for implementation of the project. Prior to requesting this approval, an analysis is conducted taking into account costs and timing of the project, to ensure that completion of the proposed project is the most economical decision for EKPC. Justifications are developed based on the economic analysis and any other benefits such as safety or regulatory requirements. Depending on the cost of the project, the economic analysis results and justification are then presented to the Board along with a request to approve the project. Smaller projects go through EKPC's normal approval process.

2015 MEAGER Study

The MEAGER Program covers the time frame of 2015 through 2019. Table 8.(2)(a)-1 through Table 8.(2)(a)-19 on pages 143-159 lists the major projects planned for each plant during the five-year period.

Table 8.(2)(a)-1
($100,000 and Above)

Cooper Power Station

Description	Operating Unit	Date
Structural Steel Painting	CP00	2015
Boiler Condition Assessment - Unit No. 1	CP01	2015
High Energy Piping Assessment	CP01	2015
Install New Emergency Drain Valves System for HP FWH	CP02	2015
No. 7 Feedwater Heater - Retube - Unit No. 2	CP02	2015
Refurbish 3A Belt	CP00	2015
Capital:		
Transport Line Isolation Valves - Unit No. 1 and No. 2	CP01 and CP02	2015
Distilled Water Tank - Additional Tank	CP00	2015
Four Joy Sootblower Compressors	CP00	2015
DSC Control - Unit No. 1 and No. 2	CP01 and CP02	2015
Air Heater Rebuild - Unit No. 1	CP01	2015
Structural Steel Painting	CP00	2016
Fire Sprinklers on 1A and 2A Coal Conveyors	CP00	2016
Repair Unit No. 2 Intake Elevator	CP02	2016
No. 1 Intake Elevator Controls Upgrade	CP01	2016
Wind Box Divider Floor Dutchmans - Unit No. 1	CP01	2016
Primary Superheater Dutchman - Unit No. 2	CP02	2016
Overhaul 1A Circulating Water Pump - Unit No. 1	CP01	2016
Replace 9 IK Sootblowers - Unit No. 1	CP01	2016
Capital:		
Turbine and Generator Controls - Unit No. 1	CP01	2016

Table 8.(2)(a)-2

Cooper Power Station

Description	Operating Unit	Date
High Energy Piping and Testing	CP02	2017
Turbine Valve Outage	CP02	2017
Rebag 1/4 of Baghouse	CP02	2017
Wedge Check - Generator	CP02	2017
Boiler Condition Assessment	CP02	2017
Boiler Condition Assessment	CP01	2017
Replace Submerged Drag Chain	CP01	2017
Boiler Assessment/Scaffold	CP01	2017
Capital:		
Replace Unit 1 Mechanical Dust Collectors	CP01	2017
Furnish and Install SCR Catalyst	CP02	2017
Capital:		
Replace unit 2 #7 F.W.Heater	CP02	2018
Rebuild Circulating Water Pump	CP02	2019
Rebag 1/4 of Baghouse	CP02	2019
Major Turbine Overhaul/Valve Outage	CP01	2019
High Energy Piping Assessment	CP01	2019
Capital:		
Replace Secondary Superheater	CP01	2019
Furnish and Install SCR Catalyst	CP02	2019
Replace Primary Superheat Panels	CP02	2019
Replace Reheat Superheater Panels	CP02	2019
Replace Economizer	CP02	2019
Replace Primary Superheater	CP01	2019

CP00 - Common

CP01 - Cooper 1

CP02 - Cooper 2

Table 8.(2)(a)-3

Dale Power Station

Description	Operating Unit	Date
NOTE: No maintenance projects are scheduled. Any capital projects related to Dale Power Station are shown in other department budgets. See Construction		

Table 8.(2)(a)-4

Spurlock Power Station

Description	Operating Unit	Date
Misc. Structure Maintenance - Day/Night Lighting Control	SP00	2015
Misc. Structure Maintenance - Steel Structural Repairs and Painting	SP00	2015
Plant Water Supply & Drain System- Intake Screen Replacement	SP00	2015
Plant Water Supply & Drain System - No. 1 Solid Contact Unit Shaft Replacement	SP00	2015
Misc. Boiler Plant Maint - Outage Boiler Inspection/Discovery Repair	SP01	2015
Misc. Boiler Plant Maint - 1A BFP Overhaul	SP01	2015
Misc. Boiler Plant Maint. - Expansion Joint Repairs	SP01	2015
Boiler Plant Maint. - Outage Boiler Inspection/Discovery Repair	SP02	2015
Boiler Plant Maint. - Rebuild Pulverizers B and C	SP02	2015
Boiler Plant Maint. - Overhaul Boiler Water Circulating Pump 2D	SP02	2015
Boiler Plant Maint. - Expansion Joint Repairs	SP02	2015
Boiler Maint. - Amstar Flame Spray Corner Maintenance	SP03	2015
Boiler Maint. - Outage Boiler Inspection/Discovery Repair	SP03	2015
Boiler Maint. - Feed pump Overhaul "B" - 3B Feed Pump Volute Replacement	SP03	2015
Boiler Maint. - High Energy Piping Assessment	SP03	2015
Boiler Maint. - Amstar Flame Spray Corner Maintenance	SP04	2015
Boiler Maint. - Feed Pump Voith Drive Replacement A	SP04	2015
Boiler Maint. - Outage Boiler Inspection/Discovery Repair	SP04	2015
Boiler Maint. - Outage Boiler and Airheater Inspection and Repair	SP04	2015
Boiler Pollution Control Equipment - Refractory	SP03	2015
Boiler Pollution Control Equipment - Replace Furnace Nozzles	SP03	2015
Boiler Pollution Control Equipment - Replace Cyclone C Target Wall	SP03	2015
Boiler Pollution Control Equipment - Replace Cyclone Special Shape Brick Near Support of all Three Cyclones	SP03	2015
Boiler Pollution Control Equipment - Replace Furnace to Fludized Bed Ash Coolers Box Solid Return Duct Metal Joint	SP03	2015

Table 8.(2)(a)-5

Spurlock Power Station

Description	Operating Unit	Date
Boiler Pollution Control Equipment - Refractory	SP04	2015
Boiler Pollution Control Equipment - 25% of Furnace Nozzles	SP04	2015
Electrostatic Precipitator - Outage Precipitator Inspection & Repairs	SP01	2015
Electrostatic Precipitator - Outage Precipitator Inspection & Repairs	SP02	2015
Baghouse, SNCR & FDA - Inspect and Repair - Unit 3 Baghouse	SP03	2015
Baghouse, SNCR, & FDA - Baghouse Turning Vanes	SP03	2015
Baghouse, SNCR, & FDA - Inspect and Repair - Unit 4 Baghouse	SP04	2015
Baghouse, SNCR, & FDA - Replace Pulse Tube Elbows with SS Ones	SP03	2015
Baghouse, SNCR, & FDA - Baghouse Bag Replacements	SP04	2015
Upgrade to Anyhdrous Ammonia (NH3 System)	SP00	2015
Common NH3 Farm Maint. - Ammonia Tank Farm Inspection	SP00	2015
Material Handling System -Replace Flights on SR1	SP02	2015
Scrubber Maint. - WESP SIRS Clean/Inspect/Repair	SP21	2015
Scrubber Maint. - (2) Recycle Pump Impellers	SP21	2015
Turbine Maint. - Cleaning Cooling Water Heat Exchangers	SP04	2015
Turbine/Generator - Major Turbine Overhaul - Unit 3	SP03	2015
Capital:		
Unit 4 Fluidized Bed Ash Cooler Circuits - Install New Design	SP04	2015
Replace Unit 4 J-Duct & Settling Chamber (Lined with HexMesh & Refractory)	SP04	2015
Units 3 & 4 Electric Driven Feed Pump	SP03 & SP04	2015
Water Service Program Logic Controler Conversion to DCS, Valves Control Wiring	SP00	2015
Unit 4 Cooling Tower Fill	SP04	2015
Install Bypass Chutes in Transfer Towers 2 & 3	SP00	2015
Flue-Gas Desulphurization Service Water Line	SP21 & SP22	
Units 1 and 2 Dry Sorbent Injection System	SP01 & SP02	2015
Units 1 & 2 Instrument Air Dryers	SP01 & SP02	2015
U1,U2 Crane in Bays	SP01 & SP02	2015
Emergency Gen Sync	SP00	2015
Replace Pulverizer Classifiers	SP02	2015
Unit No. 3 Efficiency Upgrade	SP03	2015

Table 8.(2)(a)-6

Spurlock Power Station

Description	Operating Unit	Date
Misc. Structure Maintenance - Day/Night Lighting Control	SP00	2016
Misc. Structure Maintenance - Ash Haul Bridge Maintenance	SP00	2016
Misc. Structure Maintenance - Turbine Room Lighting Unit 1 & 2	SP00	2016
Misc. Structure Maintenance - Unit 1 & 2 Lighting Coal Handling	SP00	2016
Misc. Structural Maintenance - Steel Structural Repairs & Painting	SP00	2016
Plant Support Systems - Old Crusher Building Elevator	SP00	2016
Plant Support Systems - Unit No. 1 Elevator Complete Overhaul	SP00	2016
Plant Support Systems - Unit No. 2 Elevator Complete Overhaul	SP00	2016
Plant Support Systems - Remaining Traction Elevators (Rope Grabbers)	SP00	2016
Boiler Plant Maint. - Outage Boiler Inspection/Discover Repair	SP01	2016
Boiler Plant Maint. - 2B Boiler Feed Pump Overhaul	SP01	2016
Boiler Plant Maint. - Repair Penthouse Casing Leak	SP01	2016
Boiler Plant Maint. - Expansion Joint Repairs	SP01	2016
Boiler Plant Maint. - Boiler Seal Trough & Skirt Replacements	SP01	2016
Boiler Plant Maint. - 2A Boiler Feed Pump Overhaul	SP02	2016
Boiler Plant Maint. - Chimney Painting	SP02	2016
Boiler Plant Maint. - Outage Boiler Inspection/Discovery Repair	SP02	2016
Boiler Plant Maint. - Pulverizer Overhaul A, D, & E	SP02	2016
Boiler Plant Maint. - FD Fan Rotor Rebuild	SP02	2016
Boiler Plant Maint. - Replace five Metal Expansion Joints hot PA to Pul.	SP02	2016
Boiler Plant Maint. - Expansion Joint Repairs	SP02	2016
Boiler Plant Maint. - Abandoned Chimney Maintenance	SP02	2016
Boiler Maintenance - Amstar Flame Spray Corner Maintenance	SP03	2016
Boiler Maintenance - Outage Boiler and Airheater Inspection and Repairs	SP03	2016
Boiler Maintenance - Chemical Clean of Boiler	SP03	2016
Boiler Maintenance - Primary Air/Secondary Air/ID Fan Motor Overhaul	SP03	2016
Boiler Maintenance - Amstar Flame Spray Corner Maintenance	SP04	2016
Boiler Maintenance - High Energy Piping Assessment	SP04	2016
Boiler Maintenance - Feed Pump Voith Drive Replacement 4B	SP04	2016
Boiler Maintenance - Outage Boiler & Airheater Inspection & Repairs	SP04	2016
Boiler Pollution Control. Equipment - Refractory	SP03	2016
Boiler Pollution Control Equipment-Replace Cyclone Target Wall "A"	SP03	2016

Table 8.(2)(a)-7

Spurlock Power Station

Description	Operating Unit	Date
Boiler Pollution Control Equip. 3A & 3B Limestone Mills Bull Rings	SP03	2016
Boiler Pollution Control Equipment - Repairs to Superheat Box	SP03	2016
Boiler Pollution Control Equipment - Refractory	SP04	2016
Cooler Box SRD Metal Joint	SP04	2016
Boiler Pollution Control Equipment - 4A and 4B Limestone Mills - Bull Rings	SP04	2016
Electrostatic Precipitator - Outage Precipitator Inspection and Repairs	SP01	2016
Electrostatic Precipitator - Precipitator Hoppers	SP02	2016
Electrostatic Precipitator -Outage Precipitator Inspection and Repairs	SP02	2016
Baghouse Clean Side Floor Erosion	SP03	2016
Baghouse, SNCR, & FDA - Inspect and Repair Baghouse	SP03	2016
Baghouse, SNCR, & FDA - Baghouse Clean Side Floor Erosion	SP04	2016
Baghouse, SNCR, and FDA - Inspect and Repair Baghouse	SP04	2016
Common NH3 Farm Maint. - Upgrade to Anhydrous Ammonia (NH3 System)	SP00	2016
Coal Handling System - Replace UC-5 Conveyor Belt	SP00	2016
Coal Handling System - Replace Upper Half of UC4 Conveyor Hoods	SP00	2016
Coal Handling System - Dredge River Around Unloading Cells	SP00	2016
Coal Handling System - Barge Mooring Cells	SP00	2016
Coal Handling System - Replace Barge Unloader Buckets	SP00	2016
Material Handling System - Hood Covers	SP01	2016
Material Handling System - Replace CAT Chain and Sprockets on SR2	SP01	2016
Material Handling System - Replace Flights on SR2	SP01	2016
Material Handling System - Hood Covers	SP02	2016
Material Handling System - Replace BC2A and BC2B Discharge Chutes Including Flopgates	SP02	2016
Material Handling System - Replace PC2A & PC2B Discharge Chutes	SP02	2016
Material Handling System - Replace Lower Slew Bearing	SP02	2016
Mobile Equipment - 988H Loader Powertrain Rebuild	SP00	2016
Mobile Equipment - No. 3 Bulldozer Powertrain Rebuild	SP00\	2016
Ash System Maintenance - Transfer Building (2) Outages	SP00	2016
Scrubber Maintenance - WESP SIRS Clean/Inspect/Repair	SP21	2016
Scrubber Maintenance - WESP SIRS Clean/Inspect/Repair	SP22	2016
Turbine Maintenance - Cooling Tower Controls	SP01	2016
Turbine Maintenance - Cooling Tower Structural Repairs	SP01	2016
Turbine Maintenance - Cooling Towel Controls	SP02	2016
Turbine Maintenance - Cooling Tower Shroud Replacements	SP02	2016
Turbine Maintenance - Turbine Valves	SP03	2016
Turbine Maintenance - CCW Heat Exchange Cleaning	SP04	2016

Table 8.(2)(a)-8

Spurlock Power Station

Description	Operating Unit	Date
Capital		
Unit No. 1 Absorber System Upgrade	SP01	2016
Unit No. 3 and No. 4 Hydrated Lime System	SP03 & SP04	2016
FBHE/FBAC Air Source	SP03 & SP04	2016
Unit No. 2 Absorber System Upgrade	SP02	2016
Unit No. 1 Condenser Retrofit/Redesign	SP01	2016
Unit No. 3 and No. 4 Electric Driven Boiler Feed Pump	SP03 & SP04	2016

Table 8.(2)(a)-9

Spurlock Power Station

Description	Operating Unit	Date
Misc. Structure Maintenance - Day/Night Lighting Control	SP00	2017
Misc. Structure Maintenance - Ash Road Bridge Painting	SP00	2017
Misc. Boiler Plant Maint. - Outage Boiler Inspection/Discovery Repair	SP01	2017
Misc. Boiler Plant Maint. - Repair Penthouse Casing Leak	SP01	2017
Misc. Boiler Plant Maint. - Expansion Joint Repairs	SP01	2017
Misc. Boiler Plant Maint. - Outage Boiler Inspection/Discovery Repair	SP02	2017
Misc. Boiler Plant Maint. - 1B Boiler Feed Pump Overhaul	SP02	2017
Misc. Boiler Plant Maint. - Overhaul Boiler Water Circulating Pump 2A	SP02	2017
Misc. Boiler Plant Maint. - 2A ID Fan Rotor Swap	SP02	2017
Misc. Boiler Plant Maint. - Pulverizer (B&C) Floor Replacements	SP02	2017
Misc. Boiler Plant Maint. - Expansion Joint Repairs	SP02	2017
Boiler Maintenance - Amstar Flame Spray Corner Maintenance	SP03	2017
Boiler Maintenance - Outage Boiler & Airheater Inspection & Repairs	SP03	2017
Boiler Maintenance - Amstar Flame Spray Corner Maintenance	SP04	2017
Boiler Maintenance - Outage Boiler & Airheater Inspection & Repairs	SP04	2017
Boiler Maintenance - Outage Boiler & Airheater Inspection & Repairs	SP04	2017
Boiler Pollution Control Equipment - Refractory	SP03	2017
Boiler Pollution Control Equipment - Replace "A" Cyclone Target Wall	SP03	2017
Boiler Pollution Control Equipment - Repairs to Reheat Box Lids and Tube Penstrations	SP03	2017
Boiler Pollution Control Equipment - Install Additional Dry Ash Telescopic	SP03	2017
Electrostatic Precipitator - Outage - Precipitator Inspection & Repairs	SP01	2017
Electrostatic Precipitator - Outage - Precipitator Inspection & Repairs	SP02	2017

Table 8.(2)(a)-10

Spurlock Power Station

Description	Operating Unit	Date
Baghouse, SNCR, & DSA - Inspect and Repair	SP03	2017
Baghouse, SNCR, & DSA - Baghouse Bag Replacement	SP03	2017
Baghouse, SNCR, & DSA - Inspect and Repair	SP04	2017
Coal Handling System Maint. - Paint Barge Unloader, UC3, UC4, UC5 and Surge Bins	SP00	2017
Coal Handling System Maint. - Replace UC5 Conveyor	SP00	2017
Coal Handling System Maint - Dredge River Around Unloading Cells	SP00	2017
Material Handling System - Replace Flights on SR1	SP02	2017
Material Handling System - Replace PC1B Conveyor Belt	SP02	2017
Ash System Maintenance - Transfer Building (2) Outages	SP00	2017
Scrubber Maintenance - WESP SIRS Clean/Inspect/Repair	SP21	2017
Scrubber Maintenance - WESP SIRS Clean/Inspect/Repair	SP22	2017
Turbine Maintenance - Replace Cooling Water Pumps	SP02	2017
Turbine Maintenance - Replace Battery Banks	SP03	2017
Turbine Maintenance - Replace Battery Banks	SP04	2017
Capital:		
Unit No. 1 Absorber System Upgrade	SP01	2017
Unit No. 3 and No. 4 Hydrated Lime System	SP03 & SP04	2017
Unit No. 2 Absorber System Upgrade	SP02	2017
Unit No. 1 Condenser Retrofit/Redesign	SP01	2017
Unit No. 3 and No. 4 Electric Driven Feed Pump	SP03 & SP04	2017

Table 8.(2)(a)11

Spurlock Power Station

Description	Operating Unit	Date
Misc. Structure Maintenance - Day/Night Lighting Control	SP00	2018
Misc. Boiler Plant Maint. - Outage Boiler Inspection/Discovery Repair	SP01	2018
Misc.. Boiler Plant Maint . - Expansion Joint Repairs	SP01	2018
Misc. Boiler Plant Maint. - Outage Boiler Inspection/Discovery Repair	SP02	2018
Misc. Boiler Plant Maint. - Overhaul Boiler Water Circulating Pump 2C	SP02	2018
Misc. Boiler Plant Maint. - 2B ID & 2A FD Fan Rotor Swaps	SP02	2018
Misc. Boiler Plant Maint. - Pulverizer (A,D,&E) Floor Replacements	SP02	2018
Misc. Boiler Plant Maint. - Air Heater Sector Plates/Adjusters/Replc.	SP02	2018
Misc. Boiler Plant Maint. - Expansion Joint Repairs	SP02	2018
Misc. Boiler Plant Maint. - Amstar Flame Spray Corner Maint.	SP03	2018
Misc. Boiler Plant Maint. - Outage Boiler & Airheater Inspection & Repair	SP03	2018
Misc. Boiler Plant Maint. - 4A Feed Pump Volute Replacement	SP04	2018
Misc. Boiler Plant Maint - Chemical Clean of Boiler	SP04	2018
Misc. Boiler Plant Maint. - Amstar Flame Spray Corner Maint.	SP04	2018
Misc. Boiler Plant Maint. - Outage Boiler & Airheater Inspection & Repair	SP04	2018
Boiler Pollution Control Equipment - Refractory	SP03	2018
Boiler Pollution Control Equipment - Replace "B" Cyclone Target Wall	SP03	2018
Boiler Pollution Control Equipment - 3A and 3B Limestone Mills - Bull Rings	SP03	2018
Boiler Pollution Control Equipment - Refractory	SP04	2018
Electrostatic Precipitator - Outage - Precipitator Inspection & Repairs	SP01	2018
Electrostatic Precipitator - Outage - Precipitator Inspection & Repairs	SP02	2018
Baghouse, SNCR, & FDA - Inspect and Repair	SP03	2018
Baghouse, SNCR, & FDA - Inspect and Repair	SP04	2018
Baghouse, SNCR, and FDA - Baghouse Bag Replacements	SP04	2018
Coal Handling System Maint. - Overhaul Barge Unloader - Chain, Buckets, Sprockets, Rollers, and Alignment	SP00	2018
Coal Handling System Maint. - Dredge River around Unloading Cells	SP00	2018
Mobile Equipment - No. 3 Scrapper Powertrain Rebuild	SP00	2018
Mobile Equipment - No. 10 Scrapper Powertrain Rebuild	SP00	2018
Ash System Maint. - Transfer Building (2) Outages	SP00	2018
Scrubber Maintenance - WESP SIRS Clean/Inspect/Repair	SP21	2018
Scrubber Maintenance - WESP SIRS Clean/Inspect/Repair	SP22	2018
Scrubber Maintenance - Replace Rubber Liner in "A" Scrubber Limestone Ball Mill	SP22	2018
Turbine Maintenance - Turbine Valves	SP02	2018
Turbine/Generator Overhaul	SP02	2018
Electrostatic Precipitator - Outage - Precipitator Inspection & Repairs	SP01	2018
Electrostatic Precipitator - Outage - Precipitator Inspection & Repairs	SP02	2018

Table 8.(2)(a)-12

Spurlock Power Station

Description	Operating Unit	Date
Baghouse, SNCR, & FDA - Inspect and Repair	SP03	2018
Baghouse, SNCR, & FDA - Inspect and Repair	SP04	2018
Baghouse, SNCR, and FDA - Baghouse Bag Replacements	SP04	2018
Coal Handling System Maint. - Overhaul Barge Unloader - Chain, Buckets, Sprockets, Rollers, and Alignment	SP00	2018
Coal Handling System Maint. - Dredge River around Unloading Cells	SP00	2018
Mobile Equipment - No. 3 Scrapper Powertrain Rebuild	SP00	2018
Mobile Equipment - No. 10 Scrapper Powertrain Rebuild	SP00	2018
Ash System Maint. - Transfer Building (2) Outages	SP00	2018
Scrubber Maintenance - WESP SIRS Clean/Inspect/Repair	SP21	2018
Scrubber Maintenance - WESP SIRS Clean/Inspect/Repair	SP22	2018
Scrubber Maintenance - Replace Rubber Liner in "A" Scrubber Limestone Ball Mill	SP22	2018
Turbine Maintenance - Turbine Valves	SP02	2018
Turbine/Generator Overhaul	SP02	2018

Table 8.(2)(a)-13

Spurlock Power Station

Description	Operating Unit	Date
Misc. Structure Maintenance - Day/Night Lighting Control	SP00	2019
Misc. Boiler Plant Maint. - Outage Boiler Inspection/Discovery Repair		2019
Misc. Structure Maintenance - HVAC	SP00	2019
Misc. Boiler Plant Maint. - Outage Boiler Inspection/Discovery Repair	SP01	2019
Mixc. Boiler Plant Maint . - Expansion Joint Repairs	SP01	2019
Misc. Boiler Plant Maint. - Overhaul Boiler Water Circulating Pump 2B	SP02	2019
Misc. Boiler Plant Maint. - Outage Boiler Inspection/Discovery Repair	SP02	2019
Misc. Boiler Plant Maint. - Expansion Joint Repairs	SP02	2019
Misc. Boiler Plant Maint. - 4A Feed Pump Volute Replacement	SP03	2019
Misc. Boiler Plant Maint. - Amstar Flame Spray Corner Maint.	SP03	2019
Misc. Boiler Plant Maint. - Outage Blr & Airheater Inspection & Repair		
Misc. Boiler Plant Maint. - Air Heater Baskets	SP03	2019
Misc. Boiler Plant Maint. - Outage Boiler & Airheater - Insp. & Repair	SP03	2019
Misc. Boiler Plant Maint. - Replace Air Preheater Components	SP04	2019
Boiler Pollution Control Equipment - Refractory	SP03	2019
Boiler Pollution Control Equipment - Refractory	SP04	2019
Boiler Pollution Control Equipment - Replace "C" Cyclone Target Wall	SP04	2019
Boiler Pollution Control Equipment - 4A & 4B Limestone Mills - Bull Rings	SP04	2019
Electrostatic Precipitator - Outage-Precipitator Inspection & Repairs	SP01	2019
Electrostatic Precipitator - Outage-Precipitator Inspection & Repairs	SP02	2019
Baghouse, SNCR, & FDA - Inspect and Repair	SP03	2019
Baghouse, SNCR, & FDA - Inspect and Repair	SP04	2019
Coal Handling System Maint. - Dredge River Around Unloading Cells	SP00	2019
Material Handling System - Replace Lower Slew Bearing on SR2	SP01	2019
Material Handling System - Replace PC1A Conveyor Belt	SP01	2019
Material Handling System - Replace Flights on SR2	SP01	2019
Material Handling System - Replace Flights on SR1	SP02	2019
Coal & Limestone Handling - Replace Cat Chain & Sprockets on SR3	SP03	2019
Coal & Limestone Handling - Replace Crusher Rotor	SP03	2019
Scrubber Maintenance - WESP SIRS Clean/Inspect/Repair	SP21	2019
Scrubber Maintenance - WESP SIRS Clean/Inspect/Repair	SP22	2019
Scrubber Maintenance - Replace Rubber Liner in "B" Scrubber Limestone Ball Mill	SP22	2019
Turbine Maintenance - Turbine Valves	SP01	2019
Turbine/Generator Overhaul - Unit No. 4 - 10-Year Turbine Overhaul	SP04	2019

Table 8.(2)(a)-14

Smith CTs - Station

Description	Operating Unit	Date
Generator Maintenance, Generator Inpection	SM05 and SM06	2015
Control System, Batteries - Units 4, 5, 6, and 7	SM4,5,6, & 7	2015
Control System Workstation - Purchase and Install - Units 1,2,&3	SM01,02,and 03	2015
Capital:		
New Landfill Site - Smith Phase 1 - Work Area A	SM00	2015
Turbine Control, New System for Unit No. 4	SM04	2015
Turbine Control, New System for Unit No. 5	SM05	2015
Structure, Paint Tank	SM00	2016
Structure, Smith Diesel Tank - API 653 Inspection	SM00	2016
Generator Maintenance, Generator Inspection	SM07	2016
Major Inspection Overhaul - Hot Gas Path	SM07	2016
Major Inspection Overahul - HPT Overhaul	SM10	2016
Stacks, Waterwash For CO Catalyst	SM09 and SM10	2016
Capital		
Turbine Control - New System	SM04	2016
Turbine Control - New System	SM05	2016
Turbine Control - New System	SM06	2016
Major Inspection Overhaul - Major Overhaul - Unit 1	SM01	2017
Structure, Paint Tank	SM00	2017
Major Inspection Overhaul - HPT Overhaul	SM09	2017
Capital		
Turbine Control - New System - Unit No. 6	SM06	2017
New Catalyst for Unit No. 9 and Unit No. 10	SM09 and SM10	2017
Turbine Control - New System - Unit No. 7	SM07	2017
Turbine Control - New System - Unit No. 1	SM01	2017

Table 8.(2)(a)-15

Smith CTs - Station

Description	Operating Unit	Date
Structure, Paint Tank	SM00	2018
Major Inspection Overhaul, Major Overhaul - Unit No. 2	SM02	2018
CI Inspection	SM04	2018
Capital		
Turbine Control - New System Unit No. 7	SM07	2018
Turbine Control - New System - Unit No. 1	SM01	2018
Turbine Control - New System - Unit No. 2	SM02	2018
Major Inspection Overhaul, Major Overhaul - Unit No. 3	SM03	2019
CI Inspection	SM05	2019
Capital		
Turbine Control - New System - Unit No. 2	SM02	2019
Turbine Control - New System - Unit No. 9 (Complete in 2020)	SM02	2019

SM00 - Smith Units Common
SM01 - Smith Unit 1
SM02 - Smith Unit 2
SM03 - Smith Unit 3
SM04 - Smith Unit 4
SM05 - Smith Unit 5
SM06 - Smith Unit 6
SM07 - Smith Unit 7
SM09 - Smith Unit 9
SM10 - Smith Unit 10

Table 8.(2)(a)-16

Landfill Gas

Description	Operating Unit	Date
Install 5th Unit at Pendleton (Capital)	Unit 5	2015
Green Valley - Engine Overhaul	Unit 2	2016
Laurel Ridge - Engine Overhaul	Unit 1	2016
Bavarian - Engine Overhaul	Unit 1	2016
Bavarian - Engine Overhaul	Unit 3	2016
Hardin - Engine Overhaul	Unit 1	2016
Pendleton - Engine Overhaul	Unit 3	2016
Green Valley - Engine Overhaul	Unit 1	2017
Green Valley - Engine Overhaul	Unit 3	2017
Laurel Ridge - Engine Overhaul	Unit 4	2017
Bavarian - Engine Overhaul	Unit 2	2017
Bavarian - Engine Overhaul	Unit 4	2017
Laurel Ridge - Engine Overhaul	Unit 3	2018
Laurel Ridge - Engine Overhaul	Unit 4	2018
Hardin - Engine Overhaul	Unit 2	2018
Hardin - Engine Overhaul	Unit 3	2018
Pendleton - Engine Overhaul	Unit 1	2019
Pendleton - Engine Overhaul	Unit 2	2019
Pendleton - Engine Overhaul	Unit 4	2019

Table 8.(2)(a)-17

Environmental

Description	Operating Unit	Date

At this time we do not have any items for 2015 - 2019

Table 8.(2)(a)-18

Construction (Capital)

Description	Operating Unit	Date
Spurlock NELG Compliance	SP00	2015
Smith Station Asset - Maintaining	SM00	2015
Cooper Unit No. 1 Duct Reroute	CP01	2015
Dale Decommisioning Phase One	DA00	2015
Dale Decommisioning Phase Two	DA00	2015
Spurlock - Physical Site Security	SP00	2015
Spurlock Landfill Area C - Phase Three	SP00	2015
Spurlock Aurora	SP00	2015
Peg's Hill Landfill	SP00	2015
Smith Aurora	SM00	2015
Smith Units 9 and 10 Oil Water Seperator	SM09 & SM10	2015
Cooper's Landfill - Purchase for Borrow	CP00	2015
Spurlock Landfill Final Cap - Area C - Phase One	SP00	2015
Cooper Landfill - Relocationof Transmission Line	CP00	2015
Cooper Landfill - Phase Two	CP00	2015
Glasgow Landfill		2015
Spurlock CCR Compliance	SP00	2015
Spurlock NELG Compliance	SP00	2016
Smith Station Asset - Maintain	SM00	2016
Cooper Unit No. 1 Duct Reroute	CP01	2016
Dale Decommisioning Phase One	DA00	2016
Dale Decommisioning Phase Two	DA00	2016
Spurlock - Physical Site Security	SP00	2016
Spurlock Landfill Area C - Phase Three	SP00	2016
Peg's Hill Landfill	SP00	2016
Smith Units 9 and 10 Oil Water Seperator	SM09 & SM10	2016
Cooper Landfill - Phase Two	C00	2016
Spurlock CCR Compliance	SP00	2016

Table 8.(2)(a)-19

Construction (Capital)

Description	Operating Unit	Date
Smith Station Asset - Maintain	SM00	2017
Spurlock Expansion of Area C Landfill - Phase Four	SP00	2017
Peg's Hill Landfill	SP00	2017
Spurlock NELG Compliance	SP00	2017
Spurlock CCR Compliance	SP00	2017
Dale Phase One Decommissioning	DA00	2017
Dale Phase Two Decommissioning	DA00	2017
Spurlock Expansion of Area C Landfill - Phase Four	SP00	2018
Peg's Hill Landfill	SP00	2018
Spurlock NELG Compliance	SP00	2018
Spurlock CCR Compliance	SP00	2018
Smith Station Asset - Maintain	SM00	2018
Peg's Hill Landfill	SP00	2019
Spurlock NELG Compliance	SP00	2019
Spurlock CCR Compliance	SP00	2019
Smith Station Asset - Maintain	SM00	2019

SECTION 8.0

INTEGRATED RESOURCE PLANNING

SECTION 8.0

INTEGRATED RESOURCE PLANNING

807 KAR 5:058 Section 5.(4) Summary of the utility's planned resource acquisitions including improvements in operating efficiency of existing facilities, demand-side programs, nonutility sources of generation, new power plants, transmission improvements, bulk power purchases and sales, and interconnections with other utilities.

807 KAR 5:058 Section 8(1) The plan shall include the utility's resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost. The plan shall consider the potential impacts of selected, key uncertainties and shall include assessment of potentially cost-effective resource options available to the utility.

807 KAR 5:058 Section 8.(2)(c) The utility shall describe and discuss all options considered for inclusion in the plan including: (c) Expansion of generating facilities, including assessment of economic opportunities for coordination with other utilities in constructing and operating new units.

807 KAR 5:058 Section 8.(2)(d) The utility shall describe and discuss all options considered for inclusion in the plan including: (d) Assessment of nonutility generation, including generating capacity provided by cogeneration, technologies relying on renewable resources, and other nonutility sources.

807 KAR 5:058 Section 8(3)(c) The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multistate integrated system shall submit the following information for its operations within Kentucky and for the multistate utility system of which it is a part. A utility which purchases fifty (50) percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases its energy needs. (c) Description of purchases, sales, or exchanges of electricity during the base year or which the utility expects to enter during any of the fifteen (15) forecast years of the plan.

807 KAR 5:058 Section 8(3)(d) The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multistate integrated system shall submit the following information for its operations within Kentucky and for the multistate utility system of which it is a part. A utility which purchases fifty (50) percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases

its energy needs. (d) Description of existing and projected amounts of electric energy and generating capacity from cogeneration, self-generation, technologies relying on renewable resources, and other nonutility sources available for purchase by the utility during the base year or during any of the fifteen (15) forecast years of the plan.

807 KAR 5:058 Section 8.(4)(a) 1-5 and 7-11 The utility shall describe and discuss its resource assessment and acquisition plan which shall consist of resource options which produce adequate and reliable means to meet annual and seasonal peak demands and total energy requirements identified in the base load forecast at the lowest possible cost. The utility shall provide the following information for the base year and for each year covered by the forecast: (a) On total resource capacity available at the winter and summer peak: 1. Forecast peak load; 2. Capacity from existing resources before consideration of retirements; 3. Capacity from planned utility-owned generating plant capacity additions; 4. Capacity available from firm purchases from other utilities; 5. Capacity available from firm purchases from nonutility sources of generation; 7. Committed capacity sales to wholesale customers coincident with peak; 8. Planned retirements; 9. Reserve requirements; 10. Capacity excess or deficit; 11. Capacity or reserve margin.

807 KAR 5:058 Section 8(4)(a)(6) The utility shall describe and discuss its resource assessment and acquisition plan which shall consist of resource options which produce adequate and reliable means to meet annual and seasonal peak demands and total energy requirements identified in the base load forecast at the lowest possible cost. The utility shall provide the following information for the base year and for each year covered by the forecast: (a) On total resource capacity available at the winter and summer peak. (6) On planned annual generation: Reductions or increases in peak demand from new conservation and load management or other demand-side programs.

807 KAR 5:058 Section 8(4)(b) 1-4 The utility shall describe and discuss its resource assessment and acquisition plan which shall consist of resource options which produce adequate and reliable means to meet annual and seasonal peak demands and total energy requirements identified in the base load forecast at the lowest possible cost. The utility shall provide the following information for the base year and for each year covered by the forecast: (b) On planned annual generation: (1) Total forecast firm energy requirements; (2) Energy from existing and planned utility generating resources disaggregated by primary fuel type; (3) Energy from firm purchases from other utilities; (4) Energy from firm purchases from nonutility sources of generation.

807 KAR 5:058 Section 8(4)(b)(5) On planned annual generation: 5. Reductions or increases in energy from new conservation and load management or other demand-side programs.

807 KAR 5:058 Section 8(4)(c) The utility shall describe and discuss its resource assessment and acquisition plan which shall consist of resource options which produce adequate and reliable means to meet annual and seasonal peak demands and total energy requirements

identified in the base load forecast at the lowest possible cost. The utility shall provide the following information for the base year and for each year covered by the forecast: (c) For each of the fifteen (15) years covered by the plan, the utility shall provide estimates of total energy input in primary fuels by fuel type and total generation by primary fuel type required to meet load. Primary fuels shall be organized by standard categories (coal, gas, etc.) and quantified on the basis of physical units (for example, barrels or tons) as well as in MMBtu.**

807 KAR 5:058 Section 8.(5)(a) The resource assessment and acquisition plan shall include a description and discussion of: (a) General methodological approach, models, data sets, and information used by the company.

807 KAR 5:058 Section 8(5)(b) The resource assessment and acquisition plan shall include a description and discussion of: (b) Key assumption and judgments used in the assessment and how uncertainties in those assumptions and judgments were incorporated into analyses.

807 KAR 5:058 Section 8.(5)(d) The resource assessment and acquisition plan shall include a description and discussion of: (d) Criteria used in determining the appropriate level of reliability and the required reserve or capacity margin, and discussion of how these determinations have influenced selection of options.

807 KAR 5:058 Section 8(5)(g) The resource assessment and acquisition plan shall include a description and discussion of: (g) Consideration given by the utility to market forces and competition in the development of the plan.

8.1 Introduction

EKPC's mission is to serve its member-owned cooperatives by safely delivering reliable and affordable energy and related services. One of its strategic objectives is to carefully manage its portfolio of assets and pursue diversity along two axes – one focused on the diversity of the supply resource (including DSM/EE programs) and one focused on the diversity of the ownership model. EKPC continually evaluates power supply alternatives based on the most recent load forecast projections, market expectations, cost criteria and financial data. Alternatives for supplying future resource needs are evaluated on a present worth of revenue requirements basis, as well as a cash flow basis. Any major power supply acquisition will generally be made via a Request for Proposals process ("RFP"). The RFP process ensures that EKPC has adequately surveyed available resources in the market for delivery to serve the EKPC load in a reliable and affordable manner.

8.2 Resource Planning Methodology Overview

EKPC develops a detailed load forecast every three years, with the most recent being completed in 2014. This forecast was approved by the EKPC Board of Directors in November, 2014, and was approved by Rural Utilities Service ("RUS") in March 2015. The load forecast was updated to reflect known conditions in 2014 and that data has been used in this IRP analysis.

Market and fuel prices are updated on a regular basis to ensure that current expectations are being modeled in the analysis. Based on this input data, then the DSM alternatives are evaluated utilizing the standard California tests. Based on those results, the load is modified to reflect the DSM analyses prior to developing the capacity expansion plan. Additionally, EKPC conducted an environmental assessment of its existing units and included those results in this analysis prior to performing the expansion analysis.

8.3 Load Requirements to be Served

The forecast indicates that for the period 2015 through 2029, total energy requirements will increase by 1.4 percent per year. Winter and summer net peak demand will increase by 1.0 percent and 1.5 percent, respectively. Annual load factor is projected to grow from 48 percent to 51 percent, which reflects the historical average. The DSM alternatives that were evaluated result in the following impacts on load:

Table 8.(4)(b)(5)

DSM Impacts
(New Programs)

Year	Impact on Energy Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	7,000	6	9
2016	16,152	14.1	20.2
2017	26,536	20.5	30.1
2018	67,134	31.4	40.3
2019	121,212	46.5	52.9
2020	192,681	65.5	65.9
2021	246,597	78.4	75.1
2022	290,724	88	82.8
2023	328,525	95.3	89.3
2024	362,816	102.5	95.3
2025	395,312	109.6	101
2026	426,559	116.7	106.5
2027	457,351	123.8	111.9
2028	487,053	130.8	117.1
2029	514,111	137.4	122.1

Details on the specific programs are provided in the Demand-Side Management - Technical Appendix.

8.4 Supply Side Optimization and Modeling

The primary model used in developing the resource plan was RTSim from Simtec, Inc., of Madison, WI. The RTSim production cost model calculates the hour-by-hour operation of the generation system including, unit hourly generation and commitment and power purchases and sales, including economy and day ahead transactions in the PJM energy market, and daily and monthly options. Generating unit input includes expected outages, Monte Carlo forced outages, unit ramp rates, and unit startup characteristics. The RTSim model uses a Monte Carlo simulation to capture the statistical variations of unit forced outages and deratings, load uncertainty, market price uncertainty, and fuel price uncertainty. Monte Carlo simulation requires repeated simulations (iterations) of the time period analyzed to simulate system operation under different outcomes of unit forced outages and deratings, load uncertainty, market price uncertainty, and fuel price uncertainty. The production cost model is simulating the actual operation of the power system in supplying the projected customer loads using a statistical range of inputs.

For this study, the model used the statistical load methodology. There is one set of load data in the model, which was created from the EKPC Load Forecast. Around this forecasted load, a range of distributions created four additional loads to define the high and low range of the potential loads to be examined. The model draws load data a few days at a time from the different forecasts (to represent weather patterns) to assemble the hourly loads to be simulated. Each iteration of the model draws a new load forecast to simulate. Actual and forecasted market prices, natural gas prices, coal prices, and emission costs are correlated to the load data used in the simulation. Five hundred (500) iterations are used in the model simulations.

RTSim's Resource Optimizer was used to perform the optimization of the resource plan. The Resource Optimizer automatically sets up and runs the RTSim production cost model to perform simulations of a large number of potential resource plans to determine the optimum plan. Because the basic RTSim model is used by the Resource Optimizer model, the Resource Optimizer uses the same data and detailed analysis that is used in the production cost model simulation, except that future units are set as resource alternatives. Any future resources to be considered by the Resource Optimizer are set up with several potential future commercial operation dates. The annualized fixed costs for capital are included along with the variable costs associated with a particular resource. Resources considered included:

REDACTED

Traditional Resources and PPAs

Table 8.(2)(c)

Resource	**Capacity Type**	**Capacity (MW)**	**Primary Fuel**	Projected Capital Cost (2015$) $/kW	$M
LMS100 CT	Peaking	97	Natural Gas	[redacted]	[redacted]
7EA CT	Peaking	98	Natural Gas	[redacted]	[redacted]
Combined Cycle	Peaking/Intermediate	400	Natural Gas	[redacted]	[redacted]
Combined Cycle	Peaking/Intermediate	200	Natural Gas	[redacted]	[redacted]
PPA - Market	Power Purchase	50	n/a	[redacted]	[redacted]
PPA - Market	Power Purchase	50	n/a	[redacted]	[redacted]
PPA - Market	Power Purchase	100	n/a	[redacted]	[redacted]
PPA - Market	Power Purchase	100	n/a	[redacted]	[redacted]
PPA - Market	Power Purchase	100	n/a	[redacted]	[redacted]
PPA - Emission Free	Power Purchase	50	wind	[redacted]	[redacted]
PPA - Emission Free	Power Purchase	50	wind	[redacted]	[redacted]
PPA - Emission Free	Power Purchase	50	wind	[redacted]	[redacted]
PPA - Emission Free	Power Purchase	50	wind	[redacted]	[redacted]

Renewable and Partnering Opportunities

EKPC is a member of the National Renewables Cooperative Organization (NRCO). NRCO offers cooperatives access to the necessary resources to thoroughly evaluate renewable energy projects without the expense of a dedicated staff. NRCO is active in the renewable energy marketplace on behalf of its members and customers, providing a centralized source of intelligence and opportunities. NRCO evaluates projects, presenting only the most promising to its members. NRCO facilitates transmission constraint modeling, Renewable Energy Credit market analysis, and engineering studies, and packages these into comprehensive recommendations. NRCO offers an established subscription process to participate in specific projects and can help members and customers with the ongoing operations and maintenance of those projects. By aggregating demand amongst multiple power supply cooperatives, NRCO offers developers a venue for efficiently reaching a larger and more diverse set of buyers. To date, EKPC has participated in the evaluation of out-of-state wind projects but has not found any that fit its generation expansion needs.

The Kentucky River lock and dam system is located throughout the EKPC/Member Cooperative service territory. EKPC has had discussions with developers who have the rights to develop hydro-generation facilities at these locations. In general, the evaluations of the electric power production potential from these proposed facilities show them not to be viable economically as a low cost form of energy production at this time.

EKPC currently has five landfill gas-to-energy (LFGTE) facilities and continues to strive to improve performance at each of these facilities. 2013 generation from the existing EKPC facilities was approximately 98,300 MWh up from 95,243 MWh in 2012 and 94,571 MWh in 2011. There are other LFGTE opportunities being investigated within the EKPC service territory and EKPC is currently working with Farmers RECC and the City of Glasgow, KY to develop the City of Glasgow Landfill into a LFGTE project. The project is expected to be on line in late 2015 and will produce an estimated 7,489 MWh each year.

In 2013 EKPC purchased 2,208 MWh from its one contracted cogeneration facility. Prominent barriers to new combined heat and power projects include large capital investment which many companies are not ready to make. These large investments require payback periods that may be long by their standards and these types of projects may not be directly related to the companies' main area of business. Currently EKPC is working with one small rural facility which plans to initially generate approximately 200 kW from a poultry digester methane recovery operation. There are no other combined heat and power or cogeneration projects planned within the EKPC service territory that EKPC is aware of.

EKPC, along with its sixteen member cooperatives, is currently investigating ways to finance small, down to 30 kW, solar photovoltaic projects in order to offer renewable solar energy to end users within the member cooperative's service territories. Tariffing methods including participation through EKPC's EnviroWatts program are being investigated.

There is currently approximately 300 kW of solar voltaic installations within the EKPC service territory taking advantage of the member cooperatives' net metering tariffs. This number continues to grow as solar voltaic prices continue to decrease. There are currently a few small wind turbine installations connected to the member cooperative's distribution network that are taking advantage of the net metering tariff. These combined add up to approximately 17 kW.

Energy from nonutility cogeneration for the next several years should remain flat at around 3500 MWh per year or less for the next several years. Load reduction due to net metering by member cooperative customers should remain at or less than 500 MWh per year for the next several years. Amendment 3 to EKPC's Wholesale Power Contract allows owner-members to serve some of their load outside the Wholesale Power Contract. EKPC's exposure to Amendment 3 resources is limited to 5% of EKPC's rolling three year peak load. Any third party supply arrangement must be presented to and approved by the EKPC Board of Directors under Board Policy 305. Currently there are 6 projects totaling almost 10 MW.

Resource Optimizer Results

Based on market conditions, price assumptions and resource options, the following expansion plan shown in Table 8.(4)(a)-1 prove to be the most economical solution for EKPC's future resource needs.

Table 8.(4)(a)-1
EKPC Projected Capacity Additions and Reserves
(MW)

Year	Other Cap.	Base Load Capacity Additions		Peaking/ Intermediate Cap. Additions		Total Capacity		Reserves		Reserve Margin	
		Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
2015						3,276	2,922	0	70	2.34%	19.28%
2016				150		3,326	2,672	0	70	3.13%	14.09%
2017				250		3,326	2,672	0	71	2.69%	12.93%
2018						3,326	2,672	0	72	2.34%	11.85%
2019						3,326	2,672	0	72	2.21%	11.19%
2020						3,326	2,672	0	73	1.99%	9.96%
2021						3,326	2,672	0	74	1.84%	8.93%
2022						3,326	2,672	0	74	1.65%	7.79%
2023						3,326	2,672	0	75	1.25%	6.71%
2024						3,326	2,672	0	76	0.67%	5.32%
2025						3,326	2,672	0	77	0.15%	4.09%
2026	50					3,376	2,722	0	78	0.87%	4.33%
2027						3,376	2,722	0	79	0.21%	3.22%
2028	50					3,426	2,772	0	80	0.82%	3.74%
2029	50					3,476	2,822	0	81	1.49%	4.40%

Notes:
Peaking/Intermediate Capacity additions are based on seasonal purchases that could be replaced by a purchase currently being negotiated with a third party based on EKPC's most recent RFP.
Other Capacity is composed of the following:
    50MWx 3 Renewable PPA

A minimum and maximum amount of capacity to be added by the model is specified to correspond to a specified reserve margin. The Resource Optimizer can simulate thousands of combinations of potential resources to determine the lowest cost plans. The new resources have to be simulated in operation with the current resources to determine the optimum expansion for the system. The lowest cost plans are determined from the present value of total production cost and annual fixed costs of future alternatives.

The Resource Optimizer constructs expansion plans to meet certain criteria, then simulates each plan and calculates the present value of each plan as compared to doing nothing. Some of the inputs needed by the Resource Optimizer are the minimum and maximum future capacity needs, resource alternatives, the annualized fixed cost of the resource alternatives, and the potential in-service dates for the alternatives. The resource alternatives are modeled with the same detail as the existing and committed units in the model. In development of this IRP, the Resource Optimizer was set to try up to 2500 unique expansion plans, with each of those simulated with 5 iterations. Each iteration varies loads, fuel and market prices, and forced outages. The Resource Optimizer was run for the time period 2015 through 2029. The results in the following table, Table 8.5(a)-1, show the five lowest cost plans out of 2500 plans simulated.

Table 8.5 (a)-1

DSM AFFECTED BASE RESOURCE OPTIMIZATION
Total tries: 2500
Top Cases with specific resource and in-service date

Case 1:		Case 4:	
Seasonal Purchase	1, 1,2016	Seasonal Purchase	1, 1,2015
Seasonal Purchase	1, 1,2016	Seasonal Purchase	1, 1,2016
Seasonal Purchase	1, 1,2017	Seasonal Purchase	1, 1,2017
Seasonal Purchase	1, 1,2017	Annual Purchase	1, 1,2017
Seasonal Purchase	1, 1,2017	Emission Free PPA	1, 1,2021
Emission Free PPA	1, 1,2026	Emission Free PPA	1, 1,2025
Emission Free PPA	1, 1,2028	Emission Free PPA	1, 1,2027
Emission Free PPA	1, 1,2029	Emission Free PPA	1, 1,2029
Case 2:		Case 5:	
Seasonal Purchase	1, 1,2016	Seasonal Purchase	1, 1,2016
Seasonal Purchase	1, 1,2016	Seasonal Purchase	1, 1,2016
Seasonal Purchase	1, 1,2017	Annual Purchase	6, 1,2016
Seasonal Purchase	1, 1,2018	Seasonal Purchase	1, 1,2018
Seasonal Purchase	1, 1,2019	Emission Free PPA	1, 1,2021
Emission Free PPA	1, 1,2026	Emission Free PPA	1, 1,2021
Emission Free PPA	1, 1,2028	Emission Free PPA	1, 1,2025
Emission Free PPA	1, 1,2029	Emission Free PPA	1, 1,2028
Case 3:			
Seasonal Purchase	1, 1,2016		
Seasonal Purchase	1, 1,2016		
Annual Purchase	1, 1,2017		
Seasonal Purchase	1, 1,2018		
Seasonal Purchase	1, 1,2020		
Emission Free PPA	1, 1,2020		
Emission Free PPA	1, 1,2021		
Emission Free PPA	1, 1,2029		

Table 8.(5)(a)-2
Resource Optimizer Plan Summary

Cumulative Min Cap	Incremental Cap	Year	Type	Plan 1	Plan 2	Plan 3	Plan 4	Plan 5	Final Plan
-71	0	2015	Base						
			RE PPA						
			Seasonal				100		
-25	46	2016	Base					100	
			RE PPA						
			Seasonal	150	200	200	100	200	**150**
270	294	2017	Base			100	100		
			RE PPA						
			Seasonal	250	50		50		**250**
575	305	2018	Base						
			RE PPA					50	
			Seasonal		50	50			
883	308	2019	Base						
			RE PPA						
			Seasonal		100				
1198	315	2020	Base						
			RE PPA			50			
			Seasonal			100			
1518	320	2021	Base						
			RE PPA			50	50	100	
			Seasonal						
1843	325	2022	Base						
			RE PPA						
			Seasonal						
2180	337	2023	Base						
			RE PPA						
			Seasonal						
2535	355	2024	Base						
			RE PPA						
			Seasonal						
2906	371	2025	Base				50	50	
			RE PPA						
			Seasonal						
3302	396	2026	Base						
			RE PPA	50	50				**50**
			Seasonal						
3718	416	2027	Base						
			RE PPA				50		
			Seasonal						
4162	444	2028	Base						
			RE PPA	50	50			50	**50**
			Seasonal						
4631	469	2029	Base						
			RE PPA	50	50	50	50		**50**
			Seasonal						

These five plans were reviewed to determine if the operation dates of the near term resources were in fact achievable based on recent experience.

Since market prices and natural gas prices are correlated to the load data, and the load data simulates various weather patterns including periods of high and low loads, the result is a robust simulation of a variety of load and market conditions. Risk analysis is thereby incorporated into the simulation.

8.5 Reliability Criteria and Projected Capacity Needs

As stated in Section 6, Transmission and Distribution Planning, EKPC is a member of SERC Reliability Corporation ("SERC"). SERC promotes the development of reliability and adequacy arrangements among the systems; participates in the establishment of reliability standards; administers a regional compliance and enforcement program; and provides a mechanism to resolve disputes on reliability issues. As a member of PJM and SERC, EKPC plans capacity to meet its capacity resource requirements defined by PJM plus being aligned to economically hedge its winter peak load expectations. See the table below for the total amount of capacity expected to be required on the EKPC system.

Table 8.(4)(a)-2
EKPC Projected Capacity Needs
(MW)

Year	Projected Peaks		3% Reserves		Total Requirements		Existing Resources		Capacity Needs	
	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
2015	3,201	2,324	0	70	3,201	2,394	3,276	2,922	-75	-378
2016	3,225	2,342	0	70	3,225	2,412	3,176	2,672	49	-260
2017	3,239	2,366	0	71	3,239	2,437	2,926	2,672	313	-235
2018	3,250	2,389	0	72	3,250	2,461	2,926	2,672	324	-211
2019	3,254	2,403	0	72	3,254	2,475	2,926	2,672	328	-197
2020	3,261	2,430	0	73	3,261	2,503	2,926	2,672	335	-169
2021	3,266	2,453	0	74	3,266	2,527	2,926	2,672	340	-145
2022	3,272	2,479	0	74	3,272	2,553	2,926	2,672	346	-119
2023	3,285	2,504	0	75	3,285	2,579	2,926	2,672	359	-93
2024	3,304	2,537	0	76	3,304	2,613	2,926	2,672	378	-59
2025	3,321	2,567	0	77	3,321	2,644	2,926	2,672	395	-28
2026	3,347	2,609	0	78	3,347	2,687	2,926	2,672	421	15
2027	3,369	2,637	0	79	3,369	2,716	2,926	2,672	443	44
2028	3,398	2,672	0	80	3,398	2,752	2,926	2,672	472	80
2029	3,425	2,703	0	81	3,425	2,784	2,926	2,672	499	112

Notes:
1. Reserve requirement updated to meet PJM Summer reserve requirement of 3%.
2. Existing Resources includes 170MW from SEPA throughout the period.
3. The impact of existing and new DSM programs is included in the load forecast.

Table 5.(4) below shows the expected capacity additions based on the 2015 IRP plan.

Table 5.(4)
EKPC Projected Major Capacity Additions
(MW)

Year	Baseload Capacity	Peaking/Intermediate Capacity	Cumulative Capacity Additions
2015			
2016		150	150
2017		250	400
2018			400
2019			400
2020			400
2021			400
2022			400
2023			400
2024			400
2025			400
2026		50 (renewable energy PPA)	450
2027			450
2028		50 (renewable energy PPA)	500
2029		50 (renewable energy PPA)	550

EKPC will work with Federal and State stakeholders to ensure the economic viability of future and existing resources to meet the challenges and opportunities surrounding climate change. EKPC is driven to use its assets to deliver reliable and affordable energy from appropriately diversified fuel sources. EKPC will carefully manage it portfolio of assets and pursue diversity of supply resources, including DSM/EE programs, market-based opportunities and risk related to climate change regulation/legislation. EKPC will continue to research and learn about related issues and opportunities.

Table 8.(3)(c)

Power Transactions (GWH)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Power Purchases	-	328	864	864	864	874	864	864	864	874	864	966	966	1,079	1,171
Market Purchase	2,021	2,306	2,413	3,342	2,911	3,490	3,403	4,453	4,667	4,939	5,236	5,471	5,343	5,605	5,149
SEPA	200	201	213	258	258	258	258	258	258	259	258	258	258	259	258
Total Purchases	2,221	2,835	3,490	4,464	4,032	4,622	4,525	5,575	5,789	6,071	6,357	6,695	6,567	6,943	6,577
Market Power Sales	269	177	164	152	157	98	107	79	70	53	55	29	46	44	32

Table 8.(3)(d)

Non-Utility Generation (GWH)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Non-Utility Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewables*	0	0	0	0	0	0	0	0	0	0	0	102	102	205	307

* Generation from landfill gas to energy projects are included in the response to 8.(3)(b) and 8.(4)(c).

In the next several years, approximately 3,500 MWh of energy per year will be supplied from cogeneration and 100,000 MWh of energy per year from LFGTE.

Table 8.(4)(b)1-4

Forecast Energy	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Requirements (GWh)	13,406.96	13,579.62	13,788.53	14,226.95	14,363.38	14,541.99	14,645.82	14,763.76	14,862.32	15,039.77	15,194.08	15,435.16	15,574.25	15,734.02	15,891.92
(as modeled)															
Generation (GWH)															
Coal	10,946.17	10,772.03	10,888.90	10,073.48	10,605.84	10,296.31	10,472.23	9,493.34	9,347.94	9,251.17	9,089.19	9,044.70	9,323.63	9,234.02	9,897.15
Natural Gas	611.9	581.0	553.6	866.0	907.1	756.4	780.4	798.8	819.3	804.9	827.5	851.1	856.3	841.1	781.4
Landfill Gas	97.1	97.4	97.1	97.1	97.1	97.4	97.1	97.1	97.1	97.4	97.1	97.1	97.1	97.4	97.1
Total	11,655.18	11,450.39	11,539.60	11,036.62	11,610.01	11,150.11	11,349.77	10,389.22	10,264.37	10,153.52	10,013.78	9,992.91	10,277.06	10,172.46	10,775.70
Purchases (GWH)															
Firm Purchases-SEPA	200	201	213	258	258	258	258	258	258	259	258	258	258	259	258
Firm Purchases-Other Utilities	0	328	864	864	864	874	864	864	864	874	864	966	966	1079	1171
Firm Purchases-Non-Utilities	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	200	529	1077	1122	1122	1132	1122	1122	1122	1132	1122	1224	1224	1337	1428

Table 8.(4)(c)

Fuel Input (1,000s MBTU)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Coal	110,355	108,359	109,239	101,075	106,419	103,438	105,190	95,650	94,233	93,315	91,731	91,337	94,074	93,312	99,838
Natural Gas	6,262	5,994	5,788	9,158	9,547	7,953	8,192	8,350	8,569	8,424	8,652	8,886	8,947	8,753	8,097
Total	116,617	114,353	115,026	110,233	115,966	111,392	113,382	104,000	102,801	101,739	100,383	100,223	103,021	102,065	107,935
Fuel Input (Physical Units)															
Coal (1,000s Tons)	4,832	4,751	4,794	4,439	4,677	4,549	4,624	4,211	4,149	4,109	4,040	4,022	4,141	4,107	4,389
Natural Gas (1,000s mcf)	6,172	5,907	5,704	9,026	9,409	7,839	8,074	8,230	8,445	8,303	8,528	8,758	8,818	8,627	7,980

807 KAR Section 8(3) The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multistate integrated system shall submit the following information for its operations within Kentucky and for the multistate utility system of which it is a part. A utility which purchases fifty (50) percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases its energy needs.

EKPC only operates within the state of Kentucky.

SECTION 9.0

COMPLIANCE PLANNING

SECTION 9.0

COMPLIANCE PLANNING

9.1 Introduction

Actions to be undertaken during the 15 years covered by the plan to meet the requirements of the Clean Air Act amendments of 1990 (CAA), and how these actions affect the utility's resources assessment.

EKPC is currently in compliance with the following CAA rules:

- New Source Performance Standards (NSPS);
- New Source Review (NSR);
- Title IV of the CAA and the rules governing pollutants that contribute to Acid Deposition (Acid Rain program);
- Title V operating permit requirements (Title V);
- Summer ozone trading program requirements promulgated after EPA action on Section 126 petitions and the Ozone SIP Call (Summer Ozone program);
- National Ambient Air Quality Standards (NAAQS) for Sulfur Dioxide (SO2), Nitrogen Dioxide (NO2), Carbon Monoxide (CO), Ozone, Particulate Matter (PM), Particulate Matter 2.5 microns or less (PM 2.5) and Lead;
- Clean Air Interstate Rule (CAIR) (Phased Out 12/31/14).
- Cross State Air Pollution Rule (CSAPR) (Effective 1/1/15)

On January 28, 2004, the United States filed a complaint alleging that EKPC was out of compliance with the Prevention of Significant Deterioration provisions in Part C of Subchapter I of the Act, 42 U.S.C. §§ 7470-92 (NSR); NSPS, Title V and the federally-enforceable State Implementation Plan ("SIP") developed by the Commonwealth of Kentucky. EKPC and the United States settled this action and entered into a Consent Decree memorializing the terms of the settlement which was entered by the Court on September 27, 2007 (NSR CD).

On June 30, 2006, the United States and the Commonwealth of Kentucky filed a complaint alleging that EKPC was in violation of the Acid Rain Program and Title V. This matter was also settled and the Consent Decree capturing the terms of the settlement was entered by the Court on November 30, 1997 (Acid Rain CD).

EKPC in partnership with the Environmental Protection Agency and the Kentucky Environmental Cabinet has worked diligently to implement the requirements of these two Consent Decrees and is in compliance with each. The relevant provisions of these CDs have been added to the Cooper and Dale Station Title V permits and have been added to the Spurlock Station Title V permit, but the revised permit is not final. EKPC fulfilled all of the covenants under the Acid Rain Consent Decree and EPA agreed to closeout.

NEW CAA RULES

Looking forward to the 15 years covered by this plan, EKPC anticipates complying with the following future rules or existing CAA rules that will generate future rules or requirements:

- Green House Gas (GHG) Tailoring Rule revisions to NSR, as modified by the Supreme Court in the 2014 decision in the UARG v. EPA case; ;
- Cross-State Air Pollution Rule (CSAPR);
- Electric Generating Unit Maximum Achievable Control Technology rule. EPA renamed this rule the Mercury and Air Toxics Standards (MATS) when the final rule was issued in December of 2011;
- Any revised National Ambient Air Quality Standards (NAAQS) for Sulfur Dioxide (SO_2), Nitrogen Dioxide (NO2), Carbon Monoxide (CO), Ozone, Particulate Matter (PM), Particulate Matter 2.5 microns or less (PM 2.5) and Lead;
- Clean Air Visibility (Regional Haze) rule to protect National Parks and pristine areas designated as Class I areas by EPA;
- Clean Power Plan.

I. EGU Mercury Air Toxics Rule

On March 16, 2011, EPA issued the proposed EGU MACT rule to reduce emissions of toxic air pollutants from new and existing coal- and oil-fired EGUs. EPA finalized the MATS rule on

December 16, 2011 to reduce emissions of heavy metals, including mercury (Hg), arsenic, chromium, and nickel, and acid gases, including hydrogen chloride (HCl) and hydrogen fluoride (HF). The MATS allows sources to control surrogate emissions to demonstrate control of HAP metals and HAP acid gases. Non-Hg metallic toxic air pollutants are represented by PM emission limits because these metals travel in particulate form in boiler gas paths. HCL and /or SO_2 are surrogates for all acid gas HAPs since they are controlled by the same mechanisms. Under MATS mercury emissions are subject to limits and units must measure mercury emissions directly to demonstrate compliance. EGUs must comply with the mercury, SO_2 or HCL, and PM limits in the MATS beginning in the spring of 2015. If units are in the process of installing additional pollution control equipment and cannot complete the work by this initial compliance date, an additional year to begin compliance can be granted by the Kentucky Cabinet. EKPC sought and received a MATs extension from KY DAQ for William C. Dale Units 3 and 4 and J.S. Cooper Station Units 1 and 2.

EKPC has conducted emissions testing of its units to determine the best way to achieve compliance with the MATS rule. This testing is ongoing and is being conducted as part of an extensive engineering effort to ensure that EKPC's units comply with this rule. The pollution control upgrades on Spurlock 1 and 2 and Cooper 2 as part of NSR CD compliance place EKPC's units ahead of most EGU units for MATS compliance. Likewise, EKPC's new units (Spurlock 3 and 4) are equipped with Best Available Control Technology (BACT) and are likely to meet the MATS rule limits without additional controls.

On November 25, 2014, the U.S. Supreme Court granted *certiorari* to an appeal of the MATS rule and will determine "whether the Environmental Protection Agency unreasonably refused to consider costs in determining whether it is appropriate to regulate hazardous air pollutants emitted by electric utilities." Oral argument was held on March 25, 2015.

II. <u>The Cross-State Air Pollution Rule</u>

On July 6, 2011 the EPA finalized CSAPR to require 27 states (Kentucky included) and the District of Columbia to significantly improve air quality by reducing power plant emissions that contribute to ozone and fine particle pollution in other states. This rule replaces EPA's 2005 CAIR rule that was remanded to EPA by the U.S. District Court of Appeals. CSAPR requires significant reductions in SO_2 and nitrogen oxides (NO_X) emissions that cross state lines. These pollutants react in the atmosphere to form fine particles and ground-level ozone and are transported long distances, making it difficult for other states to achieve the National Ambient Air Quality Standards (NAAQS). The rule called for the first phase emission reduction compliance to begin January 1, 2012 for annual SO_2 and NO_X and May 1, 2012 for ozone season NO_X. The second phase of SO_2 reductions was to begin January 1, 2014. On December 30, 2011, CSAPR was stayed by the United States Court of Appeals for the District of Columbia in response to industry petitions challenging the rule. On August 21, 2012, CSAPR was vacated and remanded back to EPA. EPA appealed this decision and on April 29, 2014, the Supreme Court reversed the United States Court of Appeals for the D.C. Circuit (D.C. Circuit) and reinstated CSAPR and remanded the rule back to the D.C. Circuit to determine next steps and resolve the many pending appeals of the rule that have not been acted on.

On June 26, 2014, the United States moved the D.C. Circuit to lift the stay on CSAPR but to toll the original compliance deadlines by three years. On October 23, 2014, the D.C. Circuit granted the motion and as a result, CSAPR was reinstated with Phase 1 beginning January 1, 2015 and Phase 2 will start on January 1, 2017. At this point only the dates have changed from the original program, everything else about the program is as it was in the fall of 2011 when preparations were underway to begin Phase 1 compliance.

III. <u>GHG Tailoring Rule</u>

On May 13, 2010, the EPA issued a final rule that established emission thresholds for addressing GHG emissions from stationary sources under the CAA permitting programs. The GHG Tailoring rule set GHG thresholds for applicability under the NSR rules and Title V program. GHGs are considered one pollutant for NSR, which is composed of the weighted aggregate of CO_2, N_2O, SF_6, HFCs, PFCs, and methane (CH_4) into a combined CO_2 equivalent (CO_{2e}).

Under the original GHG Tailoring rule, if any of the stations made a physical or operational change that would result in a net increase of 75,000 tons per year or more of CO_2 equivalents (CO_{2e}), EKPC must have obtained an NSR permit for the modification including the installation of Best Available Control Technology (BACT) for GHGs on the modified unit.

On June 23, 2014, the U.S. Supreme Court struck part of the GHG Tailoring Rule and held that a significant net emissions increase in GHGs alone cannot trigger NSR. NSR permitting requirements for GHGs can be triggered, but only if the physical or operational change also results in a significant net emissions increase of another PSD pollutant and that EPA has not yet set a significant emissions increase threshold for GHGs.

EKPC routinely analyzes all capital projects for the potential need to undergo pre-construction NSR permitting. This NSR review process has been expanded to include an analysis of GHG emissions. EKPC's NSR CD also includes a future covenant from EPA that allows EKPC some flexibility with respect to the NSR rules until December 31, 2015.

IV. National Ambient Air Quality Standards (NAAQS)

If a county or counties are designated to be in nonattainment for a NAAQS, the Cabinet will work with major sources contributing to nonattainment to implement Reasonably Achievable Control Technology (RACT) retrofits to bring the areas into attainment. Further, no permits can be approved by the Cabinet without a NAAQS compliance demonstration which involves submitting computer modeling of emissions that shows that the Commonwealth will stay in attainment despite the permitted activity.

A. CO

In January 2011, EPA proposed to retain the current primary CO NAAQS of 9 ppm (8-hour) and 35 ppm (1-hour). This rule was finalized in August 2011. As of September 27, 2010, all CO areas have been designated as maintenance areas. On April 11, 2014, the D.C. Circuit deferred to EPA's authority to set NAAQS, maintain the primary standard from 1971 and not set a secondary standard.

B. SO2

EPA revised the primary SO_2 NAAQS in June 2010 to a one-hour standard of 75 ppb. On June 2, 2011, Kentucky made area designation recommendations for the new SO_2 standard. The Commonwealth recommended that Jefferson County be designated as a non-attainment area and that the remainder of the Commonwealth be designated as unclassifiable or attainment. On October 4, 2013, EPA designated part of Campbell County, KY (together with part of Clermont County, OH) as non-attainment and part of Jefferson County, KY as non-attainment. The attainment demonstration deadline for both non-attainment areas is April 6, 2015. The current secondary 3-hour SO_2 standard is 0.5 ppm. EPA proposed to retain both the SO_2 and NO_2 secondary standards in July 2011 and this final rule was published on April 3, 2012.

On March 2, 2015, Sierra Club and EPA settled a lawsuit in the Northern District of California, Case No. 13-cv-0953-SI. Pursuant to the consent decree entered in that case, EPA will promulgate designations for the remaining areas of the country. Based on 2012 SO2 emissions, the consent decree identifies certain counties for which EPA must promulgate designations by July 2, 2016. Pulaski County, home to EKPC's Cooper Station, is included in the counties which must be designated in this initial phase. Kentucky must provide EPA with its recommendation by September 18, 2015. EKPC plans to provide Kentucky with updated emission data on Cooper to inform Kentucky's recommendation for Pulaski County. The consent decree requires EPA to promulgate designations for remainder of the country by 2017 or 2020.

C. NO2

EPA revised the primary NO_2 NAAQS in January 2010. The new primary NAAQS for NO_2 is a one-hour standard of 100 ppb. EPA retained the existing primary and secondary annual standard of 53 ppb. On January 11, 2011, Kentucky made area designation recommendations for the new NO_2 standard and recommended that areas with monitors showing compliance be designated as in attainment and that the remainder of the Commonwealth be designated as unclassifiable. On June 28, 2011, EPA responded indicating its intent to designate the entire country as unclassifiable/attainment due to the limited availability of monitoring data. On August 3, 2011, the Commonwealth responded to EPA's proposed revision requesting that the areas that show compliance with area monitors be designated as attainment and that the remainder of the Commonwealth be designated as unclassifiable/attainment. Final designation of the entire United States as unclassified/attainment was made on February 17, 2012. A new monitoring system will be implemented to measure NO_2 concentrations. EPA finalized a rule implementing a nation-wide monitoring on March 7, 2013 in two phases (2014 and 2017). Three years after the new monitoring system is implemented, EPA will re-evaluate the existing data and re-designate areas as necessary (2020). An initial compliance deadline of 2025 is contemplated. As mentioned above, in a final rule published on April 3, 2012, EPA retained the secondary NO_2 NAAQS of 0.053ppm averaged over a year.

D. Ozone

Currently, the primary 8-hour Ozone NAAQS is 75 ppb and the secondary 8-hour Ozone NAAQS is 84 ppb. The existing primary Ozone NAAQS standard was proposed by EPA in 2008 and at that time EPA proposed that the secondary Ozone NAAQS also be 75 ppb. EPA finalized the rule setting both the primary and secondary Ozone NAAQS at 75 ppb, and those standards were challenged in the D.C. Circuit Court of Appeals. In July 2013, the D.C. Circuit Court upheld the 2008 primary Ozone standard, but remanded the secondary standard to EPA. Therefore, the current primary Ozone NAAQS is the 2008 standard of 75 ppb and the current secondary Ozone NAAQS is the 1997 standard of 84 ppb. In December 2011, EPA revised the Commonwealth's recommendation and indicated its intent to designate Boone, Campbell and Kenton counties as non-attainment and the remainder of the Commonwealth as unclassifiable/attainment. Ultimately, the proposed final rule was withdrawn by EPA at the request of President Obama.

On December 23, 2014 the D.C. Circuit agreed with the NRDC that EPA cannot allow extensions of the NAAQS implementation deadlines which EPA did with the new Ozone NAAQS. On November 25, 2014, EPA proposed an update to the ground level ozone NAAQS. EPA's recent action proposes updating the primary and secondary ground level ozone NAAQS to be an 8-hour standard in the range of 65 to 70 ppb. EPA accepted comment on the appropriate primary and secondary limits, including what the limit should be, whether the existing limit should be retained and whether the primary (health) standard should be as low as 60 ppb. In calculating the secondary (public welfare) standard, EPA proposed using a two-step approach that involves defining a target level of protection and revising the standard to achieve that level of protection. EPA's initial analysis sets that limit in the range identified above, however the agency accepted comment on that as well.

In Kentucky counties with air monitors, 11[1] exceed a 70 ppb limit and an additional 12[2] counties exceed the more stringent 65 ppb limit. These projections are based on an average of the concentrations read by air monitors between 2011 and 2013.

EKPC has plants in three counties: Mason County (Spurlock Station); Clark County (Dale Station and Smith Station); and Pulaski County (Cooper Station). Of these three counties, only Pulaski County has an air monitor. Based on three years of data from 2011-2013, Pulaski County's ground level ozone concentration is 67 ppb. Pulaski would be in attainment if the ozone NAAQS is 70, but would exceed a 65 ppb NAAQS.

The public comment period closed on March 17, 2015, and EKPC timely submitted comments to EPA. EPA will hold three public hearings and expects to issue a final rule by October 1, 2015. EPA is subject to an order from the Northern District of California to sign a final rule by October 1, 2015.[3]

[1] The following Kentucky counties exceed a 70 ppb 8-hour ozone standard: Bullitt, Campbell, Daviess, Edmonson, Fayette, Hancock, Henderson, Jefferson, Livingston, McCracken and Oldham.

[2] The following Kentucky counties exceed a 65 ppb 8-hour ozone standard: Boone, Boyd, Carter, Christian, Greenup, Hardin, Jessamine, Morgan, Pulaski, Simpson, Trigg, Washington.

[3] On January 21, 2014, the Sierra Club, American Lung Association, Environmental Defense Fund and Natural Resources Defense Council sued EPA for not completing its review of the ozone standard by March 2013 (five years from the March 2008 update). The October 1, 2015 deadline resulted from that lawsuit.

E. Particulate Matter (PM2.5)

In 1997, EPA adopted the 24-hour fine particulate NAAQS ($PM_{2.5}$) of 65 $\mu g/m^3$ and an annual standard of 15 ug/m3. In 2006, EPA revised this standard to 35 $\mu g/m^3$, and retained the existing annual standard. In December 2004, the following counties were designated as nonattainment under the 1997 standard: Boone, Campbell, Kenton, Boyd, Lawrence (partial), Bullitt, and Jefferson. This was modified in April 2005 and in October of 2009, the entire Commonwealth of Kentucky was designated as unclassifiable/attainment under the 2006 standard.

EPA tightened the primary $PM_{2.5}$ NAAQS to 12 $\mu g/m^3$ on January 15, 2013. On January 15, 2015 EPA issued final PM $_{2.5}$ designations. EPA is now designating Boone, Campbell, Keaton, Bullitt and Jefferson counties as non-attainment.

F. Lead

In October 2008, EPA strengthened the primary lead NAAQS from 1.5 $\mu g/m^3$ to 0.15 $\mu g/m^3$. EPA has designated the Commonwealth of Kentucky as unclassifiable/attainment for the lead NAAQS. EPA retained this standard on December 19, 2014.

Currently, EKPC's units are not located in any areas that are predicted to be in nonattainment. EKPC anticipates that existing controls on its coal generation and new controls and compliance strategies adopted to comply with the MATS rule and CSAPR will ensure that the fleet will also comply with any future NAAQS requirements.

V. Regional Haze Rule

The Regional Haze Rule has triggered the first in a series of once-per-decade reviews of impacts on visibility at pristine areas such as national parks, with a focus in the first review on large emission sources put into operation between 1962 and 1977. This first review, just now being completed, targets Best Available Retrofit Technology (BART) controls for SO_2, NO_x, and PM emissions. The threshold for being exempt from BART review is very stringent, such that coal-fired electrical generating stations are almost universally subject to BART.

A BART assessment includes an evaluation of SO_2 controls and post-combustion NO_x controls. Cooper Units 1 and 2 are the only EKPC units subject to BART. EKPC has submitted its Regional Haze compliance plans to the Cabinet and the Cabinet submitted the plan for the Commonwealth to EPA who has proposed to adopt it formally into Kentucky's State Implementation Plan (SIP). EKPC installed SO_2, NOx and PM controls on Cooper 2 to comply with the NSR CD, the Regional Haze rule, MATS, CSAPR and any NAAQS requirements. EKPC has committed in the Regional Haze compliance plan to install parallel controls on Cooper 1 which is being accomplished currently through the Cooper Duct Re-route project.

VI. Clean Power Plan

EPA released the proposed Clean Power Plan (CPP) for existing EGUs on June 2, 2014, consistent with the President's Climate Action Plan. The proposal ultimately sets out CO_2 emissions rate goals (lbs/netMWhr) that each state must meet. These goals begin with an interim state lbs/netMWHr rate for EGUs that must be met over a ten year averaging period (glide path) from 2020-2029 and a final rate beginning 2030. EKPC notes that EPA is diverging from its practice in other air regulations (e.g., MATS[4]) of using gross not net generation for the calculation of emissions rates. The net CO_2 emissions rate goals are not only more difficult to meet, but also punitive for stations like the Spurlock station which has 154 MWs of auxiliary power, 45 percent of which is used for pollution controls.

EPA recognizes in the proposal that there is no technological option to reduce CO_2 emissions from power plants. Instead, EPA determines that the best system of emissions reduction (BSER) for CO_2 emissions from EGUs consists of two basic approaches that are made up of four "Building Blocks." The basic approaches are (1) reducing carbon intensity from individual fuel burning electric generating units and (2) reducing state CO_2 emissions rates by reducing utilization levels of coal, and forcing increased use of natural gas, nuclear and renewable sources through a series of unprecedented requirements clearly outside of EPA's authority under the Clean Air Act (CAA) or otherwise. Shifting generation away from coal, in the way that the CPP proposes, falls under the jurisdiction of the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), state legislatures, state public utility commissions and state environmental agencies, not EPA. The four Building Blocks are:

- Improving boiler efficiency by six percent (Building Block 1);
- Shifting electricity generation from existing baseload coal to existing natural gas combined cycle (NGCC) with a target of 70 percent capacity factor from existing NGCC (Building Block 2);
- Shifting generation to low-or zero-carbon generation by completing all nuclear generation currently under construction and somehow preventing the planned retirement of existing nuclear generation and increasing renewable energy (RE) generation (Building Block 3); and
- Increasing demand-side energy efficiency (EE) measures with a target of 1.5 percent in annual energy savings (Building Block 4).

[4] Mercury Air Toxics Standards

EPA applies these four factors to 2012 state-level data to calculate the interim and final lbs/netMWHr CO_2 emissions rate goals. Almost all of the CO_2 emissions rate goal reductions are calculated by assuming that the CPP will shift generation from existing coal plants to existing natural gas combined-cycle units, new RE generation and through aggressive demand-side EE projects. For Kentucky these calculations yielded

Interim Goal (2020-2029)	**Final Goal (2030)**
1,844 lbs/netMWh	**1,763 lbs/netMWh**

ADDITIONAL NON-CAA NEW RULES

For completeness EKPC is providing a summary of new Clean Water Act (CWA) rules and the proposed Coal Combustion Residuals (CCR) rule.

I. New CWA 316(b) Rule

A. Background

EPA published its final rule to regulate cooling water intake structures (CWIS) at existing facilities on August 15, 2014. The rule sets requirements that establish Best Technology Available (BTA) for minimizing adverse environmental impact from impingement mortality and entrainment mortality due to operation of CWIS. The rule became effective on October 14, 2014 and has been challenged in court by various parties. Unless the rule is stayed, EKPC must move forward with proposing to the Kentucky Division of Water how it will comply with BTA at its facilities with CWIS.

Impingement mortality (IM) results from impingement of aquatic organisms on the cooling water intake structure, typically traveling water screens used to prevent debris from entering the cooling water circulating pumps and the steam condenser tubes. Entrainment mortality (EM) results when organisms that are entrained through the cooling water intake structure die due to the combined effects of mechanical stress from the pumps, thermal stresses from the heat transferred from the condensers, and application of any biocides.

Spurlock Station, Cooper Station, and Dale Station are subject to requirements of Section 316(b) of the Clean Water Act (CWA) to minimize adverse environmental impact due to IM and EM at the respective cooling water intakes because each: (1) holds a Kentucky Pollutant Discharge Elimination System (KPDES) permit, (2) has a design intake capacity that withdraws more than 2 million gallons per day (MGD) from waters of the United States, and (3) withdraws at least 25 percent of the intake water for dedicated cooling purposes. EKPC's Smith Station is not subject to regulation under Section 316(b) as the combustion turbine generation does not use cooling water.

The IM performance standard established in the final rule is based on modified traveling screens with fish returns, and includes a compliance option based on survival rates after impingement as well as several alternative compliance approaches. In its rulemaking, EPA determined that there is no single technology that is BTA for EM. The final rule therefore contains a national BTA standard for EM that establishes a process by which the permitting authority (in Kentucky, the Division of Water) determines EM mitigation requirements on a site-specific basis

1. Impingement Mortality

As stated above, the final rule's IM performance standard is based on modified traveling screens with fish returns, but 40 CFR 125.94(c) includes several compliance alternatives. The alternatives are:

a. Closed-cycle recirculating system.
b. Design through-screen velocity $\leq$ 0.5 fps.
c. Actual through-screen velocity $\leq$ 0.5 fps.
d. Existing offshore velocity cap > 800 feet offshore.
e. Modified traveling screens with fish return.
f. A system of technologies and/or operational measures.
g. Compliance with numeric impingement mortality performance standard.

EPA described options a., b., and d. as "essentially" pre-approved technologies that require little if any demonstration for compliance. Options c., e., and f. were described as "streamlined" technologies that require monitoring and reporting requirements that ensure proper operation of the installed control technology. Option g. requires compliance with a numeric performance standard for IM. EPA does not anticipate that retrofit to closed-cycle cooling will be justified to mitigate IM alone. Each of these compliance alternatives has specific information submittal and monitoring requirements.

2. Entrainment Mortality

The rule requires the Director of the Division of Water to establish BTA for EM for EKPC's facilities on a site-specific basis that reflects the Director's determination of "the maximum reduction in entrainment warranted after consideration of the relevant factors..." (§125.94(d)). For facilities with actual intake flows (AIF[5]) greater than 125 MGD, the rule requires the submission of a number of reports that provide information to be used as the basis of the Director's decision on BTA for EM. Facilities with AIF less than 125 MGD are not required to perform these studies but are still subject to a BTA determination by the Director under §125.98(f).

EPA stated in the preamble to the final rule that "EPA is not implying or concluding that the 125 MGD threshold is an indicator that facilities withdrawing less than 125 MGD are (1) not causing any adverse impacts or (2) automatically qualify as meeting BTA". The Director has the discretion to still require some or all of these studies for facilities with an AIF less than 125 MGD "if there is reasonable concern regarding entrainment impacts."

As listed in §125.98(f)(2), a number of factors <u>must</u> be considered in the Director's determination, including:

- The number and types of organisms entrained, including federally-listed T&E species and/or critical habitat.

[5] AIF is the defined as the average rate of pumping by the facility over the last three years. AIF may account for days with zero flow. Five years after the effective date of the rule, the previous five years of record is used in calculating AIF.

- Impact of particulate emissions and other pollutants.
- Land availability for entrainment technology.
- Remaining useful life of the plant.
- Quantified and qualitative social costs and benefits.

Further, §125.98(f)(3) states that the Director may base the decision on the following factors "to the extent the applicant submitted information under 40 CFR 122.21(r):"

- Entrainment impacts on the waterbody.
- Thermal discharge impacts.
- Credit for flow reduction with unit retirement in the preceding 10 years.
- Impacts on reliability of energy delivery.
- Impacts on water consumption.
- Availability of water for reuse.

3. Information and Data Submittals

Section 122.21(r)(1)(ii) requires that all existing facilities with design intake flows of greater than 2 MGD submit to the Director information required under paragraphs (r)(2) and (3) and applicable provisions of paragraphs (4) through (8) Section 122.21 (r). For facilities with AIF greater than 125 MGD, the required additional studies include five additional reports described at §122.21(r)(9-13). The first is an entrainment characterization study (§122.21(r)(9)) with a minimum duration of two years. The entrainment study will support additional studies including a technical feasibility and cost study of entrainment mitigation measures (§122.21(r)(10)) which at minimum is to include closed-cycle cooling, fine mesh screens with a mesh size of 2 millimeters or smaller, and water reuse or alternate sources of cooling water. The Director may require evaluation of additional measures for entrainment mitigation. Additional studies include a Benefits Valuation Study (§122.21(r)(11)) and a Non-water Quality Environmental and Other Impacts Study (§122.21(r)(12)). Reports (10) through (12) require external peer review as provided by §122.21(r)(13). The reviewers are selected by the applicant and approved by the Director, and must have "appropriate qualifications". The applicant must provide an explanation for any "significant" reviewer comments that are not accepted.

The Director may reduce or waive some or all of the information required under paragraphs (r)(9) to (13) if the facility intends to comply with the BTA standards for entrainment using a closed-cycle recirculating system. The Director also has discretion to waive some of the submittal requirements under §122.21(r) if the intake is located in a manmade lake or reservoir and the fisheries are stocked and managed by a State or Federal natural resources agency or equivalent. Finally, existing facilities are required to submit any additional information deemed necessary by the NPDES director to determine permit conditions and requirements, potentially including information requested by the U.S. Fish & Wildlife Service (USFWS) and/or the National Marine Fisheries Service under §125.98(h).

As to the timing of the information submittals and determinations of IM and EM requirements, for facilities with pending NPDES renewal applications as of the rule's effective date that will result in a renewal permit being issued before July 2018, the information and studies required by §122.21(r) should not be due until the next NPDES Permit application is submitted (i.e., the next 5-year permitting cycle). However, the permitting authority has discretion to establish a schedule for submitting the information in the next renewal permit. Additional IM and EM controls, if any, would be generally determined by the agency in the next permitting cycle along with any necessary compliance schedule for designing and installing any necessary controls.

B. Potential Spurlock Station 316(b) Requirements

1. Spurlock Station Cooling Water System Description

The cooling system consists of four evaporative mechanical draft cooling towers with a combined makeup water requirement of 21.6 MGD. Spurlock Station withdraws water for cooling tower makeup and other purposes from the Ohio River. The station's CWIS consists of two submerged passive wedgewire intake screens, an intake sump, and three vertical makeup water pumps. The screens consist of welded Type 304 stainless steel wedgewire strainer elements with circumferential 1/8 inch slot construction. They each have a design capacity of 14,050 gallons per minute (gpm) and a maximum through-slot velocity 0.5 fps at design flow. The calculated velocity through the strainer elements is 0.466 fps. Debris collected in the screen is periodically cleaned by a compressed air backwash system which is capable of producing a backwash pressure of 150 pounds per square inch (psi).

Makeup water is withdrawn through the two submerged intake screens by gravity and flows into the intake sump. Each pump is rated for 5,000 gpm at 141.5 feet of head and is driven by a 250 hp/1.15 service factor, 1,180 rpm motor manufactured by General Electric. The cooling water intake structure does not employ traveling water screens.

2. Spurlock Station Compliance Options

Spurlock Station's passive wedgewire screens have a maximum design through-screen velocity of 0.5 fps; therefore, the intake screens should be considered BTA for IM under §125.94(c)(2). Spurlock Station's closed-cycle cooling system should also be considered BTA for IM under §125.94(c)(1).

Spurlock Station utilizes a closed-cycle recirculating cooling system with maximum makeup water demand of 21.6 MGD, which is substantially under the rule's AIF threshold of 125 MGD that would subject it to the rule's requirement for comprehensive entrainment studies. As discussed above, facilities with AIF less than 125 MGD are not required to perform the entrainment studies required under §§122.21(r)(9) through (13) but are still subject to a BTA determination by the Director under §125.98(f).

An additional factor that could impact the expectation that no additional controls will be required for IM or EM at Spurlock Station is whether there are potential issues with federally-listed threatened or endangered (T&E) species or designated critical habitat. A recent review of listed species in the vicinity of the Spurlock Station intake indicated two federally-listed endangered mussel species that may be present in the source waterbody, the fanshell (Cyprogenia stegaria) and the sheepnose (Plethobasus cyphyus). Of the two, the sheepnose is more likely to be present as it is known to occur within the Ohio River. There are no critical habitat designations in the adjacent segment of the Ohio River near Spurlock Station. With regard to T&E species, the Director, in consultation with the Services, determines additional control measures that may be required "to minimize incidental take, reduce or remove more than minor detrimental effects to federally-listed species and designated critical habitat, or avoid jeopardizing federally-listed species or destroying or adversely modifying designated critical habitat" under §125.94(g). At this point in time, EKPC is unaware of any potential impacts to T&E species.

Spurlock Station's KPDES permit has been administratively continued and a renewal application has been pending since prior to the rule's effective date. It is uncertain when the permit will be reissued, but it is anticipated it will be issued within the next 12 to 15 months. Submittals required under sections 122.21(r)(2)-(8) will therefore need to be included with the next KPDES renewal application per §125.95(a)(1) in approximately 5 years. The final rule contains no explicit supplemental information requirements for administratively continued permits; however, §125.98(g) allows the Director of the Division of Water to ask for additional information to support the current renewal application. The final BTA determinations for IM and EM should be confirmed by the Division of Water in the KPDES renewal permit issued at that time (approximately 2021). Alternatively, §125.98(g) authorizes the Division of Water to make those determinations in the upcoming renewal permit if it finds the record supports findings that the cooling tower use meets IM and EM standards.

C. <u>Potential Cooper Station 316(b) Requirements</u>

1. Cooper Station Cooling Water System Description

The cooling system at the Cooper Station consists of two condensers equipped with once-through cooling systems. The permanent intake structures are located in Lake Cumberland approximately 25 feet from the shoreline and withdraw water at an elevation of 671 feet mean sea level (MSL), which under full pool conditions (723 feet MSL) is approximately 52 feet below the water surface.

The once-through cooling water system at Cooper Station has a design intake flow of approximately 208 MGD. Unit 1's intake has a design capacity of 89.2 MGD and consists of two 42-inch intake pipes, two hydraulic turbine pumps to lift water to the elevated screen house, two conventional traveling screens, two 32,000 gallon per minute (gpm) circulating water pumps, and a fish return system. The conventional traveling screens are 10 feet wide, have 3/8-inch screen openings, and a minimum maintained wetted screen depth of 30 feet. The estimated through-screen velocity at design flow is 0.34 fps. The estimated velocity at the two 42 inch intakes located in the lake at design flow is 7.2 fps.

Unit 2's intake has a design capacity of 118.9 MGD and consists of two 48-inch intake pipes, two hydraulic turbine pumps to lift water to the elevated screen house, two conventional traveling screens, two 40,000 gpm circulating water pumps, and a fish return system. The traveling screens are 10 feet wide, have 3/8-inch screen openings, and a minimum maintained wetted screen depth of 30 feet. The estimated through-screen velocity at design flow is 0.45 fps. The estimated through-pipe velocity at the two 48 inch intakes located in the lake at design flow is 7.3 fps.

An 8-cell cooling tower was also retrofitted to Unit 2 in 2007 and brought online in 2009, and was operated during warm water months to offset the elevated intake temperatures at the surface due to the lower lake levels that existed while Wolf Creek Dam was being repaired. When operating, the cooling tower has an average makeup water demand of 3.25 MGD, substantially reducing the cooling water supply requirement for Unit 2 and the overall demand for the station. The estimated through-pipe velocity at the Unit 2 intakes drops to 0.2 fps during cooling tower operation and the through-screen velocity drops to an estimated 0.012 fps.

The traveling screens are typically manually operated twice per day but may operate more frequently when the debris loads are high and increased differential pressure across the screens triggers automatic operation. Fish and debris are washed into a trough below the traveling screens and then conveyed through a pipe which releases fish back into the lake.

2. Cooper Station Compliance Options

The calculated through-screen velocities are less than the 0.5 fps threshold; therefore based on the rule's definitions the existing screens should be considered BTA for impingement mortality as a pre-approved technology under §125.94(c)(2). EKPC should only need to demonstrate that the screen design results in a through-screen velocity that does not exceed the 0.5 fps threshold under minimum water levels and maximum head differential. At Cooper Station, water level in the elevated wet wells for both intakes is independent of the lake level; therefore, the minimum maintained wetted screen depth of 30 feet would be used in the demonstration of compliance of the intake design. The final rule deleted requirements for facilities to deploy technologies to avoid entrapment but required that entrapped organisms be included as impingement mortality. The Director may use his or her discretion to require additional controls if entrapment is considered to be a substantial concern.

While there are no biological compliance monitoring requirements for pre-approved technologies and no requirement to meet specific reductions in impingement mortality due to entrapment, the rule does specifically prohibit take of threatened or endangered species. Based on available information, there are no federally-listed species known to occur within Lake Cumberland near Cooper Station that would be susceptible to effects due to impingement or entrainment.

Cooper Station's design capacity of 223 MGD could potentially result in an AIF that exceeds the rule's 125 MGD threshold that would subject it to the requirement for an entrainment characterization study. However, several circumstances have resulted in an AIF of less than 100 MGD for the last three years, including:

- Low capacity factor for Unit 1 (approximately 30 percent).
- The units operate on one pump only from December through March when lake water temperatures are low.
- Operation of the Unit 2 cooling towers prior to return to normal lake levels in 2013.

EKPC has estimated that without seasonal operation of the Unit 2 cooling towers the combined flow reduction from the low Unit 1 capacity factor and winter operations on one circulating pump would potentially yield an AIF of approximately 155 MGD. Cooper Station will need to closely examine its ability to remain below the 125 MGD threshold (with or without including the Unit 2 cooling tower as part of the flow reduction strategy) to avoid being categorically included in the rule's requirement to submit reports for entrainment BTA under §§122.21(r)(9) through (13). Otherwise, EKPC would need to undertake extensive entrainment studies of the

CWIS impacts of both Units 1 and 2. EKPC will evaluate the costs and other aspects of either seasonal or periodic operation of the Unit 2 cooling towers as a potential compliance option to remain below the 125 MGD threshold.

Even if Cooper Station can maintain flows below the 125 MGD threshold, facilities with an AIF less than 125 MGD are still subject to an entrainment BTA determination by the Director under §125.98(f) where the Director must determine "the maximum reduction in entrainment warranted after consideration of factors relevant for determining the best technology available for minimizing adverse environmental impact at each facility".

The factors which the Director must/may consider in the BPJ decision are listed above, with the Director given discretion as to the relative weighting of each factor. First and foremost amongst the factors is consideration of the numbers and types of organisms entrained (including federally-listed T&E species and designated critical habitat). With no current/known potential for impacts to T&E species, EKPC believes the Director would likely focus on the numbers and types of organisms entrained, for which existing site-specific data are not available.

This data gap may be filled through a literature search on the life history of the fish community present in Lake Cumberland, and in particular the periods of peak reproductive activity and the distribution of early life stages in the water column. This information, along with the absence of federally-listed T&E species, would constitute an important component of the Baseline Biological Characterization to be submitted under §122.21(r)(4). Using available biological data, EKPC plans to evaluate whether the location of the submerged intake at a depth of 52 feet minimizes the potential for entrainment of these early life stages, and supports a determination by the Director that additional measures to reduce EM (such as use of the existing Unit 2 cooling towers) are not warranted.

Cooper Station will need to submit the information outlined in §§122.21(r)(2)-(8) unless the Director uses his authority under §125.95(a)(3) to waive some or all of the §122.21(r) reports in a "manmade lake or reservoir" with "fisheries [that] are stocked and managed by a State or Federal natural resources agency or equivalent." This provision could potentially apply since

Lake Cumberland has no federally-listed T&E species and is currently stocked by the Kentucky Department of Fish and Wildlife Resources with walleye and striped bass, is considering stocking of shell cracker, and is implementing a recovery program to reintroduce lake sturgeon.

EKPC will need to discuss the basis of its selected IM compliance approach based on maximum design through-screen velocity less than 0.5 fps in the submittal for §122.21(r)(6). As previously discussed, the summary of the biological resources in the source water under §122.21(r)(4) will be important to provide the basis for the determination of EM BTA and gain concurrence by the Services.

Cooper Station's KPDES permit expired in October 2013 and, similar to Spurlock Station's permit, has been administratively continued and a renewal application is pending. A reissued KPDES Permit is expected within the next 12 to 15 months. Therefore, data/study submittals required under §§122.21(r)(2)-(8) will need to be included with the next NPDES renewal application per §125.95(a)(1) (approximately 2020). The final rule contains no explicit supplemental information requirements for administratively continued permits; however, the NPDES Director may ask for additional information to support the current renewal application. Compliance for IM following the pre-approved 0.5 fps intake design through-screen velocity will eliminate the need for IM monitoring requirements following the Director's decision on IM BTA.

The applicable monitoring provisions for entrainment will vary with the determination of whether Cooper Station's AIF is less than or greater than 125 MGD. If greater than 125 MGD, a two-year entrainment characterization study will need to be implemented and included with the reports required under §§122.21(r)(9)-(13). Beyond this initial two year period, the rule provides the Director the discretion to determine the monitoring frequency, including for potential monitoring that occurs after the EM BTA finding. The rule allows, but does not require post-entrainment mortality monitoring. It is likely that such a mortality assessment would not be beneficial to the overall assessment strategy and compliance approach.

D. Potential Dale Station 316(b) Requirements

1. Dale Station Cooling Water System Description

The cooling system at the Dale Power Station consists of once-through cooling systems using water withdrawn from the east bank of the Kentucky River at river mile 177.5. The CWIS has a total design capacity of 219 MGD and consists of a stop log and trash rack structure, a screen well, six traveling screens, and six circulating water pumps. The trash rack is located at the river bank, while the traveling screens are located approximately 500 feet from the bank. River water is withdrawn through the stop log and trash rack structure into two 72-in diameter pipes at an intake invert elevation of 557 feet mean sea level (MSL). Based on available river profiles from the U.S. Army Corps of Engineers (USACE) Louisville District, the normal pool elevation at this point in the Kentucky River (Pool 10) is approximately 567.6 feet MSL. This normal pool elevation results in a typical water depth at the inlets of approximately 10 feet. The pipes convey river water into the screen well at the screen house structure. The screen house structure contains the screen well, traveling screens, and circulating water pumps for all four operating units. Two screens with respective pumps provide cooling water for Units 1 and 2. The remaining four screens and pumps provide cooling water for Units 3 and 4. The conventional traveling screens have 3/8-inch mesh, a wetted depth of 13 feet, and are equipped with high-pressure washes and troughs that flow into an open channel that flows back into the river.

Units 1 and 2 circulating water pumps have a capacity of 22,000 gpm (31.7 MGD) each. Based on a screen width of 4 feet, 13-foot wetted depth, and a 68 percent open area, the estimated through-screen velocity for Units 1 and 2 is 1.39 feet per second (fps). Unit 3 and 4 circulating water pumps each have a capacity of 27,000 gpm (38.9 MGD). Based on a screen width of 9 feet, 13-foot wetted depth, and a 68 percent open area, the estimated through-screen velocity is 0.76 fps.

The circulating water pumps for Units 1 and 2 operate when the units are in operation. Since they discharge to a common header, either pump can be used when only one unit is operating. If both screens are used when only one unit is operating, the through-screen velocity is halved (approximately 0.7 fps). The four circulating water pumps for Units 3 and 4 also discharge to a common header, and all four pumps are typically used for approximately six months of the year. During the colder months of the year, three pumps are sufficient to meet the heat rejection requirements for Units 3 and 4, resulting in a 25 percent reduction in flow across the four traveling screens serving Units 3 and 4 and a through-screen velocity of 0.57 fps. The screens are operated automatically based on head-loss triggers and typically rotate two hours per day. During periods when debris loads are high the screens may operate continuously. A trough below each traveling screen conveys fish and debris washed from the screens into a pipe which leads from the screenhouse to a trough which returns fish to the Kentucky River through an open, rip-rap lined channel.

2. Dale Station Compliance Options

In a press release on April 11, 2014 EKPC announced it intends to deactivate Dale Station, closing Units 1 and 2 "immediately" and placing Units 3 and 4 in inactive status by April 2015. EKPC requested an extension under the Mercury and Air Toxics Standards (MATS) rule that goes into to effect in April 2015 to allow Units 3 and 4 to operate until April 2016. That request was approved by the Kentucky Division for Air Quality by letter dated January 6, 2015. An additional one-year extension beyond April 2016 may be feasible if a federal compliance order is obtained.

As noted above, Dale's current KPDES Permit has been administratively continued and a renewal application is pending. Given that final IM and EM determinations would not be required until after the next KPDES renewal application is submitted, operations at Dale are expected to cease before the IM and EM compliance deadlines. While it is unlikely that the Director would request additional information to support the current renewal application, there is the potential that the Director may request current information on federally-listed threatened and endangered species and/or critical habitat in the vicinity of the intakes. A recent review of listed species in the vicinity of the Dale Station intake indicated no federally-listed aquatic species subject to protection under the ESA, and no critical habitat designations in the adjacent segment of the Kentucky River.

II. Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category

A. Background

On June 7, 2013, EPA published its proposed effluent limitation guidelines (ELGs) for the steam electric power generating point source category. The ELGs, when final, will establish revised technology-based effluent limitations and standards for various wastewater streams generated by fossil fuel-fired steam electric generating stations. The ELGs will establish the best available technology economically achievable (BAT) requirements for existing facilities, including Spurlock Station, Cooper Station, and Dale Station.

In the proposed rule, EPA set forth the wastewater treatment options that were under consideration for various wastewater streams generated by coal-fired power plants. That includes flue gas desulfurization (FGD) wastewater, fly ash transport water, bottom ash transport water, coal combustion residual (CCR) landfill leachate, non-chemical metal cleaning wastes, and wastewater from flue gas mercury control systems. EPA has proposed effluent limitation standards based upon four combinations of treatment options for existing sources. Some of the treatment options for specific wastestreams (e.g., landfill leachate) are the same under several or all preferred options.

EPA expects to promulgate the final ELGs in September 2015. In the proposal, EPA expected that NPDES Permits issued in the next permitting cycle beginning three years from the effective date of the rule would contain a compliance schedule for any newly established ELGs. The compliance schedules would be set by the state NPDES permitting authority (e.g., Division of Water in Kentucky). At the time of the proposed rule, EPA anticipated that the rule would be finalized in June 2014, but issuance of the final rule has been delayed a year and is now expected by September 2015. Accordingly, it is anticipated that any new wastewater controls required to be installed to meet the new ELGs would need to be constructed and operational within no more than eight years form the effective date of the final rule, depending on circumstances. EPA determined that compliance schedules are necessary to accommodate studies of available technologies and operational measures, and subsequent design and installation of the wastewater control technologies at each facility.

B. Potential ELG Requirements for Spurlock Station

Wastewaters at Spurlock Station are generated from several sources, including ash transport waters, ash pond overflow, low volume waste, coal pile runoff, cooling tower blowdown, FGD scrubber blowdown, metal cleaning wastes, and stormwater. The ash pond receives clarifier solids and other wastewaters from the pretreatment area and boiler bottom ash water in addition to effluent from the material handling storage pond. Flows from the primary lagoon and ash pond are directed to the secondary lagoon, along with FGD scrubber blowdown from FGD Units 1 and 2. Cooling tower blowdown can be directed to either the primary or secondary lagoons. Chemical precipitation is used to treat chemical metal cleaning wastes.

Under EPA's proposal, it appears likely that FGD wastewater would be subject to effluent limitations for certain metals, including mercury, arsenic, and potentially selenium. It is likely that EKPC would need to design and construct a physical/chemical precipitation treatment plant, and potentially an additional biological treatment unit, to meet the proposed permit limits. Note that a physical-chemical wastewater treatment system to treat metals prior to discharge into the ash pond may also be required to meet future water quality-based effluent limitations in the renewed KPDES Permit for the facility.

Under all proposed options, dry handling would be required for fly ash. Therefore, dry handling and disposal of fly ash in the on-site currently permitted landfill will likely be required under the final rule. The facility already provides for dry handling of fly ash. However, treatment of bottom ash transport water in impoundments may remain authorized under the final rule. If EPA requires dry handling of bottom ash in the final rule, the current ash pond could no longer be utilized for bottom ash storage or disposal with the phase-out period being established by a compliance schedule in a future KPDES Permit. Continued use and operation of the ash pond at Spurlock Station will also be impacted by the final CCR disposal rule published on December 19, 2014, as discussed elsewhere in this submittal. With respect to CCR leachate, all preferred options would allow use of impoundments for treatment to achieve effluent limitations established for total suspended solids, and oil and grease. No significant changes in operation would be expected to comply with the proposed requirements for CCR leachate.

It is unclear whether any changes in methods of operation would be required to comply with the final ELGs with respect to non-chemical metal cleaning wastes. EPA has proposed to continue exemptions from copper and iron limitations for certain non-chemical metal cleaning wastes consistent with exemptions that exist under current NPDES Permits. The Kentucky Division of Water has authorized such exemptions in the current KPDES Permit for Spurlock Station.

C. Potential ELG Requirements for Cooper Station

Wastewaters at Cooper Station are generated from several sources and include once-through cooling water, cooling tower blowdown, metal cleaning wastes, coal pile runoff, CCR landfill leachate, and stormwater. As noted above, a renewal application for a KPDES Permit is pending for Cooper Station and a renewed KPDES Permit is expected in approximately 12 to 15 months.

Cooper Station already utilizes dry handling for fly ash and bottom ash and, therefore, no impacts on these activities are expected from the final ELGs. Similarly, Cooper Station already employs sedimentation through an impoundment for treatment of CCR leachate from the landfill, so no impacts are expected from the ELG unless more stringent standards are adopted in the final rule. Cooper Station does not operate a wet FGD.

Depending on the requirements of the final rule with respect to non-chemical metal cleaning wastes, the final rule could have some impact on the manner in which such wastewater streams are handled. However, the potential exists for continuation of the same exemption that exists under the current KPDES Permit for non-chemical metal cleaning wastes, which are discharged to the coal pile runoff pond and are treated in a physical chemical wastewater treatment plant prior to being discharged.

D. Potential ELG Requirements for Dale Station

Wastewaters at Dale Station are generated from several sources and include once-through cooling water, metal cleaning wastes, fly ash and bottom ash, transport wastewater, coal pile runoff, low volume waste, and stormwater. A renewal KPDES Permit application is pending for Dale Station and a revised KPDES Permit could be issued within the next 12 months. However, in light of the fact that none of the coal-fired units at Dale Station will likely operate beyond April 2016, it is likely that any compliance deadline under the ELG for conversion to dry handling for fly ash and bottom ash would be after cessation of operations. If those plans change, however, it is likely the facility would need to convert to dry handling for fly ash and bottom ash. As discussed elsewhere in this submittal, EKPC has developed a plan for removal of coal ash in the ash ponds at Dale Station and transport to the new CCR landfill being constructed at Smith Station. Therefore, it is likely that the ash ponds would be removed and closed prior to any ELG compliance deadline.

III. New CCR Rule

On June 21, 2010, EPA published the Proposed Rule for Disposal of Coal Combustion Residuals (CCRs) from Electric Utilities. EPA provided two co-proposals for public comment: regulation of CCRs as a hazardous, or "special," waste under RCRA subtitle C and regulation of CCRs as a solid waste under RCRA subtitle D. EPA stated that it supports and has endeavored to maintain beneficial reuse of CCRs under both proposed rules. The Subtitle C alternative has extensive repercussions and there are serious questions as to whether the industry could comply with these requirements.

EPA issued the final CCR rule on December 19, 2014. In its final rule, EPA determined that CCR is a solid waste, not a hazardous waste. The final rule applies to owners and operators of new and existing landfills and new and existing surface impoundments, including all lateral expansions of landfills and surface impoundments where CCR is disposed (together, CCR units). The rule also applies to some inactive CCR surface impoundments (units no longer receiving

CCR after the rule is effective) at active electric utilities, if the unit still contains CCR and liquids. CCR includes fly ash, bottom ash, boiler slag and flue gas desulfurization materials.

The requirements in the final rule do not apply to (1) CCR landfills that ceased receiving CCR prior to the effective date of the rule; (2) CCR units at facilities that have ceased producing electricity prior to the rule being effective; (3) CCR generated at facilities that are not part of an electric utility or independent power producer, such as manufacturing facilities, universities and hospitals; (4) fly ash, bottom ash, boiler slag, and flue gas desulfurization generated primarily from the combustion of fuels other than coal (unless the fuel burned consists of more than fifty percent coal on a total heat input or mass input basis, whichever results in the greater mass feed rate of coal; (5) CCR that is beneficially used; (6) CCR placement at active or abandoned underground or surface coal mines; or (7) municipal solid waste landfills that receive CCR.

The rule will be effective six months after publication. The rule has not been published in the Federal Register yet. Certain requirements that need additional time to implement have later deadlines. The key components of the final rule are outlined below.

- Reducing Risk of Catastrophic Failure
  - Structural Integrity Requirements
- Protecting Groundwater
  - Groundwater Monitoring and Corrective Action
  - Location Restrictions
  - Liner Design Criteria
- Operating Criteria
- Record Keeping, Notification, and Internet Posting
- Inactive Units
- State Programs
- Closure
- Beneficial Use.

EKPC is actively developing legal and technical analysis in order to produce an environmental compliance plan for the new CCR rule.

Stakeholder Collaboration

EKPC routinely engages the Kentucky Environmental and Energy Cabinet and reporting agencies, namely, the Division of Air, Water, Waste and Public Service Commission. EKPC works and strives to routinely engage the Cabinet to ensure regulatory interpretation and understanding of direction as each pending EPA rule becomes published. EKPC values the Cabinet and its agencies. EKPC views the Cabinet as an integral part of our team.

Going forward, EKPC will have open dialogue with the Cabinet as stakeholders about each of the newly proposed EPA rules for the rules do affect decisions for the Owner-Members and company. The new rules impact our existing coal-fired and natural gas-fired assets. The rules affect decisions made for future investments in power supply resources and what modifications EKPC may need to make for the existing assets. Working with the Cabinet on the new environmental rules helps EKPC make the best decisions for the Cooperative in order to give its very best to its Owner-Members and Kentuckians.

At this point in time, even with EKPC's best efforts of engagement with the Cabinet and EPA, the waterfront presents much uncertainty. The Clean Power Plan is yet not fully vetted or known at this time. EPA has not finalized the rule. While EKPC has been engaged and worked with the Cabinet on a State Implementation, the targets are not certain. The forecast for existing coal-fired assets are unknown as well as for any investment decisions. The same uncertainty exists for the unfinalized rules, namely, Coal Combustion Rule, Effluent Limitation Guidelines and later, ozone National Ambient Air Quality standard.

As certainty reveals itself, EKPC stands ready and prepared to move ahead with the Cabinet and EPA in regards to environmental compliance in Kentucky.

SECTION 10.0

FINANCIAL PLANNING

SECTION 10.0

FINANCIAL PLANNING

807 KAR 5:058 Section 9(1-4). The integrated resource plan shall, at a minimum, include and discuss the following financial information: (1) Present (base year) value of revenue requirements stated in dollar terms; (2) Discount rate used in present value calculations; (3) Nominal and real revenue requirements by year; and (4) Average system rates (revenues per kilowatt hour) by year.

Table 9-1 provides the Present (base year) value of revenue requirements stated in dollar terms for the 2015 Integrated Resource Plan and the Nominal and Real Revenue Requirements (in $millions) from the Member Systems. The Average Rate for each of the forecasted years included in the plan is defined as the Nominal Revenue Requirements divided by the total Sales to Members (in cents/kWh) and is also included in Table 9-1 below.

The discount rate used in present value calculations is [redacted]. This rate is based on the weighted average cost of EKPC's outstanding long-term debt as of December 31, 2014 multiplied by a 1.50 TIER.

TABLE 9-1
EAST KENTUCKY POWER COOPERATIVE, INC.
REVENUE REQUIREMENTS AND AVERAGE SYSTEM RATES

Year	Sales to Members (MWh)	Total From Members Nominal $ ($000)	Total From Members Real 2015$ * ($000)	Total From Members PV @ [redacted] ($000)	Nominal Cents per kWh	Real Cents per kWh Real 2015$
2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
			** PV =	[redacted]		

* Assumes an annual inflation rate of [redacted]

** Present value of revenue requirements using EKPC's discount rate of [redacted] and a base date of 12/31/2014.

SECTION 11.0

SYSTEM MAP

SECTION 11.0

SYSTEM MAP

807 KAR 5:058 Section 8.(3)(a) The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multistate integrated system shall submit the following information for its operations within Kentucky and for the multistate utility system of which it is a part. A utility which purchases fifty (50) percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases its energy needs. (a) A map of existing and planned generating facilities, transmission facilities with a voltage rating of sixty-nine (69) kilovolts or greater, indicating their type and capacity, and locations and capacities of all interconnections with other utilities. The utility shall discuss any known, significant conditions which restrict transfer capabilities with other utilities.

Please see system map on the following page.

REDACTED

Entire page is redacted.